Chris Sandve
Chief Regulatory Officer
Phone: 604-623-3726
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

August 31, 2021

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

BC Hydro writes to file the attached Fiscal 2023 to Fiscal 2025 Revenue Requirements Application (the **Application**).

BC Hydro is requesting various approvals from the BCUC which, if approved, would result in a net bill decrease of 1.4 per cent on April 1, 2022, followed by net bill increases of 2.0 per cent on April 1, 2023 and 2.7 per cent on April 1, 2024. This represents an average annual increase of 1.1 per cent.[1]

BC Hydro is providing the Application as follows:[2]

Exhibit B-2	Application (Public)
Exhibit B-2-1	Appendices A to II (Public)
Exhibit B-2-2	Chapter 6 (Confidential Version)
Exhibit B-2-3	Chapter 10, Appendices U, V and W (Confidential until further notice)
Exhibit B-2-4	Appendices I and V (Confidential Version)
Exhibit B-2-5	Appendix JJ (Confidential)

BC Hydro has previously proposed a timetable for review of the Application.[3]

1 The net bill increase for a given year is the combination of the rate increase and the change in the Deferral Account Rate Rider for that year.

2 Appendix H is marked “confidential” but is now public.

3 Refer to Exhibit B-1.

BC Hydro requests the following information to be held confidential in accordance with Part IV of the BCUC's Rules of Practice and Procedure, for the reasons explained below:

1. Certain information in Chapter 6, Appendix I, and Appendix V, which is either customer-specific and/or commercially sensitive;
2. The entirety of Chapter 10, Appendix U, Appendix V, and Appendix W, which is to be released through a public announcement in mid to late September and needs to remain confidential until that time; and
3. The entirety of Appendix JJ related to Mandatory Reliability Standards.

Chapter 6, Appendix I and Appendix V - Customer-Specific / Commercially Sensitive Information

In Chapter 6 and Appendix I, BC Hydro has redacted the name of a BC Hydro project where the project either:

- Is driven by, or specially for, a customer (disclosure of such information may prejudice a customer's commercial or competitive position); or
- Pertains to a substation acquisition (disclosure of such information may prejudice BC Hydro's position in future negotiations).

In Appendix V, the information redacted pertains to the name or identifiable information of a customer. If disclosed, the information may potentially prejudice the customer's competitive position. BC Hydro has a contractual obligation to keep the information specifically related to the customer and the customer's project confidential.

For the purpose of this proceeding and on appropriate undertakings, as contemplated by the BCUC's Rules of Practice and Procedure, BC Hydro is able to make non-customer specific project information in Chapter 6 and Appendix I available to registered interveners. BC Hydro reserves the right to object to a request for access to confidential information on a case-by-case basis.

Chapter 10, Appendix U, Appendix V, and Appendix W – Information to be Released Soon Through Public Announcement

At this time, BC Hydro is filing Chapter 10 and Appendices U, V and W confidentially with the BCUC and can make this information available to registered interveners upon request and upon signing an appropriate undertaking to keep the information confidential. This information relates to BC Hydro's Electrification Plan.

The Electrification Plan will be released through a public announcement in mid to late September. Once that public announcement has been made, BC Hydro will provide notice to the BCUC so that these materials can be posted publicly and form part of the public record. Providing this information confidentially to the BCUC and interveners in advance of the public announcement will allow all parties to review the materials and draft information requests, on the same timeline as the rest of the Application.

Appendix JJ – Confidential Mandatory Reliability Standards Information

In the Application, we have split the discussion on Mandatory Reliability Standards (**MRS**) between public content in Chapter 5 and nine pages of confidential content in Appendix JJ. Appendix JJ is confidential and made available to the BCUC only for two related reasons:

- First, information related to the protection of cyber infrastructure is highly security sensitive and could compromise the safety and reliability of the Bulk Electric System by exposing it to physical attacks by malicious actors or cyberattacks; and
- Second, the BCUC's MRS Rules of Procedure, including the Compliance Monitoring Program Rules and Penalty Guidelines, make the framework and processes for reporting, auditing and oversight of MRS compliance confidential. While certain information about an entity's violations, if confirmed, may become public after the fact, there remains a presumption of confidentiality. The presumption of confidentiality is especially important where the subject-matter relates to a cyber-security incident or may otherwise jeopardize the security of the Bulk Electric System.

For further information, please contact Joe Maloney at 604-623-4348 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Chris Sandve
Chief Regulatory Officer

st/rh

Enclosure

BC Hydro
Power smart

List of Appendices

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix A

Financial Schedules

Revenue Requirements Model

Note 1: RRA (Revenue Requirement Application); TRR (Transmission Revenue Requirement)

Revenue Requirements Summary
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Cost of Energy**	3.0 L1	1,867.9	1,810.9	(57.0)	1,666.5	1,522.4	(144.0)	1,670.1	1,663.7	(6.4)	1,781.6	1,943.3	2,001.4
2	**Operating Costs**	3.0 L6	1,136.1	1,115.2	(20.9)	1,135.4	1,128.7	(6.6)	1,228.5	1,218.6	(9.9)	1,286.8	1,314.4	1,348.4
3	**Provisions & Other**	3.0 L12	116.4	176.8	60.4	95.4	163.7	68.3	101.4	97.4	(4.0)	104.9	96.7	95.3
4	**Taxes**	3.0 L18	249.8	249.7	(0.1)	262.2	256.8	(5.4)	263.8	271.4	7.6	283.5	298.3	309.2
5	**Amortization**	3.0 L21	977.8	977.7	(0.0)	998.0	999.5	1.6	1,023.7	1,066.7	43.1	1,023.3	1,050.0	1,101.0
6	**Finance Charges**	3.0 L27	874.9	1,656.8	781.8	743.3	251.6	(491.8)	555.6	720.8	165.2	581.2	564.5	704.1
7	**Return on Equity**	3.0 L34	712.0	704.9	(7.1)	712.0	687.5	(24.5)	712.0	704.4	(7.6)	712.0	712.0	712.0
8	**Miscellaneous Revenue**	3.0 L38	(240.6)	(247.3)	(6.7)	(247.0)	(261.1)	(14.1)	(289.0)	(300.5)	(11.5)	(288.5)	(292.9)	(295.3)
9	**Inter-Segment Revenue**	3.0 L47	(64.9)	(72.0)	(7.1)	(71.9)	15.0	86.9	(83.5)	(73.0)	10.5	(71.8)	(73.4)	(74.8)
	Deferral Accounts													
10	Deferral Account Additions	2.1 L54	3.1	52.2	49.1	3.5	393.3	389.8	15.5	(7.1)	(22.6)	2.8	3.7	2.4
11	Interest on Deferral Accounts	2.1 L55	15.4	15.9	0.5	4.0	9.0	5.0	0.7	6.6	6.0	5.0	2.8	1.8
12	Deferral Account Recoveries	2.1 L56	(392.5)	(403.9)	(11.4)	(238.3)	(451.4)	(213.1)	0.0	0.0	0.0	(106.6)	(55.3)	(28.9)
13	Total		(373.9)	(335.7)	38.2	(230.8)	(49.1)	181.7	16.2	(0.5)	(16.6)	(98.7)	(48.8)	(24.6)
	Other Regulatory Accounts													
14	Regulatory Account Additions	2.2 L208	(279.2)	(984.2)	(705.0)	(144.7)	381.2	525.9	(114.7)	(194.4)	(79.7)	(173.0)	(180.9)	(178.1)
15	Interest on Regulatory Accounts	2.2 L209	(33.1)	(32.6)	0.5	(30.0)	(27.2)	2.8	(25.1)	(24.6)	0.5	(24.4)	(23.8)	(24.6)
16	Regulatory Account Recoveries	2.2 L210	381.4	287.7	(93.7)	379.2	266.9	(112.3)	335.7	226.4	(109.3)	362.4	372.4	338.1
17	Total		69.1	(729.1)	(798.3)	204.4	620.9	416.5	195.8	7.3	(188.4)	165.0	167.6	135.3
	Subsidiary Net Income													
18	Powerex Trade Income		(176.3)	(189.2)	(13.0)	(176.3)	(386.4)	(210.2)	(158.7)	(158.7)	(0.0)	(224.2)	(224.2)	(224.2)
19	Powertech Net Income		(3.4)	(3.4)	0.0	(3.7)	0.9	4.6	(2.0)	(2.0)	(0.0)	(3.0)	(3.5)	(4.0)
20	Captive Insurance Net Income				0.0			0.0		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
21	Columbia Hydro Contractors Net Income				0.0			0.0		0.0	0.0	0.0	0.0	0.0
22	Total		(179.7)	(192.7)	(13.0)	(179.9)	(385.5)	(205.6)	(160.7)	(160.7)	(0.0)	(227.2)	(227.7)	(228.2)
23	**Less Other Utilities Revenue**	14.0 L24	(36.1)	(29.7)	6.4	(35.9)	(30.0)	5.9	(30.2)	(30.0)	0.2	(30.0)	(30.0)	(30.0)
24	**Less Liquefied Natural Gas Revenue**	14.0 L25	(0.5)	(1.3)	(0.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	**Less Deferral Account Rate Rider**	14.0 L32	0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	106.5	55.3	28.9
26	**Total Rate Revenue Requirement**		5,108.1	5,084.0	(24.2)	5,051.6	4,920.4	(131.1)	5,203.6	5,185.7	(17.9)	5,328.5	5,529.4	5,782.6
	Rate Revenue at Current Rates													
27	Total Domestic Revenue	14.0 L33	5,144.8	5,115.1	(29.6)	5,087.4	4,950.4	(137.0)	5,182.4	5,215.7	33.3	5,219.2	5,417.5	5,571.9
28	Less Other Utilities	Line 23	(36.1)	(29.7)	6.4	(35.9)	(30.0)	5.9	(30.2)	(30.0)	0.2	(30.0)	(30.0)	(30.0)
29	Less Liquefied Natural Gas Revenue	Line 24	(0.5)	(1.3)	(0.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Less Deferral Account Rate Rider	Line 25	0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	106.5	55.3	28.9
31	Revenue Subject to Rate Increase		5,108.1	5,084.0	(24.2)	5,051.6	4,920.4	(131.1)	5,152.2	5,185.7	33.5	5,295.7	5,442.8	5,570.8
32	**Revenue Shortfall**	L26 - L31	0.0	0.0	(0.0)	0.0	0.0	(0.0)	51.5	0.0	(51.5)	32.7	86.6	211.8
33	**Rate Increases**		6.85%	6.85%	-	(1.62%)	(1.62%)	-	1.00%	1.00%	-	0.62%	0.97%	2.18%
34	**Deferral Account Rate Rider**		-	-	-	-	-	-	-	-	-	(2.00%)	(1.00%)	(0.50%)
35	**Net Bill Impact**		1.76%	1.76%	-	(1.62%)	(1.62%)	-	1.00%	1.00%	-	(1.39%)	2.00%	2.69%

BC Hydro
F23-F25 RRA

Deferral Accounts
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Heritage Deferral Account													
1	Beginning of Year		(485.1)	(485.1)	0.0	(225.6)	(300.1)	(74.5)	64.8	64.8	0.0	90.1	48.4	27.4
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Additions	Line 60	0.0	(82.4)	(82.4)	0.0	77.8	77.8	0.0	22.9	22.9	0.0	0.0	0.0
4	Additions - F20 Compliance						60.6	60.6	0.0	0.0	0.0	0.0	0.0	0.0
5	Interest		(13.1)	(13.2)	(0.1)	(4.0)	(3.0)	0.9	3.5	2.3	(1.2)	2.1	1.1	0.7
6	Recovery		272.6	280.6	7.9	229.5	229.5	(0.0)	0.0	0.0	0.0	(43.7)	(22.2)	(11.0)
7	End of Year		(225.6)	(300.1)	(74.5)	0.0	64.8	64.8	68.4	90.1	21.7	48.4	27.4	17.1
	Non-Heritage Deferral Account													
8	Beginning of Year		76.1	76.1	0.0	(111.3)	204.7	316.0	(153.4)	(153.4)	0.0	(189.6)	(104.7)	(62.9)
9	Adjustment to Opening Balance		64.8	64.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Transfer to Load Variance		(287.3)	0.0	287.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Additions	Line 61	0.0	100.1	100.1	0.0	(112.7)	(112.7)	0.0	(15.5)	(15.5)	0.0	0.0	0.0
12	Additions - F20 Compliance						(351.6)	(351.6)	0.0	0.0		0.0	0.0	0.0
13	Additions - Waneta 2/3	15.0 L43	(3.1)	(1.3)	1.8	(3.5)	(5.0)	(1.5)	(15.5)	(15.5)	(0.0)	(2.8)	(3.7)	(2.4)
14	Interest		(4.8)	5.9	10.7	(2.1)	(5.7)	(3.6)	(8.4)	(5.2)	3.2	(4.4)	(2.5)	(1.6)
15	Recovery		43.0	(40.9)	(83.9)	116.8	116.8	0.0	0.0	0.0	0.0	92.0	47.9	25.3
16	End of Year		(111.3)	204.7	316.0	(0.0)	(153.4)	(153.4)	(177.3)	(189.6)	(12.3)	(104.7)	(62.9)	(41.7)
	Trade Income Deferral Account													
17	Beginning of Year		(258.8)	(258.8)	0.0	(107.9)	(173.7)	(65.8)	(226.7)	(226.7)	0.0	(233.6)	(125.5)	(71.0)
18	Adjustment to Opening Balance		(1.9)	(1.9)	0.0	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	0.0	0.0
19	Additions	Line 62	0.0	(68.7)	(68.7)	0.0	(210.2)	(210.2)	0.0	(0.0)	(0.0)	0.0	0.0	0.0
20	Additions - F20 Compliance						55.7	55.7	0.0	0.0		0.0	0.0	0.0
21	Interest		(6.8)	(8.6)	(1.8)	(1.9)	(3.5)	(1.6)	(0.4)	(7.0)	(6.5)	(5.3)	(2.9)	(1.8)
22	Recovery		159.5	164.2	4.7	109.8	105.1	(4.7)	0.0	0.0	0.0	113.4	57.5	28.5
23	End of Year		(107.9)	(173.7)	(65.8)	(0.0)	(226.7)	(226.7)	(227.1)	(233.6)	(6.5)	(125.5)	(71.0)	(44.2)
	Load Variance													
24	Beginning of Year		0.0	0.0	0.0	214.0	0.0	(214.0)	109.6	109.6	0.0	134.2	72.1	40.8
25	Adjustment to Opening Balance	Line 10	287.3	0.0	(287.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Transfer from NHDA						0.0		0.0	0.0		0.0	0.0	0.0
27	Additions	Line 63	0.0	0.0	0.0	0.0	85.8	85.8	0.0	20.9	20.9	0.0	0.0	0.0
28	Additions - F20 Compliance						20.3	20.3	0.0	0.0		0.0	0.0	0.0
29	Interest		9.3	0.0	(9.3)	3.9	3.5	(0.4)	4.9	3.7	(1.2)	3.1	1.7	1.0
30	Recovery		(82.7)	0.0	82.7	(217.8)	0.0	217.8	0.0	0.0	0.0	(65.1)	(33.0)	(16.4)
31	End of Year		214.0	0.0	(214.0)	0.0	109.6	109.6	114.5	134.2	19.7	72.1	40.8	25.4
	Biomass Energy Program Variance													
32	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	(14.3)	(14.3)	0.0	(20.6)	(11.1)	(6.3)
33	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Additions - Cost of Energy	Line 64	0.0	0.0	0.0	0.0	(14.7)	(14.7)	0.0	(5.7)	(5.7)	0.0	0.0	0.0
35	Additions - Revenue	Line 65	0.0	0.0	0.0	0.0	1.7	1.7	0.0	0.0	0.0	0.0	0.0	0.0
36	Additions - COE (F20 Compliance)						(4.3)	(4.3)	0.0	0.0		0.0	0.0	0.0
37	Additions - Revenue COE (F20 Compliance)						3.2	3.2	0.0	0.0		0.0	0.0	0.0
38	Interest		0.0	0.0	0.0	0.0	(0.3)	(0.3)	(0.2)	(0.5)	(0.3)	(0.5)	(0.3)	(0.2)
39	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	5.1	2.5
40	End of Year		0.0	0.0	0.0	0.0	(14.3)	(14.3)	(14.6)	(20.6)	(6.0)	(11.1)	(6.3)	(3.9)

BC Hydro
F23-F25 RRA

Schedule 2.1
Page 4

Deferral Accounts
($ million)

Line	Column	Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Low Carbon Fuel Credits Variance													
41	Beginning of Year											0.0	0.0	0.0
42	Adjustment to Opening Balance											0.0	0.0	0.0
43	Additions											0.0	0.0	0.0
44	Interest											0.0	0.0	0.0
45	Recovery											0.0	0.0	0.0
46	End of Year											0.0	0.0	0.0
	End of Year Balances													
47	Heritage	Line 7	(225.6)	(300.1)	(74.5)	0.0	64.8	64.8	68.4	90.1	21.7	48.4	27.4	17.1
48	Non-Heritage	Line 16	(111.3)	204.7	316.0	(0.0)	(153.4)	(153.4)	(177.3)	(189.6)	(12.3)	(104.7)	(62.9)	(41.7)
49	Trade Income	Line 23	(107.9)	(173.7)	(65.8)	(0.0)	(226.7)	(226.7)	(227.1)	(233.6)	(6.5)	(125.5)	(71.0)	(44.2)
50	Load Variance	Line 31	214.0	0.0	(214.0)	0.0	109.6	109.6	114.5	134.2	19.7	72.1	40.8	25.4
51	Biomass Energy Program Cost	Line 40	0.0	0.0	0.0	0.0	(14.3)	(14.3)	(14.6)	(20.6)	(6.0)	(11.1)	(6.3)	(3.9)
52	Low Carbon Fuel Credits Variance	Line 46	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	Total		(230.8)	(269.1)	(38.2)	0.0	(220.0)	(220.0)	(236.1)	(219.5)	16.6	(120.8)	(72.0)	(47.4)
	Summary													
54	Deferral Account Additions		(3.1)	(52.2)	(49.1)	(3.5)	(393.3)	(389.8)	(15.5)	7.1	22.6	(2.8)	(3.7)	(2.4)
55	Interest on Deferral Accounts		(15.4)	(15.9)	(0.5)	(4.0)	(9.0)	(5.0)	(0.7)	(6.6)	(6.0)	(5.0)	(2.8)	(1.8)
56	Deferral Account Recoveries		392.5	403.9	11.4	238.3	451.4	213.1	0.0	0.0	0.0	106.6	55.3	28.9
57	Adjustment to Opening Balance		62.9	62.9	0.0	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	0.0	0.0
58	Net Transfers		436.9	398.6	(38.2)	230.8	49.1	(181.7)	(16.2)	0.4	16.6	98.7	48.8	24.6
59	**Interest Rate**	8.0 L64	3.81%	3.74%	(0.07%)	3.73%	3.38%	(0.35%)	3.09%	3.07%	(0.02%)	3.01%	2.98%	3.11%
	Summary of Items Subject to Deferral													
60	Cost of Heritage Energy	4.0 L96	513.3	499.3	(14.0)	219.0	296.9	77.8	392.7	416.2	23.5	385.0	390.3	386.9
61	Cost of Non-Heritage Energy	4.0 L115	1,321.7	1,426.1	104.4	1,370.7	1,258.0	(112.7)	1,185.8	1,170.5	(15.3)	1,294.6	1,448.8	1,507.9
62	Trade Income	1.0 L18	(176.3)	(189.2)	(13.0)	(176.3)	(386.4)	(210.2)	(158.7)	(158.7)	(0.0)	(224.2)	(224.2)	(224.2)
63	Load Variance	14.0 L52	(5,099.7)	(5,079.5)	20.3	(5,036.3)	(4,950.5)	85.8	(5,187.7)	(5,218.6)	(30.9)	(5,306.8)	(5,510.9)	(5,765.2)
64	Biomass Energy Program Variance - COE	4.0 L116	35.8	31.6	(4.3)	80.7	66.0	(14.7)	102.4	99.6	(2.8)	113.3	115.7	118.1
65	Biomass Energy Program Variance - Revenue	14.0 L53	(9.0)	(5.8)	3.2	(15.2)	(13.5)	1.7	(15.9)	(18.9)	(2.9)	(21.7)	(18.5)	(17.4)
66	Low Carbon Fuel Credits Variance	15.0 L42	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

BC Hydro
F23-F25 RRA

Schedule 2.2
Page 5

Other Regulatory Accounts
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Demand-Side Management													
1	Beginning of Year		914.5	914.5	0.0	920.3	906.6	(13.7)	881.2	881.2	0.0	868.8	886.1	904.8
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Additions - DSM	5.0 L59	90.8	78.5	(12.4)	89.1	77.0	(12.0)	82.2	82.2	(0.0)	83.4	85.1	87.1
4	Additions - Low Carbon Electrification	5.0 L60	18.3	16.9	(1.4)	9.7	4.1	(5.6)	15.5	12.8	(2.7)	45.1	49.5	50.6
5	Amortization on Existing	7.0 L37	(103.3)	(103.3)	0.0	(107.4)	(106.5)	0.9	(108.0)	(107.4)	0.6	(111.2)	(116.0)	(119.3)
6	Amortization on Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	End of Year		920.3	906.6	(13.7)	911.7	881.2	(30.4)	871.0	868.8	(2.2)	886.1	904.8	923.2
	First Nations Costs													
8	Beginning of Year		85.0	85.0	0.0	71.4	69.5	(1.9)	53.9	53.9	0.0	37.0	19.9	2.4
9	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Additions	5.0 L61	3.2	2.5	(0.6)	2.4	1.9	(0.5)	2.1	2.1	(0.0)	1.8	1.8	1.8
11	Transfer from FN Settlement Provisions	Line 19	15.0	12.8	(2.1)	13.1	13.3	0.3	14.7	14.1	(0.5)	14.4	14.2	14.3
12	Interest		2.9	3.1	0.2	2.3	2.3	(0.0)	1.4	1.4	(0.0)	0.8	0.3	0.1
13	Recovery	5.0 L28	(34.7)	(34.1)	0.6	(33.7)	(33.1)	0.5	(34.4)	(34.4)	0.0	(34.1)	(33.9)	(16.6)
14	End of Year		71.4	69.5	(1.9)	55.5	53.9	(1.7)	37.6	37.0	(0.6)	19.9	2.4	1.9
	First Nations Settlement Provisions													
15	Beginning of Year		420.3	420.3	0.0	423.0	426.0	3.0	431.9	431.9	0.0	431.6	435.6	440.0
16	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Additions - Operating	5.01 L38	0.0	0.9	0.9	0.0	1.2	1.2	0.0	(4.5)	(4.5)	0.0	0.0	0.0
18	Additions - Accretion	8.0 L15	17.6	17.6	0.0	18.0	18.0	0.0	18.3	18.3	0.0	18.4	18.6	18.8
19	Transfer to First Nations Costs	Line 11	(15.0)	(12.8)	2.1	(13.1)	(13.3)	(0.3)	(14.7)	(14.1)	0.5	(14.4)	(14.2)	(14.3)
20	End of Year		423.0	426.0	3.0	427.9	431.9	4.0	435.5	431.6	(4.0)	435.6	440.0	444.4
	Site C Project													
21	Beginning of Year		491.3	491.3	0.0	508.4	508.4	0.0	523.3	523.3	0.0	542.1	569.0	597.6
22	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Additions	5.0 L62+8.0 L33	(1.7)	(1.5)	0.1	(2.4)	(2.2)	0.1	(7.0)	2.6	9.6	10.5	11.5	7.8
24	Interest		18.7	18.6	(0.1)	18.9	17.2	(1.7)	16.1	16.1	0.0	16.5	17.1	18.6
25	Recovery	5.0 L43	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(5.6)
26	End of Year		508.4	508.4	0.0	524.9	523.3	(1.6)	532.5	542.1	9.6	569.0	597.6	618.4
	Foreign Exchange Gains/Losses													
27	Beginning of Year		11.9	11.9	0.0	9.0	16.6	7.5	5.7	5.7	0.0	7.0	6.9	6.9
28	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Additions	8.0 L13	(2.3)	5.3	7.5	(1.5)	(10.7)	(9.2)	(2.6)	0.4	3.0	0.6	0.7	(0.1)
30	Recovery	8.0 L37	(0.5)	(0.5)	(0.0)	0.5	(0.1)	(0.6)	0.1	0.8	0.7	(0.6)	(0.7)	(0.7)
31	End of Year		9.0	16.6	7.5	8.0	5.7	(2.3)	3.3	7.0	3.6	6.9	6.9	6.1

BC Hydro
F23-F25 RRA

Schedule 2.2
Page 6

Other Regulatory Accounts
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
Column			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Pre-1996 Customer Contributions													
32	Beginning of Year		83.3	83.3	0.0	78.2	78.2	0.0	73.1	73.1	0.0	67.9	62.8	57.7
33	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Recovery	7.0 L38	(5.1)	(5.1)	0.0	(5.1)	(5.1)	0.0	(5.1)	(5.1)	0.0	(5.1)	(5.1)	(5.1)
35	End of Year		78.2	78.2	0.0	73.1	73.1	0.0	67.9	67.9	0.0	62.8	57.7	52.5
	Storm Restoration Costs													
36	Beginning of Year		58.0	58.0	0.0	29.0	20.8	(8.3)	(22.9)	(22.9)	0.0	(10.5)	(7.0)	(3.5)
37	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	Additions – Storm Restoration Costs	5.0 L63 - Line 39	0.0	(7.8)	(7.8)	0.0	(14.2)	(14.2)	0.0	0.0	0.0	0.0	0.0	0.0
39	Additions - Evacuation Relief			0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	Interest		1.6	1.1	(0.5)	0.5	0.0	(0.5)	(0.2)	(0.5)	(0.3)	(0.3)	(0.2)	(0.1)
41	Recovery	5.0 L29	(30.6)	(30.6)	(0.0)	(29.5)	(29.5)	(0.0)	12.9	12.9	0.0	3.8	3.7	3.6
42	End of Year		29.0	20.8	(8.3)	0.0	(22.9)	(22.9)	(10.2)	(10.5)	(0.3)	(7.0)	(3.5)	(0.0)
	Capital Project Investigation													
43	Beginning of Year		10.5	10.5	0.0	5.2	5.2	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
44	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Recovery	5.0 L30	(5.2)	(5.2)	(0.0)	(5.2)	(5.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
46	End of Year		5.2	5.2	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Amortization of Capital Additions													
47	Beginning of Year		18.4	18.4	0.0	9.2	8.9	(0.4)	(0.4)	(0.4)	0.0	2.5	1.7	0.8
48	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	Additions	7.0 L33	0.0	(0.4)	(0.4)	0.0	0.1	0.1	0.0	0.7	0.7	0.0	0.0	0.0
50	Interest		0.5	0.6	0.1	0.2	0.0	(0.1)	(0.0)	0.0	0.1	0.1	0.0	0.0
51	Recovery	7.0 L39	(9.7)	(9.7)	0.0	(9.4)	(9.4)	0.0	2.1	2.1	0.0	(0.9)	(0.9)	(0.8)
52	End of Year		9.2	8.9	(0.4)	(0.0)	(0.4)	(0.4)	1.7	2.5	0.8	1.7	0.8	0.0
	Total Finance Charges													
53	Beginning of Year		20.2	20.2	0.0	10.1	11.1	0.9	(60.8)	(60.8)	0.0	38.6	25.8	12.9
54	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
55	Transfer from Rock Bay	Line 87								(0.1)	(0.1)			
56	Additions	8.0 L32	0.0	0.9	0.9	0.0	(61.7)	(61.7)	0.0	25.4	25.4	0.0	0.0	0.0
57	Recovery	8.0 L39+ L41	(10.1)	(10.1)	0.0	(10.1)	(10.1)	0.0	74.1	74.1	0.0	(12.9)	(12.9)	(12.9)
58	End of Year		10.1	11.1	0.9	(0.0)	(60.8)	(60.8)	13.3	38.6	25.4	25.8	12.9	0.0
	Smart Metering & Infrastructure													
59	Beginning of Year		217.2	217.2	0.0	195.5	195.4	(0.1)	173.0	173.0	0.0	151.3	129.7	108.1
60	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
61	Additions - Deferred Operating	5.0 L64	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
62	Additions - DSMD Write-Off	5.01 L40	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
63	Additions - Miscellaneous Revenue	15.0 L44	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
64	Interest		7.7	7.8	0.0	6.8	6.2	(0.5)	4.9	4.9	(0.0)	4.2	3.5	3.0
65	Recovery	5.0 L31	(29.4)	(29.6)	(0.2)	(28.5)	(28.6)	(0.2)	(26.6)	(26.6)	0.0	(25.8)	(25.1)	(24.6)
66	End of Year		195.5	195.4	(0.1)	173.8	173.0	(0.8)	151.4	151.3	(0.0)	129.7	108.1	86.5

BC Hydro
F23-F25 RRA

Schedule 2.2
Page 7

Other Regulatory Accounts
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Non-Current Pension Cost													
67	Beginning of Year		485.5	485.5	0.0	364.1	210.1	(154.0)	114.0	114.0	0.0	1.7	(27.9)	(57.6)
68	Adjustment to Opening Balance		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.2**	0.2	**0.0**	**0.0**	**0.0**
69	OCI Deferral	9.0 L8	(70.0)	(317.2)	(247.2)	0.0	(156.3)	(156.3)	0.0	(105.8)	(105.8)	0.0	0.0	0.0
70	Additions		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
71	Recovery - Operating	5.0 L32	(51.4)	(56.8)	(5.4)	(51.4)	(46.0)	5.4	(114.6)	(114.6)	0.0	(29.7)	(29.7)	(29.7)
72	Recovery - Finance Charges	8.0 L38	0.0	98.6	98.6	0.0	106.2	106.2	0.0	108.0	108.0	0.0	0.0	0.0
73	Transfer to PEB Current Pension-Addition	Line 129	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
74	Transfer to PEB Current Pension-Recovery	Line 130	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
75	End of Year		364.1	210.1	(154.0)	312.7	114.0	(198.7)	(0.6)	1.7	2.4	(27.9)	(57.6)	(87.3)
	Environmental Provisions													
76	Beginning of Year		278.5	278.5	0.0	236.2	305.1	68.8	321.0	321.0	0.0	273.8	234.2	188.5
77	Adjustment to Opening Balance		**0.0**	**0.0**	0.0	**0.0**	**(0.0)**	(0.0)	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
78	Additions - Deferred Operating	5.01 L39	0.0	51.2	51.2	0.0	51.2	51.2	0.0	(0.8)	(0.8)	0.0	0.0	0.0
79	Additions - Accretion	8.0 L16	5.5	4.8	(0.7)	4.8	2.9	(1.9)	3.4	5.2	1.7	4.6	4.1	3.4
80	Transfer to Rock Bay	Line 86	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
81	Transfer to Remediation (Asbestos)	Line 102	**(21.7)**	**(8.2)**	13.5	**(18.8)**	**(8.0)**	10.8	**(22.4)**	**(12.6)**	9.8	**(10.4)**	**(9.4)**	**(8.9)**
82	Transfer to Remediation (PCB)	Line 103	**(26.1)**	**(21.2)**	4.9	**(26.0)**	**(30.1)**	(4.1)	**(39.1)**	**(39.0)**	0.0	**(33.7)**	**(40.4)**	**(14.9)**
83	End of Year		236.2	305.1	68.8	196.2	321.0	124.8	263.0	273.8	10.8	234.2	188.5	168.1
	Rock Bay Remediation													
84	Beginning of Year		(20.5)	(20.5)	0.0	(10.3)	(10.4)	(0.1)	(0.2)	(0.2)	0.0	0.0	0.0	0.0
85	Adjustment to Opening Balance		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
86	Transfer from Environmental	Line 80	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
87	Transfer to Finance Charge	Line 55								**0.1**	0.1			
88	Interest		(0.6)	**(0.6)**	(0.1)	**(0.2)**	**(0.2)**	(0.1)	**(0.0)**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
89	Recovery	5.01 L26	10.8	10.8	0.0	10.4	10.4	(0.0)	0.1	0.1	0.0	0.0	0.0	0.0
90	End of Year		(10.3)	(10.4)	(0.1)	(0.0)	(0.2)	(0.1)	(0.1)	0.0	0.1	0.0	0.0	0.0
	IFRS PP&E													
91	Beginning of Year		1,064.4	1,064.4	0.0	1,079.2	1,079.2	(0.0)	1,070.6	1,070.6	0.0	1,039.0	1,007.5	975.9
92	Adjustment to Opening Balance		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
93	Additions - Deferred Operating	5.0 L65	44.8	44.8	0.0	22.4	22.4	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
94	Recovery	5.0 L34	(29.9)	(29.9)	(0.0)	(31.0)	(31.0)	(0.0)	(31.6)	(31.6)	0.0	(31.6)	(31.6)	(31.6)
95	End of Year		1,079.2	1,079.2	(0.0)	1,070.6	1,070.6	(0.0)	1,039.0	1,039.0	0.0	1,007.5	975.9	944.4
	IFRS Pension													
96	Beginning of Year		497.1	497.1	0.0	458.9	458.9	0.0	420.6	420.6	0.0	382.4	344.2	305.9
97	Adjustment to Opening Balance		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
98	Recovery	5.0 L35	(38.2)	(38.2)	0.0	(38.2)	(38.2)	0.0	(38.2)	(38.2)	0.0	(38.2)	(38.2)	(38.2)
99	End of Year		458.9	458.9	0.0	420.6	420.6	0.0	382.4	382.4	0.0	344.2	305.9	267.7

Other Regulatory Accounts
($ million)

Line	Column	Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Remediation													
100	Beginning of Year		(30.8)	(30.8)	0.0	(15.4)	(34.3)	(18.8)	(26.5)	(26.5)	0.0	(33.9)	(22.6)	(11.3)
101	Adjustment to Opening Balance		0.0	0.0	(0.0)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
102	Transfer from Env. Prov. (Asbestos)	Line 81	21.7	8.2	(13.5)	18.8	8.0	(10.8)	22.4	12.6	(9.8)	10.4	9.4	8.9
103	Transfer from Env. Prov. (PCB)	Line 82	26.1	21.2	(4.9)	26.0	30.1	4.1	39.1	39.0	(0.0)	33.7	40.4	14.9
104	Interest		(0.9)	(1.3)	(0.4)	(0.3)	(1.2)	(0.9)	(0.1)	(0.9)	(0.9)	(0.8)	(0.5)	(0.2)
105	Recovery	5.01 L23:L24	(31.6)	(31.6)	0.0	(29.2)	(29.2)	(0.0)	(58.1)	(58.1)	0.0	(32.0)	(38.0)	(12.3)
106	End of Year		(15.4)	(34.3)	(18.8)	(0.1)	(26.5)	(26.4)	(23.2)	(33.9)	(10.7)	(22.6)	(11.3)	(0.0)
	Real Property Sales													
107	Beginning of Year		49.2	49.2	0.0	50.9	56.2	5.3	46.7	46.7	0.0	48.1	49.5	51.0
108	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
109	Additions	5.0 L67+5.01 L41	0.0	5.3	5.3	(0.0)	(10.9)	(10.9)	0.0	0.0	0.0	0.0	0.0	0.0
110	Interest		1.7	1.7	0.0	1.4	1.4	(0.0)	1.5	1.4	(0.0)	1.4	1.5	1.6
111	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
112	End of Year		50.9	56.2	5.3	52.3	46.7	(5.6)	48.1	48.1	(0.0)	49.5	51.0	52.6
	Debt Management													
113	Beginning of Year		163.2	163.2	0.0	276.5	952.9	676.4	448.6	448.6	0.0	462.1	446.9	431.7
114	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
115	Additions	8.0 L18	100.9	777.3	676.4	0.0	(516.6)	(516.6)	0.0	22.6	22.6	0.0	0.0	0.0
116	Recovery	8.0 L40	12.4	12.4	0.0	12.4	12.4	0.0	(9.1)	(9.1)	0.0	(15.2)	(15.2)	(15.2)
117	End of Year		276.5	952.9	676.4	288.9	448.6	159.8	439.5	462.1	22.6	446.9	431.7	416.5
	Dismantling Cost													
118	Beginning of Year		48.3	48.3	0.0	24.1	16.0	(8.2)	(12.4)	(12.4)	0.0	(4.5)	(3.0)	(1.5)
119	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
120	Additions	5.01 L42	0.0	(8.5)	(8.5)	0.0	(3.8)	(3.8)	0.0	4.9	4.9	0.0	0.0	0.0
121	Interest		1.4	1.6	0.3	0.4	(0.1)	(0.5)	(0.1)	(0.3)	(0.2)	(0.1)	(0.1)	(0.0)
122	Recovery	5.01 L25	(25.5)	(25.5)	0.0	(24.6)	(24.6)	(0.0)	3.3	3.3	0.0	1.6	1.6	1.5
123	End of Year		24.1	16.0	(8.2)	(0.0)	(12.4)	(12.4)	(9.1)	(4.5)	4.6	(3.0)	(1.5)	(0.0)
	PEB Current Pension Costs													
124	Beginning of Year		(1.7)	(1.7)	0.0	(0.9)	(1.8)	(0.9)	(6.7)	(6.7)	0.0	(24.8)	(16.5)	(8.3)
125	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
126	OCI Deferral		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
127	Additions	5.0 L66	0.0	(0.9)	(0.9)	0.0	(5.8)	(5.8)	0.0	(24.8)	(24.8)	0.0	0.0	0.0
128	Recovery - Operating	5.0 L33	0.9	0.9	(0.0)	0.9	0.9	(0.0)	6.7	6.7	0.0	8.3	8.3	8.3
129	Transfer from Non-Current Pension-Addition	Line 73	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
130	Transfer from Non-Current Pension-Recovery	Line 74	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
131	End of Year		(0.9)	(1.8)	(0.9)	0.0	(6.7)	(6.7)	(0.0)	(24.8)	(24.8)	(16.5)	(8.3)	0.0
	Customer Crisis Fund													
132	Beginning of Year		(2.6)	(2.6)	0.0	(2.9)	(5.3)	(2.4)	33.8	33.8	0.0	34.9	21.1	7.4
133	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
134	Additions - CCF	5.0 L68 - Line135	(0.3)	(2.7)	(2.4)	(0.3)	0.9	1.2	0.0	0.0	(0.0)	0.0	0.0	0.0
135	Additions - COVID-19 Relief operating costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
136	Additions - COVID-19 Residential Grants	14.0 L49	0.0	0.0	0.0	0.0	37.3	37.3	0.0	0.0	0.0	0.0	0.0	0.0
137	Interest		0.0	0.0	0.0	(0.1)	1.0	1.1	1.0	1.0	0.0	0.8	0.4	0.0
138	Recovery	5.0 L37	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(14.6)	(14.2)	(13.8)
139	End of Year		(2.9)	(5.3)	(2.4)	(3.3)	33.8	37.1	34.9	34.9	0.0	21.1	7.4	(6.4)

Other Regulatory Accounts
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
Column			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Mining Customer Payment Plan													
140	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	7.3	7.3	0.0	7.5	5.0	2.6
141	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
142	Additions	5.0 L70	0.0	0.0	0.0	0.0	0.7	0.7	0.0	0.0	0.0	0.0	0.0	0.0
143	Additions - COVID-19 SGS Waivers	14.0 L50	0.0	0.0	0.0	0.0	6.3	6.3	0.0	0.0	0.0	0.0	0.0	0.0
144	Interest		0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.0	0.2	0.1	0.0
145	Recovery	5.0 L38	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(2.6)	(2.6)	(2.5)
146	End of Year		0.0	0.0	0.0	0.0	7.3	7.3	7.5	7.5	0.0	5.0	2.6	0.1
	Project Write-off Costs													
147	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	16.7	16.7	0.0	7.8	5.5	3.2
148	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
149	Additions	5.01 L43	0.0	0.0	0.0	0.0	16.4	16.4	0.0	0.0	0.0	0.0	0.0	0.0
150	Interest		0.0	0.0	0.0	0.0	0.2	0.2	0.1	0.4	0.2	0.2	0.1	0.1
151	Recovery	5.01 L27	0.0	0.0	0.0	0.0	0.0	0.0	(9.3)	(9.3)	0.0	(2.5)	(2.5)	(2.5)
152	End of Year		0.0	0.0	0.0	0.0	16.7	16.7	7.6	7.8	0.2	5.5	3.2	0.8
	Electric Vehicle Costs													
153	Beginning of Year		0.0	0.0	0.0	2.3	0.0	(2.3)	4.4	4.4	0.0	7.4	4.9	2.5
154	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0
155	Additions - Operating Costs	5.0 L69	1.9	0.0	(1.9)	1.7	3.3	1.6	1.8	2.1	0.4	0.0	0.0	0.0
156	Additions - Cost of Energy	4.0 L77	0.2	0.0	(0.2)	0.3	0.3	0.1	0.4	0.1	(0.2)	0.0	0.0	0.0
157	Additions - Depreciation	7.0 L30:L31	0.2	0.0	(0.2)	0.5	0.7	0.2	0.5	0.4	(0.1)	0.0	0.0	0.0
158	Interest		0.0	0.0	(0.0)	0.1	0.1	(0.1)	0.2	0.2	(0.0)	0.2	0.1	0.0
159	Recovery	5.0 L36	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(2.6)	(2.6)	(2.5)
160	End of Year		2.3	0.0	(2.3)	4.9	4.4	(0.6)	7.2	7.4	0.2	4.9	2.5	0.0
	Mandatory Reliability Standard Costs													
161	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	10.8	5.4
162	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
163	Additions	5.0 L71	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.9	15.9	0.0	0.0	0.0
164	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.4	0.2	0.1
165	Recovery	5.0 L39:L41	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(5.8)	(5.6)	(5.5)
166	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	16.1	10.8	5.4	0.0
	Load Attraction Costs													
167	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.7	17.9
168	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
169	Additions	5.0 L72	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.7	9.7	8.8
170	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4	0.7
171	Recovery	5.0 L42	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.8)	(1.6)
172	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.7	17.9	25.8
	Depreciation Study													
173	Beginning of Year									0.0	0.0	29.1	19.4	9.7
174	Adjustment to Opening Balance									0.0	0.0			
175	Additions	7.0 L32								28.6	28.6	0.0	0.0	0.0
176	Interest									0.4	0.4	0.7	0.7	0.7
177	Recovery	7.0 L40								0.0	0.0	(10.4)	(10.4)	(10.4)
178	End of Year									29.1	29.1	19.4	9.7	(0.0)

BC Hydro
F23-F25 RRA

Schedule 2.2
Page 10

Other Regulatory Accounts
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	End of Year Balances													
179	Demand-Side Management	Line 7	920.3	906.6	(13.7)	911.7	881.2	(30.4)	871.0	868.8	(2.2)	886.1	904.8	923.2
180	First Nations Costs	Line 14	71.4	69.5	(1.9)	55.5	53.9	(1.7)	37.6	37.0	(0.6)	19.9	2.4	1.9
181	First Nations Settlement Provisions	Line 20	423.0	426.0	3.0	427.9	431.9	4.0	435.5	431.6	(4.0)	435.6	440.0	444.4
182	Site C Project	Line 26	508.4	508.4	0.0	524.9	523.3	(1.6)	532.5	542.1	9.6	569.0	597.6	618.4
183	Foreign Exchange Gains/Losses	Line 31	9.0	16.6	7.5	8.0	5.7	(2.3)	3.3	7.0	3.6	6.9	6.9	6.1
184	Pre-1996 Customer Contributions	Line 35	78.2	78.2	0.0	73.1	73.1	0.0	67.9	67.9	0.0	62.8	57.7	52.5
185	Storm Restoration Costs	Line 42	29.0	20.8	(8.3)	0.0	(22.9)	(22.9)	(10.2)	(10.5)	(0.3)	(7.0)	(3.5)	(0.0)
186	Capital Project Investigation	Line 46	5.2	5.2	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
187	Amortization of Capital Additions	Line 52	9.2	8.9	(0.4)	(0.0)	(0.4)	(0.4)	1.7	2.5	0.8	1.7	0.8	0.0
188	Total Finance Charges	Line 58	10.1	11.1	0.9	(0.0)	(60.8)	(60.8)	13.3	38.6	25.4	25.8	12.9	0.0
189	Smart Metering & Infrastructure	Line 66	195.5	195.4	(0.1)	173.8	173.0	(0.8)	151.4	151.3	(0.0)	129.7	108.1	86.5
190	Non-Current Pension Cost	Line 75	364.1	210.1	(154.0)	312.7	114.0	(198.7)	(0.6)	1.7	2.4	(27.9)	(57.6)	(87.3)
191	Environmental Provisions	Line 83	236.2	305.1	68.8	196.2	321.0	124.8	263.0	273.8	10.8	234.2	188.5	168.1
192	Rock Bay Remediation	Line 90	(10.3)	(10.4)	(0.1)	(0.0)	(0.2)	(0.1)	(0.1)	0.0	0.1	0.0	0.0	0.0
193	IFRS PP&E	Line 95	1,079.2	1,079.2	(0.0)	1,070.6	1,070.6	(0.0)	1,039.0	1,039.0	0.0	1,007.5	975.9	944.4
194	IFRS Pension	Line 99	458.9	458.9	0.0	420.6	420.6	0.0	382.4	382.4	0.0	344.2	305.9	267.7
195	Remediation	Line 106	(15.4)	(34.3)	(18.8)	(0.1)	(26.5)	(26.4)	(23.2)	(33.9)	(10.7)	(22.6)	(11.3)	(0.0)
196	Real Property Sales	Line 112	50.9	56.2	5.3	52.3	46.7	(5.6)	48.1	48.1	(0.0)	49.5	51.0	52.6
197	Debt Management	Line 117	276.5	952.9	676.4	288.9	448.6	159.8	439.5	462.1	22.6	446.9	431.7	416.5
198	Dismantling Cost	Line 123	24.1	16.0	(8.2)	(0.0)	(12.4)	(12.4)	(9.1)	(4.5)	4.6	(3.0)	(1.5)	(0.0)
199	PEB Current Pension Costs	Line 131	(0.9)	(1.8)	(0.9)	0.0	(6.7)	(6.7)	(0.0)	(24.8)	(24.8)	(16.5)	(8.3)	0.0
200	Customer Crisis Fund	Line 139	(2.9)	(5.3)	(2.4)	(3.3)	33.8	37.1	34.9	34.9	0.0	21.1	7.4	(6.4)
201	Mining Customer Payment Plan	Line 146	0.0	0.0	0.0	0.0	7.3	7.3	7.5	7.5	0.0	5.0	2.6	0.1
202	Project Write-off Costs	Line 152	0.0	0.0	0.0	0.0	16.7	16.7	7.6	7.8	0.2	5.5	3.2	0.8
203	Electric Vehicle Costs	Line 160	2.3	0.0	(2.3)	4.9	4.4	(0.6)	7.2	7.4	0.2	4.9	2.5	0.0
204	Mandatory Reliability Standard Costs	Line 166	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	16.1	10.8	5.4	0.0
205	Load Attraction Costs	Line 172	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.7	17.9	25.8
206	Depreciation Study	Line 178	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.1	29.1	19.4	9.7	(0.0)
207	Total		4,722.1	5,273.1	551.0	4,517.7	4,495.9	(21.8)	4,300.1	4,383.1	83.0	4,218.1	4,050.5	3,915.2
	Summary													
208	Regulatory Account Additions		279.2	984.2	705.0	144.7	(381.2)	(525.9)	114.7	194.4	79.7	173.0	180.9	178.1
209	Interest on Regulatory Accounts		33.1	32.6	(0.5)	30.1	27.2	(2.9)	25.1	24.6	(0.5)	24.4	23.8	24.6
210	Regulatory Account Recoveries		(381.4)	(287.7)	93.7	(379.2)	(266.9)	112.3	(335.7)	(226.4)	109.3	(362.4)	(372.4)	(338.1)
211	Adjustments to Opening Balances		0.1	0.1	(0.0)	0.0	0.0	0.0	0.0	0.3	0.3	0.0	0.0	0.0
212	OCI Deferral (Pension)		(70.0)	(317.2)	(247.2)	0.0	(156.3)	(156.3)	0.0	(105.8)	(105.8)	0.0	0.0	0.0
213	Regulatory Account Net Transfers		(139.0)	412.0	551.0	(204.4)	(777.2)	(572.8)	(195.8)	(112.8)	83.0	(165.0)	(167.6)	(135.3)
214	**Interest Rate**	8.0 L64	3.81%	3.74%	(0.07%)	3.73%	3.38%	(0.35%)	3.09%	3.07%	(0.02%)	3.01%	2.98%	3.11%

BC Hydro
F23-F25 RRA

Schedule 3.0
Page 11

Reconciliation of Current and Gross Views
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
		Column	1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Cost of Energy													
1	Total Gross	4.0 L1	1,867.9	1,810.9	(57.0)	1,666.5	1,522.4	(144.0)	1,670.1	1,663.7	(6.4)	1,781.6	1,943.3	2,001.4
2	Deferral Account Additions	4.0 L2	(0.2)	(18.7)	(18.5)	(0.3)	189.7	189.9	(0.4)	(21.3)	(21.0)	0.0	0.0	0.0
3	Subtotal before Recoveries		1,867.7	1,792.2	(75.5)	1,666.2	1,712.1	45.9	1,669.8	1,642.3	(27.4)	1,781.6	1,943.3	2,001.4
4	Deferral Account Recoveries	4.0 L4	(233.0)	(239.7)	(6.7)	(128.5)	(346.3)	(217.8)	0.0	0.0	0.0	6.8	2.2	(0.4)
5	Total Current	4.0 L5	1,634.8	1,552.5	(82.3)	1,537.7	1,365.8	(171.9)	1,669.8	1,642.3	(27.4)	1,788.4	1,945.5	2,001.0
	Operating Costs													
6	Total Gross	5.0 L1	1,136.1	1,115.2	(20.9)	1,135.4	1,128.7	(6.6)	1,228.5	1,218.6	(9.9)	1,286.8	1,314.4	1,348.4
7	Deferral Account Additions	5.0 L2	0.0	1.4	1.4	0.0	0.0	0.0	0.0	(1.4)	(1.4)	0.0	0.0	0.0
8	Regulatory Account Additions	5.0 L3	(159.0)	(132.6)	26.4	(125.4)	(91.8)	33.6	(102.0)	(90.7)	11.3	(139.4)	(146.4)	(148.6)
9	Subtotal before Recoveries	5.0 L4	977.1	984.0	6.9	1,010.0	1,036.9	26.9	1,126.5	1,126.5	0.0	1,147.4	1,167.9	1,199.9
10	Regulatory Account Recoveries	5.0 L5	218.7	223.6	4.9	216.7	210.9	(5.8)	225.8	225.8	(0.0)	173.2	172.3	160.3
11	Total Current	5.0 L6	1,195.8	1,207.6	11.8	1,226.7	1,247.9	21.2	1,352.3	1,352.3	(0.0)	1,320.5	1,340.3	1,360.2
	Provisions & Other													
12	Total Gross	5.01 L1	116.4	176.8	60.4	95.4	163.7	68.3	101.4	97.4	(4.0)	104.9	96.7	95.3
13	Deferral Account Additions	5.01 L2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Regulatory Account Additions	5.01 L3	0.0	(48.0)	(48.0)	0.0	(53.0)	(53.0)	0.0	0.4	0.4	0.0	0.0	0.0
15	Subtotal before Recoveries	5.01 L4	116.4	128.7	12.4	95.4	110.7	15.3	101.4	97.8	(3.6)	104.9	96.7	95.3
16	Regulatory Account Recoveries	5.01 L5	46.3	46.3	(0.0)	43.3	43.3	0.0	63.9	63.9	0.0	32.9	38.9	13.3
17	Total Current	5.01 L6	162.6	175.0	12.4	138.7	154.0	15.3	165.3	161.7	(3.6)	137.8	135.6	108.6
	Taxes													
18	Total Gross	6.0 L1	249.8	249.7	(0.1)	262.2	256.8	(5.4)	263.8	271.4	7.6	283.5	298.3	309.2
19	Deferral Account Additions	6.0 L2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Total Current	6.0 L4	249.8	249.7	(0.1)	262.2	256.8	(5.4)	263.8	271.4	7.6	283.5	298.3	309.2
	Amortization													
21	Total Gross	7.0 L1	977.8	977.7	(0.0)	998.0	999.5	1.6	1,023.7	1,066.7	43.1	1,023.3	1,050.0	1,101.0
22	Deferral Account Additions	7.0 L2	0.0	(0.4)	(0.4)	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0
23	Regulatory Account Additions	7.0 L3	(0.2)	0.4	0.7	(0.5)	(0.8)	(0.3)	(0.5)	(29.8)	(29.3)	0.0	0.0	0.0
24	Subtotal before Recoveries	7.0 L4	977.5	977.8	0.3	997.5	999.0	1.6	1,023.1	1,036.9	13.8	1,023.3	1,050.0	1,101.0
25	Regulatory Account Recoveries	7.0 L5	118.1	118.1	(0.0)	121.9	121.0	(0.9)	111.1	110.5	(0.6)	127.7	132.4	135.7
26	Total Current	7.0 L6	1,095.7	1,095.9	0.3	1,119.4	1,120.0	0.6	1,134.2	1,147.4	13.2	1,150.9	1,182.4	1,236.6
	Finance Charges													
27	Total Gross	8.0 L1	874.9	1,656.8	781.8	743.3	251.6	(491.8)	555.6	720.8	165.2	581.2	564.5	704.1
28	Total Finance Charge Regulatory Acct. Additions	8.0 L4	0.0	(0.9)	(0.9)	0.0	61.7	61.7	0.0	(25.4)	(25.4)	0.0	0.0	0.0
29	Other Regulatory Account Additions	8.0 L2-L3+L5	(119.8)	(803.1)	(683.3)	(18.6)	509.0	527.6	(11.9)	(48.8)	(36.9)	(33.6)	(34.5)	(29.6)
30	Interest on Regulatory Accounts	8.0 L6	(17.7)	(16.7)	1.0	(26.0)	(18.2)	7.8	(24.5)	(18.0)	6.5	(19.4)	(21.0)	(22.8)
31	Subtotal before Recoveries		737.5	836.1	98.6	698.7	804.1	105.3	519.3	628.6	109.3	528.1	508.9	651.7
32	Regulatory Account Recoveries	8.0 L8	(1.7)	(100.3)	(98.6)	(2.8)	(108.3)	(105.6)	(65.2)	(173.8)	(108.7)	28.7	28.8	28.8
33	Total Current		735.8	735.8	(0.0)	696.0	695.7	(0.2)	454.1	454.8	0.6	556.9	537.7	680.5

BC Hydro
F23-F25 RRA

Schedule 3.0
Page 12

Reconciliation of Current and Gross Views
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Return on Equity													
34	Total Gross	9.0 L33	712.0	704.9	(7.1)	712.0	687.5	(24.5)	712.0	704.4	(7.6)	712.0	712.0	712.0
35	Subtotal before Recoveries		712.0	704.9	(7.1)	712.0	687.5	(24.5)	712.0	704.4	(7.6)	712.0	712.0	712.0
36	Regulatory Account Recoveries				0.0			0.0			0.0			
37	Total Current		712.0	704.9	(7.1)	712.0	687.5	(24.5)	712.0	704.4	(7.6)	712.0	712.0	712.0
	Miscellaneous Revenue													
38	Total Gross	15.0 L1	(240.6)	(247.3)	(6.7)	(247.0)	(261.1)	(14.1)	(289.0)	(300.5)	(11.5)	(288.5)	(292.9)	(295.3)
39	Deferral Account Additions	15.0 L2	3.1	1.3	(1.8)	3.5	5.0	1.5	15.5	15.5	0.0	2.8	3.7	2.4
40	Regulatory Account Additions	15.0 L3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Subtotal before Recoveries	15.0 L4	(237.5)	(246.0)	(8.5)	(243.6)	(256.1)	(12.6)	(273.5)	(285.0)	(11.5)	(285.7)	(289.2)	(292.8)
42	Total Current	15.0 L5	(237.5)	(246.0)	(8.5)	(243.6)	(256.1)	(12.6)	(273.5)	(285.0)	(11.5)	(285.7)	(289.2)	(292.8)
	Inter-Segment Revenue													
43	Powerex - Business Support Allocation	3.1 L15	(2.9)	(2.9)	0.0	(2.9)	(2.9)	0.0	(2.9)	(2.9)	0.0	(0.3)	(0.3)	(0.4)
44	2020 TPA Revaluation (Mark-to-Market (gains)/losses)	3.1 L16	(1.4)	0.8	2.2	0.0	90.0	90.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Powerex PTP Charges	3.4 L19	(41.5)	(49.8)	(8.3)	(34.0)	(41.7)	(7.8)	(34.4)	(38.20)	(3.8)	(39.0)	(39.8)	(40.6)
46	BC Hydro PTP Charges	3.4 L20	(19.1)	(20.1)	(1.0)	(35.0)	(30.4)	4.7	(46.3)	(31.91)	14.3	(32.5)	(33.2)	(33.9)
47	Total		(64.9)	(72.0)	(7.1)	(71.9)	15.0	86.9	(83.5)	(73.0)	10.5	(71.8)	(73.4)	(74.8)
	Powerex Trade Income													
48	Total Gross	1.0 L18	(176.3)	(189.2)	(13.0)	(176.3)	(386.4)	(210.2)	(158.7)	(158.7)	(0.0)	(224.2)	(224.2)	(224.2)
49	TIDA Additions	2.1 L19+L20	0.0	68.7	68.7	0.0	154.5	154.5	0.0	0.0	0.0	0.0	0.0	0.0
50	TIDA Recoveries	2.1 L22	(159.5)	(164.2)	(4.7)	(109.8)	(105.1)	4.7	0.0	0.0	0.0	(113.4)	(57.5)	(28.5)
51	Total Current		(335.8)	(284.8)	51.0	(286.1)	(337.0)	(51.0)	(158.7)	(158.7)	(0.0)	(337.6)	(281.7)	(252.7)
52	**Powertech Net Income**	1.0 L19	(3.4)	(3.4)	0.0	(3.7)	0.9	4.6	(2.0)	(2.0)	(0.0)	(3.0)	(3.5)	(4.0)
53	**Captive Insurance Net Income**	1.0 L20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
54	**Columbia Hydro Contractors Net Income**	1.0 L21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
55	**Other Utilities Revenue**	14.0 L24	(36.1)	(29.7)	6.4	(35.9)	(30.0)	5.9	(30.2)	(30.0)	0.2	(30.0)	(30.0)	(30.0)
56	**Liquefied Natural Gas Revenue**	14.0 L25	(0.5)	(1.3)	(0.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
57	**Deferral Account Rate Rider Revenue**	14.0 L32	0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	106.5	55.3	28.9
58	**Total Rate Revenue Requirement (Current)**		5,108.1	5,084.0	(24.2)	5,051.6	4,920.4	(131.1)	5,203.6	5,185.7	(17.9)	5,328.5	5,529.4	5,782.6

BC Hydro
F23-F25 RRA

Schedule 3.0
Page 13

Reconciliation of Current and Gross Views
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Summary - Current Rates View													
59	Cost of Energy	Line 5	1,634.8	1,552.5	(82.3)	1,537.7	1,365.8	(171.9)	1,669.8	1,642.3	(27.4)	1,788.4	1,945.5	2,001.0
60	Operating Costs	Line 11	1,195.8	1,207.6	11.8	1,226.7	1,247.9	21.2	1,352.3	1,352.3	(0.0)	1,320.5	1,340.3	1,360.2
61	Provisions & Other	Line 17	162.6	175.0	12.4	138.7	154.0	15.3	165.3	161.7	(3.6)	137.8	135.6	108.6
62	Taxes	Line 20	249.8	249.7	(0.1)	262.2	256.8	(5.4)	263.8	271.4	7.6	283.5	298.3	309.2
63	Amortization	Line 26	1,095.7	1,095.9	0.3	1,119.4	1,120.0	0.6	1,134.2	1,147.4	13.2	1,150.9	1,182.4	1,236.6
64	Finance Charges	Line 33	735.8	735.8	(0.0)	696.0	695.7	(0.2)	454.1	454.8	0.6	556.9	537.7	680.5
65	Return on Equity	Line 37	712.0	704.9	(7.1)	712.0	687.5	(24.5)	712.0	704.4	(7.6)	712.0	712.0	712.0
66	Miscellaneous Revenues	Line 42	(237.5)	(246.0)	(8.5)	(243.6)	(256.1)	(12.6)	(273.5)	(285.0)	(11.5)	(285.7)	(289.2)	(292.8)
67	Inter-Segment Revenue	Line 47	(64.9)	(72.0)	(7.1)	(71.9)	15.0	86.9	(83.5)	(73.0)	10.5	(71.8)	(73.4)	(74.8)
68	Subsidiary Net Income	L51+L52:L54	(339.2)	(288.2)	51.0	(289.7)	(336.1)	(46.4)	(160.7)	(160.7)	(0.0)	(340.6)	(285.1)	(256.7)
69	Other Utilities Revenue	Line 55	(36.1)	(29.7)	6.4	(35.9)	(30.0)	5.9	(30.2)	(30.0)	0.2	(30.0)	(30.0)	(30.0)
70	Liquefied Natural Gas Revenue	Line 56	(0.5)	(1.3)	(0.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
71	Deferral Account Rate Rider Revenue	Line 57	0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	106.5	55.3	28.9
72	Total Rate Revenue Requirement		5,108.1	5,084.0	(24.2)	5,051.6	4,920.4	(131.1)	5,203.6	5,185.7	(17.9)	5,328.5	5,529.4	5,782.6
	Allocation of Current Costs													
73	Generation	3.2 L18	1,695.6	1,757.3	61.7	1,428.9	1,379.5	(49.4)	1,743.2	1,845.6	102.4	1,818.2	1,798.2	2,058.4
74	Transmission	3.4 L22	972.2	983.2	11.0	968.8	986.5	17.7	982.0	940.4	(41.6)	993.6	1,009.2	955.1
75	Distribution	3.5 L16	1,209.2	1,204.0	(5.2)	1,218.8	1,260.2	41.3	1,189.0	1,138.3	(50.8)	1,232.6	1,260.6	1,234.4
76	Customer Care	3.3 L11	1,607.0	1,458.8	(148.1)	1,760.7	1,660.4	(100.3)	1,480.2	1,452.1	(28.2)	1,548.0	1,721.2	1,792.6
77	Business Support	3.1 L18	0.0	0.0	0.0	(0.0)	(0.0)	0.0	(0.0)	0.0	0.0	(0.0)	(0.0)	0.0
78	Subsidiary Net Income	Line 68	(339.2)	(288.2)	51.0	(289.7)	(336.1)	(46.4)	(160.7)	(160.7)	(0.0)	(340.6)	(285.1)	(256.7)
79	Other Utilities Revenue	Line 69	(36.1)	(29.7)	6.4	(35.9)	(30.0)	5.9	(30.2)	(30.0)	0.2	(30.0)	(30.0)	(30.0)
80	Liquefied Natural Gas Revenue	Line 70	(0.5)	(1.3)	(0.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
81	Deferral Account Rate Rider Revenue	Line 71	0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	106.5	55.3	28.9
82	Total Rate Revenue Requirement		5,108.1	5,084.0	(24.2)	5,051.6	4,920.4	(131.1)	5,203.6	5,185.7	(17.9)	5,328.5	5,529.4	5,782.6

BC Hydro
F23-F25 RRA

Schedule 3.1
Page 14

Total Current Costs - Business Support
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Current Operating Costs**	3.6 L6 (Prior F22: 3.6 L55)	438.9	462.5	23.6	465.8	432.6	(33.2)	571.0	569.4	(1.6)	496.7	504.3	512.0
2	**Current Provisions & Other**	5.01 L34	1.3	(6.8)	(8.1)	0.6	25.1	24.5	13.2	11.5	(1.7)	13.7	13.1	11.9
3	**Taxes**	6.0 L30	18.2	17.7	(0.5)	18.7	16.6	(2.1)	18.2	21.6	3.4	21.9	22.3	22.8
4	**Current Amortization**	7.0 L47	202.8	199.4	(3.4)	202.7	200.6	(2.1)	192.8	187.4	(5.3)	213.5	220.7	218.4
5	**Business Support Allocation**	Line 54	(711.8)	(725.4)	(13.6)	(739.9)	(817.0)	(77.1)	(820.6)	(809.9)	10.8	(774.6)	(789.2)	(793.4)
6	**Miscellaneous Revenue**	15.0 L37	(16.1)	(16.4)	(0.2)	(16.4)	(16.3)	0.0	(47.1)	(52.9)	(5.8)	(47.1)	(47.0)	(47.7)
	Internal Allocations													
7	Generation Capitalized Overhead		9.4	9.4	0.0	9.4	9.4	0.0	9.7	9.7	0.0	9.7	9.7	9.7
8	Transmission Capitalized Overhead		16.1	16.1	0.0	16.3	16.3	0.0	16.6	16.6	0.0	16.6	16.6	16.6
9	Distribution Capitalized Overhead		45.5	45.5	0.0	45.7	45.7	0.0	49.2	49.4	0.2	49.9	49.9	50.1
10	Generation RSRA Write-off				0.0			0.0			0.0			
11	Transmission RSRA Write-off				0.0			0.0			0.0			
12	Distribution RSRA Write-off				0.0			0.0			0.0			
13	Adj to align with prior approved RRA				0.0			0.0			0.0			
14	Total		71.0	71.0	0.0	71.4	71.4	0.0	75.5	75.7	0.2	76.2	76.2	76.4
	Inter-Segment Revenue													
15	Powerex - Business Support Allocation		(2.9)	(2.9)	0.0	(2.9)	(2.9)	0.0	(2.9)	(2.9)	0.0	(0.3)	(0.3)	(0.4)
16	Mark to Market Losses (Gains)		(1.4)	0.8	2.2	0.0	90.0	90.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Total		(4.3)	(2.1)	2.2	(2.9)	87.1	90.0	(2.9)	(2.9)	0.0	(0.3)	(0.3)	(0.4)
18	**Total**		0.0	0.0	0.0	(0.0)	(0.0)	0.0	(0.0)	0.0	0.0	(0.0)	(0.0)	0.0
	Internal Allocation by Function:													
	Insurance													
19	Generation		4.3	4.3	0.0	4.3	4.3	0.0	4.1	4.1	0.0	9.6	9.9	10.2
20	Transmission		2.4	2.4	0.0	2.4	2.4	0.0	4.4	4.4	0.0	3.2	3.3	3.4
21	Distribution		2.6	2.6	0.0	2.6	2.6	0.0	5.6	5.6	0.0	4.1	4.2	4.3
22	Customer Care		0.5	0.5	0.0	0.5	0.5	0.0	1.2	1.2	0.0	0.3	0.3	0.3
23	Total		9.7	9.7	0.0	9.7	9.7	0.0	15.2	15.2	0.0	17.2	17.7	18.2
	Non-Current/Current Pension Costs													
24	Generation		24.5	24.5	0.0	24.9	24.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	Transmission		25.7	25.7	0.0	25.5	25.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Distribution		25.9	25.9	0.0	25.7	25.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Customer Care		10.0	10.0	0.0	10.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Total		86.1	86.1	0.0	86.1	86.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0

BC Hydro
F23-F25 RRA

Schedule 3.1
Page 15

Total Current Costs - Business Support
($ million)

Line	Reference Column	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Fleet/MMBU												
29	Generation	8.5	8.5	0.0	8.6	8.6	0.0	9.3	9.4	0.0	9.5	9.8	10.0
30	Transmission	23.3	23.3	0.0	23.6	23.6	0.0	22.1	22.2	0.0	25.3	25.9	26.4
31	Distribution	54.6	54.6	0.0	55.4	55.4	0.0	62.0	62.1	0.0	62.7	64.2	65.4
32	Customer Care	1.3	1.3	0.0	1.3	1.3	0.0	1.3	1.3	0.0	1.1	1.1	1.2
33	Total	87.6	87.6	0.0	89.0	89.0	0.0	94.8	94.9	0.1	98.6	101.1	102.9
	Total Direct Assignments												
34	Generation	37.3	37.3	0.0	37.8	37.8	0.0	13.4	13.4	0.0	19.1	19.7	20.1
35	Transmission	51.3	51.3	0.0	51.5	51.5	0.0	26.5	26.5	0.0	28.6	29.2	29.7
36	Distribution	83.1	83.1	0.0	83.7	83.7	0.0	67.6	67.7	0.0	66.8	68.4	69.7
37	Customer Care	11.8	11.8	0.0	11.8	11.8	0.0	2.5	2.5	0.0	1.4	1.5	1.5
38	Business Support	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Total	183.4	183.4	0.0	184.8	184.8	0.0	110.1	110.1	0.1	115.9	118.7	121.1
	Allocators for Balance - %												
40	Generation	28.5%	28.5%	-	28.9%	28.9%	-	29.0%	29.0%	-	27.6%	27.6%	27.6%
41	Transmission	28.8%	28.8%	-	28.5%	28.5%	-	29.9%	29.9%	-	30.4%	30.4%	30.4%
42	Distribution	31.2%	31.2%	-	30.9%	30.9%	-	32.4%	32.4%	-	33.0%	33.0%	32.9%
43	Customer Care	11.6%	11.6%	-	11.6%	11.6%	-	8.7%	8.7%	-	9.1%	9.1%	9.0%
44	Total	100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%	100.0%
	Allocation of Balance												
45	Generation	150.6	154.4	3.9	160.7	183.0	22.3	206.2	203.0	(3.1)	181.5	184.8	185.9
46	Transmission	152.0	155.9	3.9	158.5	180.5	22.0	212.5	209.3	(3.2)	200.4	203.9	204.3
47	Distribution	164.6	168.8	4.2	171.6	195.4	23.8	230.2	226.7	(3.5)	217.1	220.9	221.4
48	Customer Care	61.2	62.8	1.6	64.4	73.3	8.9	61.6	60.7	(0.9)	59.7	60.8	60.8
49	Total	528.4	541.9	13.6	555.1	632.2	77.1	710.6	699.8	(10.8)	658.7	670.5	672.4
	Total Business Support Allocation												
50	Generation	187.8	191.7	3.9	198.5	220.8	22.3	219.6	216.5	(3.1)	200.6	204.4	206.0
51	Transmission	203.3	207.2	3.9	209.9	232.0	22.0	239.1	235.8	(3.2)	229.0	233.2	234.1
52	Distribution	247.7	251.9	4.2	255.3	279.1	23.8	297.9	294.4	(3.5)	283.9	289.3	291.1
53	Customer Care	73.0	74.6	1.6	76.2	85.1	8.9	64.1	63.2	(0.9)	61.1	62.3	62.3
54	Total	711.8	725.4	13.6	739.9	817.0	77.1	820.6	809.9	(10.8)	774.6	789.2	793.4

BC Hydro
F23-F25 RRA

Schedule 3.2
Page 16

Total Current Costs - Generation
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
Line	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Cost of Energy**	4.0 L81	229.8	293.4	63.7	(16.3)	(84.5)	(68.2)	378.1	377.8	(0.3)	413.8	397.3	382.6
2	**Current Operating Costs**	3.6 L2 (Prior F22: 3.6 L51)	206.5	195.2	(11.3)	210.8	217.2	6.3	221.5	343.9	122.4	228.4	231.9	238.3
3	**Current Provisions & Other**	5.01 L30	51.1	55.0	3.9	24.8	23.4	(1.3)	15.1	15.0	(0.1)	18.6	11.8	14.4
4	**Taxes**	6.0 L26	44.3	44.2	(0.0)	46.3	45.2	(1.1)	46.1	46.1	0.1	47.3	48.4	48.9
5	**Current Amortization**	7.0 L43	353.9	355.6	1.8	363.5	366.1	2.6	375.7	365.4	(10.4)	370.9	380.8	415.4
6	**Current Finance Charges**	8.0 L48	338.4	339.9	1.5	319.6	320.5	0.9	207.7	206.9	(0.8)	251.6	241.0	387.7
7	**Return on Equity**	9.0 L39	327.5	325.6	(1.9)	326.9	316.7	(10.2)	325.7	320.5	(5.2)	321.7	319.1	405.6
8	**Business Support Allocation**	3.1 L50	187.8	191.7	3.9	198.5	220.8	22.3	219.6	216.5	(3.1)	200.6	204.4	206.0
9	**Miscellaneous Revenue**	15.0 L8	(1.9)	(2.5)	(0.6)	(1.9)	(2.6)	(0.7)	(2.2)	(2.1)	0.1	(2.1)	(2.0)	(1.8)
	Internal Allocations													
10	GRTA Allocation	3.4 L9	43.3	43.3	0.0	43.3	43.3	0.0	43.3	43.3	0.0	54.0	54.7	52.1
11	Generation Real Time Dispatch	3.4 L10	2.4	2.4	0.0	2.4	2.4	0.0	3.0	3.0	(0.0)	5.6	4.4	4.5
12	Generation Ancillary Services	3.4 L14	(2.8)	(2.1)	0.8	(2.8)	(2.8)	0.0	(2.5)	(2.6)	(0.2)	(2.6)	(2.6)	(2.6)
13	Generation Capitalized Overhead	3.1 L7	(9.4)	(9.4)	0.0	(9.4)	(9.4)	0.0	(9.7)	(9.7)	0.0	(9.7)	(9.7)	(9.7)
14	Generation RSRA Write-off	3.1 L10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Waneta 2/3 Lease revenue from Teck	3.3 L8	(75.2)	(75.2)	(0.0)	(76.7)	(76.7)	(0.0)	(78.2)	(78.2)	0.0	(79.8)	(81.4)	(83.0)
16	Adj to align with prior approved RRA				0.0			0.0			0.0			
17	Total		(41.8)	(41.0)	0.8	(43.3)	(43.2)	0.0	(44.1)	(44.2)	(0.2)	(32.5)	(34.5)	(38.7)
18	**Total**		1,695.6	1,757.3	61.7	1,428.9	1,379.5	(49.4)	1,743.2	1,845.6	102.4	1,818.2	1,798.2	2,058.4

BC Hydro
F23-F25 RRA

Schedule 3.3
Page 17

Total Current Costs - Customer Care
($ million)

Line	Column	Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Cost of Energy**	4.0 L83	1,405.0	1,259.0	(145.9)	1,554.0	1,450.3	(103.7)	1,291.7	1,264.5	(27.1)	1,374.6	1,548.3	1,618.3
2	**Current Operating Costs**	3.6 L5 (Prior F22: 3.6 L54)	78.7	75.0	(3.7)	79.6	73.0	(6.6)	68.9	68.8	(0.1)	85.7	86.6	87.7
3	**Current Provisions & Other**	5.01 L33	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
4	**Taxes**	6.0 L29	0.6	0.9	0.3	0.6	0.8	0.2	0.8	0.8	(0.0)	0.8	0.8	0.9
5	**Current Amortization**	7.0 L46	88.9	88.9	0.0	90.1	90.1	0.0	90.6	90.6	(0.0)	61.4	59.5	60.3
6	**Business Support Allocation**	3.1 L53	73.0	74.6	1.6	76.2	85.1	8.9	64.1	63.2	(0.9)	61.1	62.3	62.3
7	**Miscellaneous Revenue**	15.0 L31	(114.5)	(114.8)	(0.3)	(116.4)	(115.5)	0.9	(114.1)	(114.1)	0.1	(115.5)	(117.6)	(119.8)
	Internal Allocations													
8	Waneta 2/3 Lease revenue from Teck	15.0 L26	75.2	75.2	0.0	76.7	76.7	0.0	78.2	78.2	0.0	79.8	81.4	83.0
9	Adj to align with prior approved RRA				0.0			0.0			0.0			
10	Total		75.2	75.2	0.0	76.7	76.7	0.0	78.2	78.2	0.0	79.8	81.4	83.0
11	**Total**		1,607.0	1,458.8	(148.1)	1,760.7	1,660.4	(100.3)	1,480.2	1,452.1	(28.2)	1,548.0	1,721.2	1,792.6

BC Hydro
F23-F25 RRA

Schedule 3.4
Page 18

Total Current Costs - Transmission
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Current Operating Costs**	3.6 L3 (Prior F22: 3.6 L52)	219.4	206.4	(13.1)	220.5	242.0	21.5	247.2	209.4	(37.8)	263.4	266.3	263.6
2	**Current Provisions & Other**	5.01 L31	33.8	48.7	14.9	37.3	31.1	(6.2)	62.8	61.5	(1.3)	53.6	59.2	32.8
3	**Taxes**	6.0 L27	157.6	158.4	0.8	163.7	164.7	1.0	167.0	172.6	5.6	179.5	187.9	193.2
4	**Current Amortization**	7.0 L44	233.5	234.4	0.8	236.1	235.8	(0.3)	239.2	264.7	25.5	256.5	262.1	271.7
5	**Current Finance Charges**	8.0 L49	243.9	243.0	(0.9)	227.6	227.9	0.2	148.3	149.1	0.8	181.5	174.9	172.9
6	**Return on Equity**	9.0 L40	236.1	232.8	(3.2)	232.9	225.2	(7.7)	232.5	231.0	(1.5)	232.1	231.5	180.9
7	**Business Support Allocation**	3.1 L51	203.3	207.2	3.9	209.9	232.0	22.0	239.1	235.8	(3.2)	229.0	233.2	234.1
8	**Miscellaneous Revenue**	15.0 L15	(46.1)	(46.4)	(0.3)	(46.8)	(52.6)	(5.8)	(41.4)	(44.0)	(2.6)	(45.5)	(43.6)	(43.2)
	Internal Allocations:													
9	GRTA Allocation		**(43.3)**	**(43.3)**	0.0	**(43.3)**	**(43.3)**	0.0	**(43.3)**	**(43.3)**	0.0	**(54.0)**	**(54.7)**	**(52.1)**
10	Generation Real Time Dispatch		**(2.4)**	**(2.4)**	(0.0)	**(2.4)**	**(2.4)**	(0.0)	**(3.0)**	**(3.0)**	0.0	**(5.6)**	**(4.4)**	**(4.5)**
11	Distribution Real Time Dispatch		**(20.6)**	**(20.8)**	(0.2)	**(21.0)**	**(21.3)**	(0.4)	**(25.7)**	**(25.6)**	0.1	**(24.0)**	**(25.4)**	**(25.8)**
12	SDA Allocation to Distribution		**(125.6)**	**(127.0)**	(1.4)	**(127.4)**	**(129.0)**	(1.5)	**(149.3)**	**(156.7)**	(7.4)	**(154.4)**	**(155.9)**	**(148.1)**
13	PTP Allocation to Distribution	L21 + L68	(43.6)	(23.9)	19.7	(36.0)	(38.0)	(2.0)	3.3	(27.0)	(30.4)	(32.9)	(34.7)	(31.7)
14	Generation Ancillary Services		**2.8**	**2.1**	(0.8)	**2.8**	**2.8**	0.0	**2.5**	**2.6**	0.2	**2.6**	**2.6**	**2.6**
15	Transmission Capitalized Overhead	3.1 L8	(16.1)	(16.1)	0.0	(16.3)	(16.3)	0.0	(16.6)	(16.6)	0.0	(16.6)	(16.6)	(16.6)
16	Transmission RSRA Write-off	3.1 L11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Adj to align with prior approved RRA				0.0			0.0			0.0			
18	Total		(248.7)	(231.3)	17.4	(243.5)	(247.4)	(4.0)	(232.1)	(269.6)	(37.6)	(284.8)	(289.2)	(276.3)
	Inter-Segment Revenue													
19	Powerex PTP Charges		**(41.5)**	**(49.8)**	(8.3)	**(34.0)**	**(41.7)**	(7.8)	**(34.4)**	**(38.2)**	(3.8)	**(39.0)**	**(39.8)**	**(40.6)**
20	BC Hydro PTP Charges		**(19.1)**	**(20.1)**	(1.0)	**(35.0)**	**(30.4)**	4.7	**(46.3)**	**(31.9)**	14.3	**(32.5)**	**(33.2)**	**(33.9)**
21	Total		(60.6)	(69.9)	(9.3)	(69.0)	(72.1)	(3.1)	(80.6)	(70.1)	10.5	(71.5)	(73.0)	(74.5)
22	**Total Current Costs**		972.2	983.2	11.0	968.8	986.5	17.7	982.0	940.4	(41.6)	993.6	1,009.2	955.1
	Transmission Revenue Requirement													
23	Total Current Costs	Line 22	972.2	983.2	11.0	968.8	986.5	17.7	982.0	940.4	(41.6)	993.6	1,009.2	955.1
24	Adj to offset re-org impact				0.0			0.0			0.0			
25	Adj. Total Current Costs		972.2	983.2	11.0	968.8	986.5	17.7	982.0	940.4	(41.6)	993.6	1,009.2	955.1
26	PTP Allocation to Distribution	Line 13	43.6	23.9	(19.7)	36.0	38.0	2.0	(3.3)	27.0	30.4	32.9	34.7	31.7
27	Inter-Segment Revenue	Line 21	60.6	69.9	9.3	69.0	72.1	3.1	80.6	70.1	(10.5)	71.5	73.0	74.5
28	External OATT Revenue	Line 74	15.9	10.7	(5.2)	15.9	14.1	(1.8)	11.1	11.6	0.5	12.2	12.3	11.9
29	Total TRR		1,092.3	1,087.7	(4.7)	1,089.6	1,110.7	21.1	1,070.4	1,049.1	(21.3)	1,110.2	1,129.3	1,073.2

BC Hydro
F23-F25 RRA

Schedule 3.4
Page 19

Total Current Costs - Transmission
($ million)

			F2020			F2021			F2022			F2023	F2024	F2025
		Reference	Decision	Actual	Diff	Decision	Actual	Diff	Decision	Forecast	Diff	Plan	Plan	Plan
Line	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	NITS Charge to BC Hydro													
30	Adj. Total Current Costs	Line 25	972.2			968.8			982.0	940.4		993.6	1,009.2	955.1
31	Internal Ancillary Services	Line 36	0.0			0.0			0.0	0.0		0.0	0.0	0.0
32	Internal Scheduling & Dispatch	Line 38	(3.8)			(3.9)			(3.7)	(4.4)		(4.2)	(4.4)	(4.5)
33	Total		968.4	928.2	(40.2)	964.8	982.9	18.1	978.3	935.9	(42.4)	989.4	1,004.8	950.6
34	NITS Monthly Rate	Line 33 / 12	80.7	77.4		80.4	81.9		81.5	78.0		82.5	83.7	79.2
	Long-Term PTP Rate													
35	Total TRR	Line 29	1,092.3			1,089.6			1,070.4	1,049.1		1,110.2	1,129.3	1,073.2
36	Internal Ancillary Services		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	External Ancillary Services		(2.8)	(2.1)	0.8	(2.8)	(3.5)	(0.6)	(2.5)	(2.6)	(0.2)	(2.6)	(2.6)	(2.6)
38	Internal Scheduling & Dispatch		(3.8)	(3.5)	0.4	(3.9)	(4.0)	(0.1)	(3.7)	(4.4)	(0.7)	(4.2)	(4.4)	(4.5)
39	External Scheduling & Dispatch		(0.2)	(0.1)	0.1	(0.2)	(0.2)	0.0	(0.2)	(0.2)	(0.0)	(0.2)	(0.2)	(0.2)
40	Total		1,085.4			1,082.7			1,064.0	1,041.8		1,103.1	1,122.0	1,065.8
41	Maximum Supply (MW)		13,279	13,279		13,279	13,279		13,596	13,596		13,337	13,337	13,337
42	Long-Term Firm PTP Rate ($/MW/year)		81,741	78,490		81,531	81,988		78,262	76,628		82,713	84,129	79,914
	Maximum Price for Short-Term Firm and Non-Firm (per MW of Reserved Capacity)													
43	Monthly ($/MW/month)		6,811.71	6,540.80		6,794.28	6,832.35		6,521.81	6,385.65		6,892.77	7,010.73	6,659.52
44	Weekly ($/MW/week)		1,571.93	1,509.42		1,567.91	1,576.70		1,505.03	1,473.61		1,590.64	1,617.86	1,536.81
45	Daily ($/MW/day)		223.95	215.04		223.37	224.63		214.42	209.94		226.61	230.49	218.94
46	Hourly ($/MW/hour)		9.33	8.96		9.31	9.36		8.93	8.75		9.44	9.60	9.12
	Scheduling Fee													
47	Scheduling, Control & Dispatch	L38 + L39	4.1	3.6		4.1	4.2		3.9	4.6		4.4	4.6	4.7
48	Total Volume (GWh)		29,388	27,093		29,773	29,196		25,496	31,079		31,871	32,720	33,546
49	Scheduling Fee ($/MWh)	L47 / L48	0.138	0.133		0.139	0.144		0.152	0.149		0.138	0.141	0.140
	Long-Term PTP Volumes (GWh)													
50	Internal		8,567	9,242	675	8,567	8,427	(141)	7,577	7,577	0	7,577	7,577	7,577
51	External		1,314	878	(436)	1,314	876	(438)	876	876	0	876	876	876
52	Total		9,881	10,121	239	9,881	9,303	(579)	8,453	8,453	0	8,453	8,453	8,453
	Long-Term PTP Revenue													
53	Internal	L46 * L50	79.9	82.8	2.9	79.8	78.4	(1.3)	67.7	66.3	(1.4)	71.5	72.8	69.1
54	External	L46 * L51	12.3	7.9	(4.4)	12.2	8.6	(3.6)	7.8	7.7	(0.2)	8.3	8.4	8.0
55	Total		92.2	90.7	(1.5)	92.0	87.1	(4.9)	75.5	73.9	(1.6)	79.8	81.2	77.1
	Long-Term PTP Average Price ($/MWh)													
56	Internal	L53 / L50	9.33	8.96	(0.37)	9.31	9.31	(0.00)	8.93	8.75	(0.19)	9.44	9.60	9.12
57	External	L54 / L51	9.33	8.96	(0.37)	9.31	9.87	0.56	8.93	8.75	(0.19)	9.44	9.60	9.12
58	Total	L55 / L52	9.33	8.96	(0.37)	9.31	9.36	0.05	8.93	8.75	(0.19)	9.44	9.60	9.12

BC Hydro
F23-F25 RRA

Schedule 3.4
Page 20

Total Current Costs - Transmission
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Short-Term PTP Volumes (GWh)													
59	Internal		**9,700**	**3,848**	(5,852)	**10,085**	**9,509**	(575)	**3,848**	**12,347**	8,499	**13,140**	**13,989**	**14,814**
60	External		**240**	**170**	(70)	**240**	**536**	296	**240**	**430**	190	**430**	**430**	**430**
61	Total		9,940	4,017	(5,923)	10,325	10,045	(280)	4,088	12,777	8,689	13,570	14,419	15,244
	Short-Term PTP Revenue													
62	Internal		**24.2**	**11.0**	(13.3)	**25.2**	**31.7**	6.4	**9.6**	**30.9**	21.2	**32.8**	**35.0**	**37.0**
63	External		**0.6**	**0.6**	(0.0)	**0.6**	**1.8**	1.2	**0.6**	**1.1**	0.5	**1.1**	**1.1**	**1.1**
64	Total		24.8	11.5	(13.3)	25.8	33.5	7.6	10.2	31.9	21.7	33.9	36.0	38.1
	Short-Term PTP Average Price ($/MWh)													
65	Internal	L62 / L59	2.50	2.85	0.35	2.50	3.33	0.83	2.50	2.50	0.00	2.50	2.50	2.50
66	External	L63 / L60	2.50	3.46	0.96	2.50	3.35	0.85	2.50	2.50	0.00	2.50	2.50	2.50
67	Total	L64 / L61	2.50	2.87	0.37	2.50	3.33	0.83	2.50	2.50	0.00	2.50	2.50	2.50
	Total PTP Revenue													
68	Internal	L53 + L62	104.2	93.8	(10.4)	105.0	110.1	5.1	77.3	97.2	19.8	104.4	107.7	106.2
69	External	L54 + L63	12.9	8.5	(4.4)	12.8	10.4	(2.4)	8.4	8.7	0.3	9.3	9.5	9.1
70	Total		117.0	102.2	(14.8)	117.8	120.5	2.7	85.7	105.9	20.1	113.7	117.2	115.2
	Total External OATT Revenue													
71	Total External PTP	Line 69	12.9	8.5	(4.4)	12.8	10.4	(2.4)	8.4	8.7	0.3	9.3	9.5	9.1
72	External Ancillary Services	Line 37	2.8	2.1	(0.8)	2.8	3.5	0.6	2.5	2.6	0.2	2.6	2.6	2.6
73	External Scheduling & Dispatch	Line 39	0.2	0.1	(0.1)	0.2	0.2	(0.0)	0.2	0.2	0.0	0.2	0.2	0.2
74	Total		15.9	10.7	(5.2)	15.9	14.1	(1.8)	11.1	11.6	0.5	12.2	12.3	11.9

BC Hydro
F23-F25 RRA

Schedule 3.5
Page 21

Total Current Costs - Distribution
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Current Operating Costs**	3.6 L4 (Prior F22: 3.6 L53)	252.2	268.5	16.3	250.0	283.1	33.1	243.6	160.8	(82.8)	246.4	251.1	258.7
2	**Current Provisions & Other**	5.01 L32	76.4	78.0	1.6	76.1	74.3	(1.7)	74.2	73.7	(0.5)	51.9	51.5	49.6
3	**Taxes**	6.0 L28	29.1	28.6	(0.6)	32.9	29.6	(3.3)	31.7	30.3	(1.5)	34.0	39.0	43.5
4	**Current Amortization**	7.0 L45	216.5	217.6	1.1	227.0	227.5	0.5	235.9	239.3	3.4	248.5	259.3	270.9
5	**Current Finance Charges**	8.0 L50	153.4	152.8	(0.6)	148.8	147.4	(1.4)	98.1	98.8	0.7	123.8	121.9	120.0
6	**Return on Equity**	9.0 L41	148.4	146.4	(2.0)	152.2	145.6	(6.6)	153.8	153.0	(0.8)	158.3	161.4	125.5
7	**Business Support Allocation**	3.1 L52	247.7	251.9	4.2	255.3	279.1	23.8	297.9	294.4	(3.5)	283.9	289.3	291.1
8	**Miscellaneous Revenue**	15.0 L19	(58.9)	(66.0)	(7.1)	(62.0)	(69.1)	(7.1)	(68.6)	(71.9)	(3.2)	(75.5)	(79.0)	(80.3)
	Internal Allocations													
9	Distribution Real Time Dispatch	3.4 L11	20.6	20.8	0.2	21.0	21.3	0.4	25.7	25.6	(0.1)	24.0	25.4	25.8
10	SDA Allocation from Transmission	3.4 L12	125.6	127.0	1.4	127.4	129.0	1.5	149.3	156.7	7.4	154.4	155.9	148.1
11	PTP Allocation to Distribution	3.4 L13	43.6	23.9	(19.7)	36.0	38.0	2.0	(3.3)	27.0	30.4	32.9	34.7	31.7
12	Distribution Capitalized Overhead	3.1 L9	(45.5)	(45.5)	0.0	(45.7)	(45.7)	0.0	(49.2)	(49.4)	(0.2)	(49.9)	(49.9)	(50.1)
13	Distribution RSRA Write-off	3.1 L12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Adj to align with prior approved RRA				0.0			0.0			0.0			
15	Total		144.3	126.2	(18.1)	138.7	142.6	3.9	122.4	159.9	37.5	161.4	166.1	155.5
16	**Total**		1,209.2	1,204.0	(5.2)	1,218.8	1,260.2	41.3	1,189.0	1,138.3	(50.8)	1,232.6	1,260.6	1,234.4

BC Hydro
F23-F25 RRA

Schedule 3.6
Page 22

Total Current Operating Costs and Provisions
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Total Current Operating Costs**	5.0 L55	1,195.8	1,207.6	11.8	1,226.7	1,247.9	21.2	1,352.3	1,352.3	(0.0)	1,320.5	1,340.3	1,360.2
	Total Internal Allocation													
2	Generation		(307.7)	(304.6)	3.1	(311.8)	(323.3)	(11.5)	(345.5)	(343.9)	1.6	(228.4)	(231.9)	(238.3)
3	Transmission		(188.7)	(188.4)	0.4	(189.3)	(194.7)	(5.4)	(206.5)	(209.4)	(2.9)	(263.4)	(266.3)	(263.6)
4	Distribution		(190.9)	(196.1)	(5.2)	(189.1)	(207.4)	(18.3)	(160.5)	(160.8)	(0.3)	(246.4)	(251.1)	(258.7)
5	Customer Care		(69.8)	(67.4)	2.4	(70.4)	(65.0)	5.4	(68.9)	(68.8)	0.1	(85.7)	(86.6)	(87.7)
6	Business Support		(438.7)	(451.2)	(12.5)	(466.1)	(457.4)	8.7	(570.9)	(569.4)	1.5	(496.7)	(504.3)	(512.0)
7	Total		(1,195.8)	(1,207.6)	(11.8)	(1,226.7)	(1,247.9)	(21.2)	(1,352.3)	(1,352.3)	0.0	(1,320.5)	(1,340.3)	(1,360.2)
8	**Total**		0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
	Total Internal Allocation by BG													
	Integrated Planning													
9	Generation	3.7 L2	(196.3)	(195.1)	1.1	(198.4)	(209.0)	(10.6)	(234.1)	(231.8)	2.3	(113.6)	(116.2)	(121.3)
10	Transmission	3.7 L3	(86.5)	(85.6)	0.9	(87.4)	(90.6)	(3.1)	(98.4)	(101.4)	(3.0)	(154.0)	(155.4)	(160.1)
11	Distribution	3.7 L4	(11.2)	(12.5)	(1.3)	(10.5)	(13.1)	(2.6)	(14.9)	(15.1)	(0.2)	(89.1)	(92.8)	(98.3)
12	Customer Care	3.7 L5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Business Support	3.7 L6	(4.4)	(4.5)	(0.1)	(4.8)	(5.0)	(0.3)	(5.5)	(5.6)	(0.1)	(10.8)	(10.2)	(10.7)
14	Total	3.7 L7	(298.4)	(297.8)	0.6	(301.1)	(317.7)	(16.6)	(353.0)	(353.9)	(0.9)	(367.5)	(374.6)	(390.4)
	Capital Infrastructure Project Delivery													
15	Generation	3.8 L2	(53.2)	(52.5)	0.6	(54.4)	(52.9)	1.5	(49.4)	(49.0)	0.4	(48.8)	(49.0)	(44.0)
16	Transmission	3.8 L3	(32.0)	(31.6)	0.5	(30.8)	(30.2)	0.6	(33.4)	(33.3)	0.2	(34.1)	(34.3)	(23.1)
17	Distribution	3.8 L4	(5.6)	(5.5)	0.1	(5.4)	(5.7)	(0.2)	(6.1)	(6.0)	0.0	(6.1)	(6.6)	(6.6)
18	Customer Care	3.8 L5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Business Support	3.8 L6	(29.2)	(29.8)	(0.6)	(29.4)	(30.3)	(1.0)	(29.8)	(29.8)	0.0	(30.0)	(30.2)	(30.5)
20	Total	3.8 L7	(120.0)	(119.5)	0.5	(120.0)	(119.1)	0.9	(118.7)	(118.1)	0.6	(119.0)	(120.2)	(104.2)
	Operations													
21	Generation	3.9 L2	(58.3)	(56.9)	1.4	(59.0)	(61.4)	(2.4)	(61.9)	(63.1)	(1.1)	(66.0)	(66.8)	(67.3)
22	Transmission	3.9 L3	(69.3)	(70.3)	(1.0)	(70.2)	(73.1)	(2.9)	(73.6)	(73.7)	(0.1)	(74.3)	(75.2)	(78.6)
23	Distribution	3.9 L4	(144.6)	(148.4)	(3.8)	(144.7)	(160.0)	(15.3)	(112.9)	(113.1)	(0.2)	(122.8)	(123.6)	(125.8)
24	Customer Care	3.9 L5	(1.4)	(1.9)	(0.5)	(1.4)	0.0	1.4	0.0	0.0	0.0	0.0	0.0	0.0
25	Business Support	3.9 L6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Total	3.9 L7	(273.6)	(277.5)	(3.9)	(275.3)	(294.5)	(19.2)	(248.5)	(249.9)	(1.4)	(263.0)	(265.5)	(271.8)
	Safety													
27	Generation	3.10 L2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Transmission	3.10 L3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Distribution	3.10 L4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Customer Care	3.10 L5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Business Support	3.10 L6	(57.8)	(56.4)	1.4	(58.5)	(63.7)	(5.2)	(68.3)	(66.2)	2.1	(66.0)	(66.5)	(68.4)
32	Total	3.10 L7	(57.8)	(56.4)	1.4	(58.5)	(63.7)	(5.2)	(68.3)	(66.2)	2.1	(66.0)	(66.5)	(68.4)

BC Hydro
F23-F25 RRA

Schedule 3.6
Page 23

Total Current Operating Costs and Provisions
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
Column			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Finance, Technology, Supply Chain													
33	Generation	3.11 L2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Transmission	3.11 L3	(0.8)	(0.8)	0.0	(0.8)	(0.8)	0.0	(1.0)	(1.0)	0.0	(1.0)	(1.0)	(1.0)
35	Distribution	3.11 L4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Customer Care	3.11 L5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Business Support	3.11 L6	(261.8)	(264.2)	(2.5)	(263.9)	(276.5)	(12.5)	(298.1)	(299.0)	(0.9)	(308.8)	(315.3)	(319.5)
38	Total	3.11 L7	(262.6)	(265.1)	(2.5)	(264.8)	(277.3)	(12.5)	(299.1)	(300.0)	(0.9)	(309.8)	(316.3)	(320.5)
	People, Customer, Corporate Affairs													
39	Generation	3.12 L2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	Transmission	3.12 L3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.4)	(0.8)
41	Distribution	3.12 L4	(29.4)	(29.6)	(0.2)	(28.5)	(28.6)	(0.2)	(26.6)	(26.6)	0.0	(28.5)	(28.1)	(27.9)
42	Customer Care	3.12 L5	(68.3)	(65.5)	2.9	(69.0)	(65.0)	4.0	(68.9)	(68.8)	0.1	(85.7)	(86.6)	(87.7)
43	Business Support	3.12 L6	(19.0)	(21.6)	(2.5)	(19.3)	(27.4)	(8.1)	(28.2)	(28.7)	(0.5)	(28.1)	(28.7)	(29.4)
44	Total	3.12 L7	(116.8)	(116.6)	0.2	(116.7)	(121.0)	(4.3)	(123.7)	(124.0)	(0.4)	(142.4)	(143.8)	(145.7)
	Other													
45	Generation	3.13 L6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(5.6)
46	Transmission	3.13 L7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
47	Distribution	3.13 L8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	Customer Care	3.13 L9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	Business Support	3.13 L10	(66.5)	(74.7)	(8.2)	(90.2)	(54.5)	35.8	(141.0)	(140.2)	0.9	(52.9)	(53.3)	(53.6)
50	Total	3.13 L11	(66.5)	(74.7)	(8.2)	(90.2)	(54.5)	35.8	(141.0)	(140.2)	0.9	(52.9)	(53.3)	(59.2)
	Total Internal Allocation (Prior Approved RRA)													
51	Generation		**(257.6)**	**(250.2)**		**(235.6)**	**(240.6)**		**(221.5)**					
52	Transmission		**(253.2)**	**(255.1)**		**(257.8)**	**(273.2)**		**(247.2)**					
53	Distribution		**(328.7)**	**(346.6)**		**(326.0)**	**(357.4)**		**(243.6)**					
54	Customer Care		**(78.7)**	**(75.0)**		**(79.6)**	**(73.0)**		**(68.9)**					
55	Business Support		**(440.3)**	**(455.8)**		**(466.4)**	**(457.7)**		**(571.0)**					
56	Total		(1,358.4)	(1,382.6)		(1,365.4)	(1,401.8)							

BC Hydro
F23-F25 RRA

Schedule 3.7
Page 24

Integrated Planning
Current Operating Costs and Provisions ($ million)

			F2020			F2021			F2022			F2023	F2024	F2025
		Reference	Decision	Actual	Diff	Decision	Actual	Diff	Decision	Forecast	Diff	Plan	Plan	Plan
Line	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Current Operating Costs**	5.0 L46	298.4	297.8	(0.6)	301.1	317.7	16.6	353.0	353.9	0.9	367.5	374.6	390.4
	Internal Allocations													
2	Generation	Line 16	(196.3)	(195.1)	1.1	(198.4)	(209.0)	(10.6)	(234.1)	(231.8)	2.3	(113.6)	(116.2)	(121.3)
3	Transmission	Line 23	(86.5)	(85.6)	0.9	(87.4)	(90.6)	(3.1)	(98.4)	(101.4)	(3.0)	(154.0)	(155.4)	(160.1)
4	Distribution	Line 30	(11.2)	(12.5)	(1.3)	(10.5)	(13.1)	(2.6)	(14.9)	(15.1)	(0.2)	(89.1)	(92.8)	(98.3)
5	Customer Care				0.0			0.0			0.0			
6	Business Support	Line 35	(4.4)	(4.5)	(0.1)	(4.8)	(5.0)	(0.3)	(5.5)	(5.6)	(0.1)	(10.8)	(10.2)	(10.7)
7	Total		(298.4)	(297.8)	0.6	(301.1)	(317.7)	(16.6)	(353.0)	(353.9)	(0.9)	(367.5)	(374.6)	(390.4)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:													
	Generation													
9	Energy Planning & Analytics		1.0	1.0	0.0	1.0	1.1	0.1	1.1	1.1	(0.0)	1.0	1.1	1.1
10	Dam Safety	5.1 L2	10.2	9.8	(0.4)	10.3	10.4	0.0	11.4	11.4	0.0	11.2	11.4	11.9
11	Asset Planning		161.8	163.7	2.0	163.4	171.4	8.0	195.7	196.3	0.6	79.2	81.0	83.3
12	Engineering Design		7.9	7.7	(0.2)	8.0	7.1	(0.9)	7.5	7.4	(0.1)	6.5	6.6	6.8
13	Engineering Services		2.7	2.6	(0.1)	2.8	3.5	0.8	4.4	4.5	0.1	4.6	4.8	4.9
14	Waneta 2/3		5.7	5.4	(0.3)	5.9	5.8	(0.0)	6.1	6.1	0.0	5.9	6.1	6.3
15	Business Support		7.0	4.9	(2.1)	7.1	9.7	2.6	8.1	5.1	(3.0)	5.2	5.3	7.1
16	Subtotal		196.3	195.1	(1.1)	198.4	209.0	10.6	234.1	231.8	(2.3)	113.6	116.2	121.3
	Transmission													
17	Energy Planning & Analytics		1.3	1.3	0.0	1.3	1.4	0.1	1.3	1.3	(0.0)	1.3	1.3	1.4
18	Asset Planning		60.2	60.9	0.7	60.8	63.7	3.0	72.8	73.0	0.2	123.7	125.9	127.9
19	Interconnections and Shared Assets		5.1	6.4	1.3	5.2	7.6	2.3	7.3	8.2	0.9	9.2	8.4	8.4
20	Engineering Design		8.8	8.6	(0.2)	8.9	7.9	(1.0)	8.4	8.3	(0.1)	9.6	9.5	9.8
21	Engineering Services		2.4	2.3	(0.1)	2.4	3.1	0.7	3.8	3.9	0.1	3.3	3.3	3.4
22	Business Support		8.8	6.2	(2.6)	8.9	6.9	(1.9)	4.8	6.7	1.8	6.9	6.9	9.2
23	Subtotal		86.5	85.6	(0.9)	87.4	90.6	3.1	98.4	101.4	3.0	154.0	155.4	160.1

BC Hydro
F23-F25 RRA

Schedule 3.7
Page 25

Integrated Planning
Current Operating Costs and Provisions ($ million)

Line	Column	Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Distribution													
24	Energy Planning & Analytics		1.3	1.3	0.0	1.3	1.4	0.1	1.4	1.4	(0.0)	1.3	1.4	1.4
25	Asset Planning		1.6	1.6	0.0	1.6	1.7	0.1	2.0	2.0	0.0	75.1	78.4	81.9
26	Interconnections and Shared Assets		5.3	6.7	1.3	5.4	7.9	2.4	5.8	4.9	(0.9)	5.5	5.6	5.8
27	Engineering Design		2.4	2.4	(0.1)	2.5	2.2	(0.3)	2.3	2.3	(0.0)	2.2	2.3	2.3
28	Engineering Services		0.5	0.5	(0.0)	0.5	0.6	0.1	0.7	0.8	0.0	1.1	1.1	1.2
29	Business Support		0.1	0.1	(0.0)	(0.9)	(0.7)	0.2	2.8	3.8	1.1	3.8	4.0	5.8
30	Subtotal		11.2	12.5	1.3	10.5	13.1	2.6	14.9	15.1	0.2	89.1	92.8	98.3
	Business Support													
31	Energy Planning & Analytics		4.4	4.5	0.1	4.8	5.0	0.3	5.3	5.3	(0.0)	5.5	5.0	5.4
32	Asset Planning		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	1.0
33	Business Unit Support		0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.2	0.3	0.1	0.4	0.4	0.5
	Regulatory Account Recoveries - Operating Costs													
34	MRS Costs - Integrated Planning	5.0 L39	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	3.9	3.7
35	Subtotal		4.4	4.5	0.1	4.8	5.0	0.3	5.5	5.6	0.1	10.8	10.2	10.7

Capital Infrastructure Project Delivery
Current Operating Costs and Provisions ($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Current Operating Costs**	5.0 L47	120.0	119.5	(0.5)	120.0	119.1	(0.9)	118.7	118.1	(0.6)	119.0	120.2	104.2
	Internal Allocations													
2	Generation	Line 16	(53.2)	(52.5)	0.6	(54.4)	(52.9)	1.5	(49.4)	(49.0)	0.4	(48.8)	(49.0)	(44.0)
3	Transmission	Line 23	(32.0)	(31.6)	0.5	(30.8)	(30.2)	0.6	(33.4)	(33.3)	0.2	(34.1)	(34.3)	(23.1)
4	Distribution	Line 29	(5.6)	(5.5)	0.1	(5.4)	(5.7)	(0.2)	(6.1)	(6.0)	0.0	(6.1)	(6.6)	(6.6)
5	Customer Care				0.0			0.0			0.0			
6	Business Support	Line 34	(29.2)	(29.8)	(0.6)	(29.4)	(30.3)	(1.0)	(29.8)	(29.8)	0.0	(30.0)	(30.2)	(30.5)
7	Total		(120.0)	(119.5)	0.5	(120.0)	(119.1)	0.9	(118.7)	(118.1)	0.6	(119.0)	(120.2)	(104.2)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:													
	Generation													
9	Project Delivery		6.0	5.9	(0.0)	7.5	6.8	(0.7)	6.6	6.5	(0.1)	6.0	5.8	8.3
10	Indigenous Relations		1.7	1.7	(0.0)	1.8	2.1	0.3	1.9	1.9	(0.0)	2.3	2.4	2.5
11	Environment		23.6	23.3	(0.3)	23.7	22.9	(0.8)	24.3	24.0	(0.3)	24.2	24.4	24.7
12	Properties		0.7	0.7	0.0	0.7	0.7	0.0	0.7	0.7	(0.0)	0.7	0.7	0.7
13	Business Unit Support		0.3	0.3	(0.0)	0.4	0.3	(0.0)	0.5	0.5	0.0	0.3	0.3	0.4
	Regulatory Account Recoveries - Operating Costs													
14	First Nation Costs		15.6	15.3	(0.3)	15.2	14.9	(0.2)	15.5	15.5	(0.0)	15.4	15.3	7.5
15	Capital Project Investigation	5.0 L30	5.2	5.2	0.0	5.2	5.2	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
16	Subtotal		53.2	52.5	(0.6)	54.4	52.9	(1.5)	49.4	49.0	(0.4)	48.8	49.0	44.0
	Transmission													
17	Project Delivery		7.6	7.6	(0.1)	6.9	6.3	(0.6)	8.4	8.3	(0.1)	9.1	9.2	7.3
18	Indigenous Relations		2.1	2.1	(0.0)	2.1	2.5	0.4	2.3	2.3	(0.0)	2.7	2.9	3.0
19	Environment		2.9	2.9	(0.0)	3.0	2.9	(0.1)	3.4	3.4	(0.0)	3.2	3.3	3.3
20	Properties		0.1	0.1	0.0	0.1	0.1	0.0	0.2	0.1	(0.0)	0.1	0.2	0.2
21	Business Unit Support		0.1	0.1	(0.0)	0.1	0.1	(0.0)	0.3	0.3	(0.0)	0.2	0.2	0.1
	Regulatory Account Recoveries - Operating Costs													
22	First Nation Costs		19.1	18.7	(0.4)	18.5	18.2	(0.3)	18.9	18.9	(0.0)	18.8	18.6	9.1
23	Subtotal		32.0	31.6	(0.5)	30.8	30.2	(0.6)	33.4	33.3	(0.2)	34.1	34.3	23.1
	Distribution													
24	Project Delivery		0.4	0.4	(0.0)	0.1	0.1	(0.0)	0.4	0.4	(0.0)	0.1	0.5	0.3
25	Indigenous Relations		2.0	1.9	(0.0)	2.0	2.4	0.4	2.2	2.2	(0.0)	2.6	2.8	2.8
26	Environment		3.1	3.1	(0.0)	3.2	3.1	(0.1)	3.3	3.3	(0.0)	3.3	3.3	3.4
27	Properties		0.1	0.1	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Business Unit Support		0.1	0.1	(0.0)	0.1	0.1	(0.0)	0.2	0.2	(0.0)	0.1	0.1	0.1
29	Subtotal		5.6	5.5	(0.1)	5.4	5.7	0.2	6.1	6.0	(0.0)	6.1	6.6	6.6
	Business Support													
30	Indigenous Relations		0.4	0.4	(0.0)	0.4	0.4	0.1	0.4	0.4	(0.0)	0.5	0.5	0.5
31	Environment		0.1	0.1	(0.0)	0.1	0.1	(0.0)	0.0	0.0	(0.0)	0.0	0.0	0.0
32	Properties		28.4	29.1	0.6	28.6	29.5	0.9	29.4	29.4	(0.0)	29.2	29.4	29.6
33	Business Unit Support		0.3	0.3	(0.0)	0.3	0.3	(0.0)	0.0	0.0	0.0	0.3	0.3	0.3
34	Subtotal		29.2	29.8	0.6	29.4	30.3	1.0	29.8	29.8	(0.0)	30.0	30.2	30.5

BC Hydro
F23-F25 RRA

Schedule 3.9
Page 27

Operations
Current Operating Costs and Provisions ($ million)

Line	Column	Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Current Operating Costs**	5.0 L48	273.6	277.5	3.9	275.3	294.5	19.2	248.5	249.9	1.4	263.0	265.5	271.8
	Internal Allocations													
2	Generation	Line 16	(58.3)	(56.9)	1.4	(59.0)	(61.4)	(2.4)	(61.9)	(63.1)	(1.1)	(66.0)	(66.8)	(67.3)
3	Transmission	Line 23	(69.3)	(70.3)	(1.0)	(70.2)	(73.1)	(2.9)	(73.6)	(73.7)	(0.1)	(74.3)	(75.2)	(78.6)
4	Distribution	Line 31	(144.6)	(148.4)	(3.8)	(144.7)	(160.0)	(15.3)	(112.9)	(113.1)	(0.2)	(122.8)	(123.6)	(125.8)
5	Customer Care	Line 33	(1.4)	(1.9)	(0.5)	(1.4)	0.0	1.4	0.0	0.0	0.0	0.0	0.0	0.0
6	Business Support				0.0			0.0			0.0			
7	Total		(273.6)	(277.5)	(3.9)	(275.3)	(294.5)	(19.2)	(248.5)	(249.9)	(1.4)	(263.0)	(265.5)	(271.8)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:													
	Generation													
9	Program and Contract Management		0.2	0.3	0.0	0.2	0.2	0.0	0.3	0.3	0.0	2.3	2.3	1.8
10	Line Field Operations		0.2	0.2	0.0	0.2	0.2	0.0	0.2	0.2	0.0	0.2	0.2	0.2
11	Stations Field Operations		34.8	33.7	(1.1)	35.2	38.0	2.8	37.1	37.2	0.1	37.1	37.4	38.0
12	Construction Services		2.7	2.7	0.0	2.7	3.0	0.3	3.0	3.0	(0.0)	2.3	2.3	2.4
13	Generation System Operations	5.3 L6	19.7	19.2	(0.5)	20.0	19.4	(0.5)	19.8	21.1	1.3	22.5	22.9	23.3
14	T&D System Operations		0.4	0.4	0.0	0.4	0.4	0.0	0.6	0.6	0.0	0.6	0.6	0.6
15	Business Unit Support		0.3	0.5	0.1	0.3	0.2	(0.2)	0.8	0.6	(0.2)	1.0	1.0	1.0
16	Subtotal		58.3	56.9	(1.4)	59.0	61.4	2.4	61.9	63.1	1.1	66.0	66.8	67.3
	Transmission													
17	Program and Contract Management		3.5	4.0	0.5	3.5	3.5	0.0	4.2	4.4	0.2	5.4	5.5	5.4
18	Line Field Operations		5.9	6.0	0.1	6.0	7.1	1.1	6.3	6.3	0.0	6.3	6.2	6.3
19	Stations Field Operations		12.0	11.7	(0.4)	12.2	13.2	1.0	12.1	12.1	0.0	12.5	12.6	14.9
20	Construction Services		8.3	8.3	0.0	8.4	9.3	0.9	9.3	9.2	(0.1)	8.1	8.1	8.3
21	T&D System Operations		39.4	40.0	0.6	39.9	39.9	0.0	41.0	41.2	0.2	41.2	42.0	42.9
22	Business Unit Support		0.3	0.4	0.1	0.3	0.1	(0.2)	0.8	0.6	(0.2)	0.8	0.8	0.9
23	Subtotal		69.3	70.3	1.0	70.2	73.1	2.9	73.6	73.7	0.1	74.3	75.2	78.6
	Distribution													
24	Program and Contract Management		10.3	11.9	1.6	10.5	10.6	0.1	12.8	13.3	0.6	11.6	11.8	13.0
25	Line Field Operations		79.8	80.8	1.0	80.5	95.8	15.3	85.8	86.2	0.4	85.7	85.5	85.6
26	Stations Field Operations		6.1	5.9	(0.2)	6.1	6.6	0.5	6.6	6.6	0.0	6.4	6.5	6.7
27	Distribution Design & Customer Connect	5.3 L4	14.8	15.9	1.1	15.1	14.6	(0.4)	16.4	16.2	(0.3)	17.4	17.9	18.4
28	Construction Services		2.3	2.3	0.0	2.3	2.5	0.3	2.6	2.5	(0.0)	3.6	3.6	3.7
29	Business Unit Support		0.7	0.9	0.2	0.7	0.3	(0.4)	1.7	1.2	(0.5)	1.9	1.9	1.9
	Regulatory Account Recoveries - Operating Costs													
30	Storm Restoration	5.0 L29	30.6	30.6	0.0	29.5	29.5	0.0	(12.9)	(12.9)	0.0	(3.8)	(3.7)	(3.6)
31	Subtotal		144.6	148.4	3.8	144.7	160.0	15.3	112.9	113.1	0.2	122.8	123.6	125.8
	Customer Care													
32	Business Unit Support (incl. Waneta 2/3)		1.4	1.9	0.5	1.4	0.0	(1.4)	0.0	0.0	0.0	0.0	0.0	0.0
33	Subtotal		1.4	1.9	0.5	1.4	0.0	(1.4)	0.0	0.0	0.0	0.0	0.0	0.0

BC Hydro
F23-F25 RRA

Schedule 3.10
Page 28

Safety & Compliance
Current Operating Costs and Provisions ($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Current Operating Costs**	5.0 L49	57.8	56.4	(1.4)	58.5	63.7	5.2	68.3	66.2	(2.1)	66.0	66.5	68.4
	Internal Allocations													
2	Generation				0.0			0.0			0.0			
3	Transmission				0.0			0.0			0.0			
4	Distribution				0.0			0.0			0.0			
5	Customer Care				0.0			0.0			0.0			
6	Business Support	Line 15	(57.8)	(56.4)	1.4	(58.5)	(63.7)	(5.2)	(68.3)	(66.2)	2.1	(66.0)	(66.5)	(68.4)
7	Total		(57.8)	(56.4)	1.4	(58.5)	(63.7)	(5.2)	(68.3)	(66.2)	2.1	(66.0)	(66.5)	(68.4)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:													
	Business Support													
9	Safety	5.4 L1	21.7	20.8	(0.8)	21.9	19.4	(2.6)	22.5	22.3	(0.2)	20.1	20.5	20.7
10	Learning and Development	5.4 L2	23.8	21.3	(2.6)	24.2	19.2	(5.0)	24.5	24.1	(0.4)	23.9	25.3	27.0
11	Security and Emergency Management	5.4 L3	10.7	12.3	1.6	10.8	16.4	5.7	12.5	12.4	(0.1)	12.6	13.8	14.4
12	Reliability Standards Assurance	5.4 L4	1.0	1.4	0.4	1.0	8.0	7.0	8.1	6.8	(1.3)	8.3	5.9	5.2
13	Business Unit Support	5.4 L5	0.6	0.6	(0.0)	0.6	0.7	0.1	0.8	0.7	(0.1)	0.6	0.7	0.7
	Regulatory Account Recoveries - Operating Costs													
14	MRS Costs - Safety & Compliance	5.0 L40	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4
15	Subtotal		57.8	56.4	(1.4)	58.5	63.7	5.2	68.3	66.2	(2.1)	66.0	66.5	68.4

BC Hydro
F23-F25 RRA

Schedule 3.11
Page 29

Finance, Technology, Supply Chain
Current Operating Costs and Provisions ($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Current Operating Costs**	5.0 L50	262.6	265.1	2.5	264.8	277.3	12.5	299.1	300.0	0.9	309.8	316.3	320.5
	Internal Allocations													
2	Generation				0.0			0.0			0.0			
3	Transmission	Line 10	(0.8)	(0.8)	0.0	(0.8)	(0.8)	0.0	(1.0)	(1.0)	0.0	(1.0)	(1.0)	(1.0)
4	Distribution				0.0			0.0			0.0			
5	Customer Care				0.0			0.0			0.0			
6	Business Support	Line 16	(261.8)	(264.2)	(2.5)	(263.9)	(276.5)	(12.5)	(298.1)	(299.0)	(0.9)	(308.8)	(315.3)	(319.5)
7	Total		(262.6)	(265.1)	(2.5)	(264.8)	(277.3)	(12.5)	(299.1)	(300.0)	(0.9)	(309.8)	(316.3)	(320.5)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:													
	Transmission													
9	Technology - MODS costs		**0.8**	**0.8**	0.0	**0.8**	**0.8**	(0.0)	**1.0**	**1.0**	0.0	**1.0**	**1.0**	**1.0**
10	Subtotal		0.8	0.8	0.0	0.8	0.8	(0.0)	1.0	1.0	0.0	1.0	1.0	1.0
	Business Support													
11	Finance	5.5 L1	31.6	31.6	0.0	32.1	46.0	13.9	51.0	51.0	(0.0)	51.1	52.5	54.0
12	Technology (excl. MODS costs)	5.5 L2- Line 9	134.9	137.6	2.6	135.5	137.0	1.4	145.3	147.4	2.1	156.9	161.4	163.0
13	Supply Chain	5.5 L3	94.5	94.3	(0.2)	95.5	92.7	(2.7)	101.0	99.8	(1.2)	98.6	99.2	100.2
14	Business Unit Support	5.5 L4	0.8	0.8	(0.0)	0.8	0.8	(0.0)	0.9	0.9	0.0	0.8	0.9	0.9
	Regulatory Account Recoveries - Operating Costs													
15	MRS Costs - FTSC	5.0 L41	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	1.3
16	Subtotal		261.8	264.2	2.5	263.9	276.5	12.5	298.1	299.0	0.9	308.8	315.3	319.5

Customer and Corporate Affairs
Current Operating Costs and Provisions ($ million)

			F2020			F2021			F2022			F2023	F2024	F2025
		Reference	Decision	Actual	Diff	Decision	Actual	Diff	Decision	Forecast	Diff	Plan	Plan	Plan
Line	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Current Operating Costs**	5.0 L51	116.8	116.6	(0.2)	116.7	121.0	4.3	123.7	124.0	0.4	142.4	143.8	145.7
	Internal Allocations													
2	Generation				0.0			0.0			0.0			
3	Transmission	Line 22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.4)	(0.8)
4	Distribution	L11+L23	(29.4)	(29.6)	(0.2)	(28.5)	(28.6)	(0.2)	(26.6)	(26.6)	0.0	(28.5)	(28.1)	(27.9)
5	Customer Care	Line 17	(68.3)	(65.5)	2.9	(69.0)	(65.0)	4.0	(68.9)	(68.8)	0.1	(85.7)	(86.6)	(87.7)
6	Business Support	Line 21	(19.0)	(21.6)	(2.5)	(19.3)	(27.4)	(8.1)	(28.2)	(28.7)	(0.5)	(28.1)	(28.7)	(29.4)
7	Total		(116.8)	(116.6)	0.2	(116.7)	(121.0)	(4.3)	(123.7)	(124.0)	(0.4)	(142.4)	(143.8)	(145.7)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:													
	Distribution													
	Regulatory Account Recoveries - Operating Costs													
9	Smart Metering & Infrastructure	5.0 L31	29.4	29.6	0.2	28.5	28.6	0.2	26.6	26.6	0.0	25.8	25.1	24.6
10	EV Charging Infrastructure	5.0 L36	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	2.6	2.5
11	Subtotal		29.4	29.6	0.2	28.5	28.6	0.2	26.6	26.6	0.0	28.4	27.7	27.1
	Customer Care													
12	Customer Services	5.6 L1	62.4	60.5	(1.9)	63.0	61.5	(1.5)	67.8	67.7	(0.1)	67.8	69.2	70.7
13	Conservation and Energy Management	5.6 L2	0.6	0.6	(0.0)	0.6	0.5	(0.1)	0.7	0.7	(0.0)	0.6	0.7	0.7
14	Customer Crisis Fund	5.6 L9	5.3	4.4	(0.9)	5.3	2.9	(2.4)	0.5	0.5	0.0	0.0	0.0	0.0
	Regulatory Account Recoveries - Operating Costs													
15	Customer Crisis Fund	5.0 L37	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.6	14.2	13.8
16	Mining Customer Payment Plan	5.0 L38	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	2.6	2.5
17	Subtotal		68.3	65.5	(2.9)	69.0	65.0	(4.0)	68.9	68.8	(0.1)	85.7	86.6	87.7
	Business Support													
18	Communications and Community Engagement	5.6 L3	12.9	12.7	(0.2)	13.0	12.9	(0.2)	14.2	13.9	(0.3)	13.9	14.2	14.5
19	Regulatory and Rates	5.6 L4	5.4	8.1	2.8	5.4	13.7	8.3	13.1	13.9	0.8	13.4	13.7	14.0
20	Business Unit Support	5.6 L5	0.8	0.7	(0.1)	0.8	0.8	(0.0)	0.9	0.9	0.0	0.8	0.9	0.9
21	Subtotal		19.0	21.6	2.5	19.3	27.4	8.1	28.2	28.7	0.5	28.1	28.7	29.4
	Regulatory Account Recoveries - Operating Costs													
	Load Attraction													
22	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4	0.8
23	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4	0.8
24	Total	5.0 L42	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.8	1.6

BC Hydro
F23-F25 RRA

Schedule 3.13
Page 31

Other
Current Operating Costs and Provisions ($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Current Operating Costs**	5.0 L52	16.0	18.8	2.8	39.7	9.3	(30.4)	33.1	32.3	(0.9)	31.5	31.9	37.8
2	**Non-Current PEB - Pension**	5.0 L53	51.4	56.8	5.4	51.4	46.0	(5.4)	114.6	114.6	0.0	29.7	29.7	29.7
3	**PEB Current Pension Costs**	5.0 L54	(0.9)	(0.9)	0.0	(0.9)	(0.9)	0.0	(6.7)	(6.7)	0.0	(8.3)	(8.3)	(8.3)
4	**Subtotal**		50.5	55.9	8.2	50.5	45.1	(35.8)	107.9	107.9	(0.9)	21.4	21.4	21.4
5	**Total**		66.5	74.7	8.2	90.2	54.5	(35.8)	141.0	140.2	(0.9)	52.9	53.3	59.2
	Internal Allocations													
6	Generation	Line 24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(5.6)
7	Transmission				0.0			0.0			0.0			
8	Distribution				0.0			0.0			0.0			
9	Customer Care				0.0			0.0			0.0			
10	Business Support	Line 23	(66.5)	(74.7)	(8.2)	(90.2)	(54.5)	35.8	(141.0)	(140.2)	0.9	(52.9)	(53.3)	(53.6)
11	Total		(66.5)	(74.7)	(8.2)	(90.2)	(54.5)	35.8	(141.0)	(140.2)	0.9	(52.9)	(53.3)	(59.2)
12	**Total**		0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:													
	Business Support													
13	Office of the General Counsel	5.7 L2	11.7	12.0	0.3	11.8	15.5	3.7	13.0	13.0	0.0	12.9	12.9	12.8
14	President and Chief Operating Officer	5.7 L3	0.9	0.8	(0.0)	0.9	0.8	(0.1)	0.9	0.9	0.0	0.9	0.9	0.9
15	Human Resources	5.7 L1	22.1	22.0	(0.1)	22.4	21.0	(1.5)	24.4	23.8	(0.6)	23.6	24.1	24.6
16	Corporate Costs	5.7 L5	28.9	32.7	3.8	29.1	(3.3)	(32.4)	0.5	0.5	0.0	0.5	0.5	0.5
17	Capitalized Costs	5.7 L6	(285.8)	(287.0)	(1.2)	(286.2)	(286.4)	(0.1)	(290.4)	(290.6)	(0.2)	(291.1)	(291.1)	(291.3)
18	IFRS Ineligible Capitalized Costs	5.7 L8	170.1	170.1	0.0	192.5	192.5	0.0	214.9	214.9	0.0	214.9	214.9	214.9
	Regulatory Account Recoveries - Operating Costs													
19	IFRS PP&E	5.0 L34	29.9	29.9	0.0	31.0	31.0	0.0	31.6	31.6	0.0	31.6	31.6	31.6
20	IFRS Pension	5.0 L35	38.2	38.2	(0.0)	38.2	38.2	(0.0)	38.2	38.2	0.0	38.2	38.2	38.2
21	Non-Current PEB - Pension	5.0 L53	51.4	56.8	5.4	51.4	46.0	(5.4)	114.6	114.6	0.0	29.7	29.7	29.7
22	PEB Current Pension Costs	5.0 L54	(0.9)	(0.9)	0.0	(0.9)	(0.9)	0.0	(6.7)	(6.7)	0.0	(8.3)	(8.3)	(8.3)
23	Subtotal		66.5	74.7	8.2	90.2	54.5	(35.8)	141.0	140.2	(0.9)	52.9	53.3	53.6
	Generation													
	Regulatory Account Recoveries - Operating Costs													
24	Site C Project	5.0 L43	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6

Cost of Energy

			F2020			F2021			F2022			F2023	F2024	F2025
		Reference	Decision	Actual	Diff	Decision	Actual	Diff	Decision	Forecast	Diff	Plan	Plan	Plan
Line		Column	1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Gross Cost of Energy**	L62	1,867.9	1,810.9	(57.0)	1,666.5	1,522.4	(144.0)	1,670.1	1,663.7	(6.4)	1,781.6	1,943.3	2,001.4
2	**Deferral Account Additions**	L63:L69+ L72:L77	(0.2)	(18.7)	(18.5)	(0.3)	189.7	189.9	(0.4)	(21.3)	(21.0)	0.0	0.0	0.0
3	**Subtotal before Recoveries**		1,867.7	1,792.2	(75.5)	1,666.2	1,712.1	45.9	1,669.8	1,642.3	(27.4)	1,781.6	1,943.3	2,001.4
4	**Deferral Account Recoveries**	L70:L71+ L78:L79	(233.0)	(239.7)	(6.7)	(128.5)	(346.3)	(217.8)	0.0	0.0	0.0	6.8	2.2	(0.4)
5	**Current Cost of Energy**	L80	1,634.8	1,552.5	(82.3)	1,537.7	1,365.8	(171.9)	1,669.8	1,642.3	(27.4)	1,788.4	1,945.5	2,001.0
	Sources of Supply (GWh)													
	Heritage Energy													
6	Hydro Generation (Water Rentals)		39,368	40,383	1,015	44,522	49,796	5,275	46,563	48,315	1,752	46,134	45,620	45,893
7	Natural Gas for Thermal Generation		181	171	(10)	195	150	(46)	222	158	(64)	187	216	217
8	Exchange Net		(473)	(581)	(108)	(250)	(355)	(105)	(211)	(612)	(402)	(363)	(326)	(374)
9	Subtotal		39,075	39,972	897	44,467	49,591	5,124	46,574	47,860	1,286	45,957	45,510	45,737
10	Electrification Plan - Heritage Energy		0	0	0	0	0	0	0	0	0	(360)	227	(120)
11	Total		39,075	39,972	897	44,467	49,591	5,124	46,574	47,861	1,286	45,598	45,738	45,617
	Non-Heritage Energy													
12	IPPs and Long-Term Commitments		13,949	14,475	526	15,238	14,630	(608)	15,980	15,430	(550)	15,959	16,003	16,008
13	Non-Integrated Area		118	106	(11)	120	107	(13)	109	108	(1)	110	111	110
14	Total		14,067	14,581	514	15,358	14,737	(621)	16,089	15,539	(551)	16,069	16,114	16,118
	Market Energy													
15	Market Electricity Purchases		3,633	3,471	(162)	1,326	0	(1,326)	0	0	(0)	0	0	0
16	Surplus Sales		(84)	(182)	(98)	(3,515)	0	3,515	0	0	0	0	0	0
17	System Imports						999	999	1,956	1,451	(505)	2,617	3,308	3,667
18	System Exports						(9,082)	(9,082)	(6,796)	(7,172)	(376)	(5,813)	(5,048)	(4,560)
19	Net Purchases (Sales) from Powerex		468	(940)	(1,407)	(279)	0	279	0	0	0	0	0	0
20	Subtotal		4,017	2,349	(1,667)	(2,467)	(8,083)	(5,616)	(4,840)	(5,721)	(881)	(3,196)	(1,740)	(892)
21	Electrification Plan - Market Energy		0	0	0	0	0	0	0	(0)	(0)	702	1,205	2,536
22	Total		4,017	2,349	(1,667)	(2,467)	(8,083)	(5,616)	(4,840)	(5,721)	(881)	(2,494)	(535)	1,644
23	**Total Sources of Supply**	L11+L14+L22	57,159	56,903	(256)	57,357	56,245	(1,112)	57,823	57,678	(146)	59,172	61,317	63,380
24	**Less Line Loss and System Use**		(5,200)	(4,972)	228	(5,416)	(5,105)	311	(5,376)	(5,472)	(96)	(5,482)	(5,583)	(5,723)
25	**Total Domestic Sales**	14.0 L16	51,958	51,931	(27)	51,940	51,139	(801)	52,448	52,206	(242)	53,691	55,733	57,657
26	**Line Loss as % of Sales**		10.01%	9.57%	(0.43%)	10.43%	9.98%	(0.45%)	10.25%	10.48%	0.23%	10.21%	10.02%	9.93%
	Unit Costs ($/MWh)													
27	Hydro Generation (Water Rentals)		8.4	8.2	(0.2)	7.3	6.7	(0.5)	8.1	8.0	(0.1)	8.4	8.4	8.4
28	Natural Gas for Thermal Generation		41.8	41.7	(0.1)	43.7	43.3	(0.3)	53.1	51.6	(1.5)	51.8	49.4	49.3
29	IPPs and Long-Term Commitments		92.8	90.8	(2.0)	92.6	96.0	3.4	92.3	92.5	0.1	92.2	93.1	94.0
30	Non-Integrated Area		259.1	293.8	34.7	250.7	242.9	(7.8)	251.2	243.9	(7.3)	258.6	270.9	274.9
31	Market Electricity Purchases		41.5	38.4	(3.1)	32.9	0.0	(32.9)	0.0	0.0	0.0	0.0	0.0	0.0
32	Surplus Sales		(5.0)	(5.5)	(0.5)	(47.0)	0.0	47.0	0.0	0.0	0.0	0.0	0.0	0.0
33	System Imports						26.9	26.9	39.4	47.6	8.2	48.0	45.1	43.1
34	System Exports						25.1	25.1	43.6	37.2	(6.5)	38.4	37.0	35.3
35	Electrification Plan - Heritage Energy									0.0	0.0	1.2	(5.9)	(0.4)

Cost of Energy

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
36	Electrification Plan - Market Energy						0.0			0.0	0.0	1.5	64.0	35.4
37	Total Weighted Cost		35.9	34.9	(1.1)	32.1	29.8	(2.3)	31.8	31.9	0.0	33.2	34.9	34.7
	Cost of Energy ($ million)													
	Heritage Energy													
38	Water Rentals		329.3	331.6	2.3	323.2	333.2	10.0	375.4	385.0	9.5	389.0	384.9	385.7
39	Natural Gas for Thermal Generation		7.5	7.1	(0.4)	8.5	6.5	(2.0)	11.8	8.2	(3.6)	9.7	10.7	10.7
40	Domestic Transmission - Other		24.5	24.8	0.3	24.4	25.5	1.1	25.5	24.6	(1.0)	25.1	25.7	26.2
41	Non-Treaty Storage and Libby Coordination Agreements		15.0	37.7	22.7	(11.7)	(49.9)	(38.1)	(19.0)	10.0	29.0	(26.3)	(9.4)	(19.5)
42	Remissions and Other		(25.2)	(42.4)	(17.2)	(26.7)	(42.0)	(15.4)	(43.2)	(41.5)	1.7	(44.0)	(44.7)	(44.0)
43	Subtotal		351.2	358.8	7.7	317.7	273.3	(44.4)	350.6	386.2	35.6	353.5	367.2	359.1
44	Electrification Plan - Heritage Energy				0.0			0.0		0.0	0.0	(0.4)	(1.3)	0.0
45	Electrification Plan - NTSA				0.0			0.0		0.0	0.0	2.9	(5.1)	(2.1)
46	Total		351.2	358.8	7.7	317.7	273.3	(44.4)	350.6	386.2	35.6	356.0	360.7	357.0
	Non-Heritage Energy													
47	IPPs and Long-Term Commitments		1,294.7	1,314.0	19.3	1,410.8	1,404.0	(6.8)	1,475.7	1,426.9	(48.7)	1,471.9	1,490.5	1,504.3
48	Non-Integrated Area		30.5	31.3	0.7	30.2	26.0	(4.1)	27.4	26.5	(1.0)	28.4	30.0	30.4
49	Gas & Other Transportation		3.7	4.5	0.8	2.5	5.3	2.7	4.9	4.3	(0.6)	4.4	4.5	4.5
50	Water Rentals (Waneta 2/3)	15.0 L28	3.5	3.3	(0.2)	3.7	3.2	(0.5)	3.5	3.4	(0.0)	3.5	3.7	3.8
51	Total		1,332.4	1,353.1	20.7	1,447.2	1,438.5	(8.6)	1,511.5	1,461.1	(50.3)	1,508.2	1,528.7	1,543.0
	Market Energy													
52	Market Electricity Purchases		150.6	133.1	(17.4)	43.7	0.0	(43.7)	0.0	0.0	0.0	0.0	0.0	0.0
53	Surplus Sales		(0.4)	(1.0)	(0.6)	(165.1)	0.0	165.1	0.0	0.0	0.0	0.0	0.0	0.0
54	System Imports						26.9	26.9	77.1	69.0	(8.0)	125.6	149.2	157.9
55	System Exports						(227.9)	(227.9)	(296.5)	(266.5)	30.0	(223.3)	(186.7)	(160.9)
56	Net Purchases (Sales) from Powerex		33.1	(35.2)	(68.3)	6.1	0.0	(6.1)	0.0	0.0	0.0	0.0	0.0	0.0
57	Domestic Transmission - Export		1.1	2.0	0.9	17.0	11.6	(5.4)	27.5	13.8	(13.7)	14.1	14.3	14.6
58	Subtotal		184.4	99.0	(85.4)	(98.4)	(189.4)	(91.0)	(191.9)	(183.7)	8.3	(83.7)	(23.2)	11.6
59	Electrification Plan - Market Energy				0.0			0.0		0.0	0.0	1.1	77.1	89.8
60	Total		184.4	99.0	(85.4)	(98.4)	(189.4)	(91.0)	(191.9)	(183.7)	8.3	(82.6)	53.9	101.4
61	**Total Gross COE**	L46+L51+L60	1,867.9	1,810.9	(57.0)	1,666.5	1,522.4	(144.0)	1,670.1	1,663.7	(6.4)	1,781.6	1,943.3	2,001.4
	Current Cost of Energy													
62	Gross Cost of Energy	Line 61	1,867.9	1,810.9	(57.0)	1,666.5	1,522.4	(144.0)	1,670.1	1,663.7	(6.4)	1,781.6	1,943.3	2,001.4
63	HDA Additions	2.1 L3	0.0	82.4	82.4	0.0	(138.4)	(138.4)	0.0	(22.9)	(22.9)	0.0	0.0	0.0
64	NHDA Additions	2.1 L11+L13	0.0	(100.1)	(100.1)	0.0	464.3	464.3	0.0	15.5	15.5	0.0	0.0	0.0
65	Deferred Operating HDA	Line 94	0.0	(1.4)	(1.4)	0.0	(1.5)	(1.5)	0.0	0.7	0.7	0.0	0.0	0.0
66	Deferred Operating NHDA	Line 109	0.0	0.0	0.0	0.0	1.5	1.5	0.0	0.6	0.6	0.0	0.0	0.0
67	Deferred Amortization NHDA	Line 110	0.0	0.4	0.4	0.0	(0.3)	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0
68	Deferred Taxes NHDA	Line 111	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
69	Deferred Provision NHDA	Line 112	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
70	HDA Recoveries	2.1 L6	(272.6)	(280.6)	(7.9)	(229.5)	(229.5)	0.0	0.0	0.0	0.0	43.7	22.2	11.0
71	NHDA Recoveries	2.1 L15	(43.0)	40.9	83.9	(116.8)	(116.8)	0.0	0.0	0.0	0.0	(92.0)	(47.9)	(25.3)
72	Load Variance Additions - Revenue	2.1 L27	0.0	0.0	0.0	0.0	(106.1)	(106.1)	0.0	(20.9)	(20.9)	0.0	0.0	0.0
73	Biomass Energy Program Variance Additions - Cost of E	2.1 L34	0.0	0.0	0.0	0.0	19.0	19.0	0.0	5.7	5.7	0.0	0.0	0.0
74	Biomass Energy Program Variance Additions - Revenue	2.1 L35	0.0	0.0	0.0	0.0	(4.9)	(4.9)	0.0	0.0	0.0	0.0	0.0	0.0
75	Customer Crisis Fund Additions - COVID-19 Res. Grant	2.2 L136	0.0	0.0	0.0	0.0	(37.3)	(37.3)	0.0	0.0	0.0	0.0	0.0	0.0
76	Mining Cust. Pay. Plan Additions - COVID-19 SGS Wai	2.2 L143	0.0	0.0	0.0	0.0	(6.3)	(6.3)	0.0	0.0	0.0	0.0	0.0	0.0

Cost of Energy

Line	Column	Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
77	Electric Vehicle Costs Additions - Cost of Energy		(0.2)	0.0	0.2	(0.3)	(0.3)	(0.1)	(0.4)	(0.1)	0.2	0.0	0.0	0.0
78	Load Variance Recoveries	2.1 L30	82.7	0.0	(82.7)	217.8	0.0	(217.8)	0.0	0.0	0.0	65.1	33.0	16.4
79	Biomass Energy Program Variance Recoveries	2.1 L39	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(10.0)	(5.1)	(2.5)
80	**Total Current COE**		1,634.8	1,552.5	(82.3)	1,537.7	1,365.8	(171.9)	1,669.8	1,642.3	(27.4)	1,788.4	1,945.5	2,001.0
	Total Current COE by Function													
81	Generation		229.8	293.4	63.7	(16.3)	(84.5)	(68.2)	378.1	377.8	(0.3)	413.8	397.3	382.6
82	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
83	Customer Care		1,405.0	1,259.0	(145.9)	1,554.0	1,450.3	(103.7)	1,291.7	1,264.5	(27.1)	1,374.6	1,548.3	1,618.3
84	Total		1,634.8	1,552.5	(82.3)	1,537.7	1,365.8	(171.9)	1,669.8	1,642.3	(27.4)	1,788.4	1,945.5	2,001.0
	Items Subject to HDA													
85	Heritage Energy	Line 46	351.2	358.8	7.7	317.7	273.3	(44.4)	350.6	386.2	35.6	356.0	360.7	357.0
86	Less: F15-F19 Water Rentals (Waneta 1/3)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
87	Market Electricity Purchases	Line 52	150.6	133.1	(17.4)	43.7	0.0	(43.7)	0.0	0.0	0.0	0.0	0.0	0.0
88	Surplus Sales	Line 53	(0.4)	(1.0)	(0.6)	(165.1)	0.0	165.1	0.0	0.0	0.0	0.0	0.0	0.0
89	Electric Vehicle Costs Additions	Line 77	(0.2)	0.0	0.2	(0.3)	(0.3)	(0.1)	0.0	(0.1)	(0.1)	0.0	0.0	0.0
90	Domestic Transmission - Export	Line 57	1.1	2.0	0.9	17.0	11.6	(5.4)	27.5	13.8	(13.7)	14.1	14.3	14.6
91	Costs in Operating/Amortization		12.5	12.5	0.0	12.5	12.5	0.0	12.5	13.2	0.7	12.6	12.8	12.9
92	Notional Water Rentals		3.1	(6.1)	(9.2)	(1.8)	0.0	1.8	0.0	0.0	0.0	0.0	0.0	0.0
93	Skagit and Ancillary Revenue	14.0 L24 / L51	(36.1)	(29.7)	6.4	(35.9)	(30.0)	5.9	(30.2)	(30.0)	0.2	(30.0)	(30.0)	(30.0)
94	Deferred Operating HDA	5.0 L56	0.0	(1.4)	(1.4)	0.0	(1.5)	(1.5)	0.0	0.7	0.7	0.0	0.0	0.0
95	Other		31.5	31.0	(0.5)	31.2	31.2	0.0	32.3	32.3	0.0	32.3	32.3	32.3
96	Total		513.3	499.3	(14.0)	219.0	296.9	77.8	392.7	416.2	23.5	385.0	390.3	386.9
97	**Total System Inflow (% of Average)**		87%	93%	6%	100%	111%	11%	100%	102%	2%	100%	100%	100%
	Items Subject to NHDA													
98	Non-Heritage Cost of Energy	Line 51	1,332.4	1,353.1	20.7	1,447.2	1,438.5	(8.6)	1,511.5	1,461.1	(50.3)	1,508.2	1,528.7	1,543.0
99	Add: F15-F19 Water Rentals (Waneta 1/3)	Line 86	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
100	Less: Water Rentals (Waneta 2/3)	Line 50	(3.5)	(3.3)	0.2	(3.7)	(3.2)	0.5	(3.5)	(3.4)	0.0	(3.5)	(3.7)	(3.8)
101	Net Purchases (Sales) from Powerex	Line 56	33.1	(35.2)	(68.3)	6.1	0.0	(6.1)	0.0	0.0	0.0	0.0	0.0	0.0
102	System Imports	Line 54					26.9	26.9	77.1	69.0	(8.0)	125.6	149.2	157.9
103	System Exports	Line 55					(227.9)	(227.9)	(296.5)	(266.5)	30.0	(223.3)	(186.7)	(160.9)
104	Electrification Plan	Line 59						0.0	0.0	0.0	0.0	1.1	77.1	89.8
105	Commodity Risk		(1.4)	0.8	2.2	0.0	90.0	90.0	0.0	0.0	0.0	0.0	0.0	0.0
106	Notional Water Rental	Line 92	(3.1)	6.1	9.2	1.8	0.0	(1.8)	0.0	0.0	0.0	0.0	0.0	0.0
107	Electric Vehicle Costs Additions				0.0		0.0	0.0	(0.4)		0.4			
108	Revenue Variance		0.0	139.3	139.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
109	Deferred Operating NHDA	5.0 L57	0.0	0.0	0.0	0.0	1.5	1.5	0.0	0.6	0.6	0.0	0.0	0.0
110	Deferred Amortization NHDA	7.0 L24	0.0	0.4	0.4	0.0	(0.3)	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0
111	Deferred Taxes NHDA	6.0 L22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
112	Deferred Provision NHDA	5.01 L37	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
113	Other		0.0	(3.6)	(3.6)	0.0	(1.6)	(1.6)	0.0	9.2	9.2	0.0	0.0	0.0
114	Less: IPP subject to Biomass Energy Program Variance		(35.8)	(31.6)	4.3	(80.7)	(66.0)	14.7	(102.4)	(99.6)	2.8	(113.3)	(115.7)	(118.1)
115	Total		1,321.7	1,426.1	104.4	1,370.7	1,258.0	(112.7)	1,185.8	1,170.5	(15.3)	1,294.6	1,448.8	1,507.9
116	**Biomass Energy Program Cost Def. Acct.**		35.8	31.6	(4.3)	80.7	66.0	(14.7)	102.4	99.6	(2.8)	113.3	115.7	118.1

IPP Summary

BC Hydro **Schedule 4.0**
F23-F25 RRA **Page 35**

Cost of Energy

			F2020			F2021			F2022			F2023	F2024	F2025
		Reference	**Decision**	**Actual**	**Diff**	**Decision**	**Actual**	**Diff**	**Decision**	**Forecast**	**Diff**	**Plan**	**Plan**	**Plan**
Line	**Column**		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
117	IPP Costs in Non-Heritage COE	Line 47	1,294.7	1,314.0	19.3	1,410.8	1,404.0	(6.8)	1,475.7	1,426.9	(48.7)	1,471.9	1,490.5	1,504.3
	Existing Capital Leases													
118	Amortization	7.0 L21	88.9	88.9	0.0	90.1	90.1	0.0	90.6	90.6	(0.0)	61.4	59.5	60.3
119	Finance Charges	8.0 L26	48.4	48.4	0.0	46.1	46.1	0.0	43.5	43.5	(0.0)	41.4	40.1	38.7
120	Total		137.4	137.4	0.0	136.1	136.1	0.0	134.1	134.0	(0.1)	102.9	99.6	99.0
121	Transfers to Deferral & Regulatory Accounts		0.0	0.4	0.4	0.0	(0.3)	(0.3)	0.0	(0.0)	(0.0)	0.0	0.0	0.0
122	Total Costs in Revenue Requirement		1,432.1	1,451.8	19.7	1,546.9	1,539.9	(7.0)	1,609.7	1,560.9	(48.8)	1,574.7	1,590.0	1,603.3
123	Total Payments to IPPs		1,416.6	1,430.9	14.3	1,533.1	1,508.0	(25.0)	1,601.3	1,552.5	(48.8)	1,566.2	1,585.1	1,600.0
124	Difference	L122 - L123	15.5	20.9	5.4	13.9	31.9	18.0	8.5	8.4	(0.0)	8.5	5.0	3.3
	IPP Capital Leases													
	Gross Assets in Service													
125	Opening Balance		694.7	694.7	0.0	1,751.5	1,978.6	227.1	1,984.4	1,984.4	0.0	1,997.0	2,011.0	2,025.4
126	Capital Additions		1,751.5	1,978.6	227.1	0.0	5.7	5.7	0.0	12.6	12.6	14.0	14.5	13.5
127	Retirements & Transfers		(694.7)	(694.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
128	Closing Balance		1,751.5	1,978.6	227.1	1,751.5	1,984.4	232.9	1,984.4	1,997.0	12.6	2,011.0	2,025.4	2,038.9
	Accumulated Amortization													
129	Opening Balance		77.0	77.0	0.0	592.9	613.0	20.1	702.9	702.9	0.0	793.5	854.9	914.4
130	Adjustment to Opening Balance		427.0	523.7	96.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
131	Amortization		88.9	89.3	0.4	90.1	89.8	(0.3)	90.6	90.6	(0.0)	61.4	59.5	60.3
132	Retirements & Transfers		0.0	(77.0)	(77.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
133	Closing Balance		592.9	613.0	20.1	683.0	702.9	20.0	793.5	793.5	(0.0)	854.9	914.4	974.7
134	**Net Capital Leases (Year-End)**		1,158.6	1,365.6	207.0	1,068.5	1,281.4	212.9	1,190.8	1,203.5	12.7	1,156.1	1,111.0	1,064.2

Operating Costs - Total Company
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Gross Operating Costs**	L74	1,136.1	1,115.2	(20.9)	1,135.4	1,128.7	(6.6)	1,228.5	1,218.6	(9.9)	1,286.8	1,314.4	1,348.4
2	**Deferral Account Additions**	L58	0.0	1.4	1.4	0.0	0.0	0.0	0.0	(1.4)	(1.4)	0.0	0.0	0.0
3	**Regulatory Account Additions**	L73	(159.0)	(132.6)	26.4	(125.4)	(91.8)	33.6	(102.0)	(90.7)	11.3	(139.4)	(146.4)	(148.6)
4	**Net Operating Costs**		977.1	984.0	6.9	1,010.0	1,036.9	26.9	1,126.5	1,126.5	0.0	1,147.4	1,167.9	1,199.9
5	**Regulatory Account Recoveries**	L44	218.7	223.6	4.9	216.7	210.9	(5.8)	225.8	225.8	(0.0)	173.2	172.3	160.3
6	**Current Operating Costs**	L45	1,195.8	1,207.6	11.8	1,226.7	1,247.9	21.2	1,352.3	1,352.3	(0.0)	1,320.5	1,340.3	1,360.2
	Operating Costs by Business Group													
7	Integrated Planning	5.1 L8	292.7	292.5	(0.3)	295.2	311.9	16.6	346.9	347.8	0.9	357.6	364.6	380.4
8	Capital Infrastructure Project Delivery	5.2 L6	80.1	80.1	0.1	81.1	80.8	(0.3)	84.3	83.7	(0.6)	84.8	86.3	87.6
9	Operations	5.3 L9	243.0	246.9	3.9	245.8	265.0	19.2	261.4	262.8	1.4	266.8	269.2	275.3
10	Safety & Compliance	5.4 L6	57.8	56.4	(1.4)	58.5	63.7	5.2	68.3	66.2	(2.1)	65.6	66.1	68.0
11	Finance, Technology, Supply Chain	5.5 L5	262.6	265.1	2.5	264.8	277.3	12.5	299.1	300.0	0.9	308.4	314.9	319.1
12	Customer and Corporate Affairs	5.6 L6	82.1	82.6	0.6	82.9	89.4	6.5	96.6	97.0	0.4	96.6	98.6	100.8
13	Other	5.7 L7	(222.2)	(219.4)	2.8	(222.0)	(252.4)	(30.4)	(251.6)	(252.4)	(0.9)	(253.2)	(252.8)	(252.5)
14	**Base Operating Costs**		796.1	804.2	8.1	806.3	835.7	29.4	905.117	905.1	0.0	926.6	947.0	978.7
15	IFRS Ineligible Capitalized Costs		170.1	170.1	0.0	192.5	192.5	0.0	214.9	214.9	0.0	214.9	214.9	214.9
16	Waneta 2/3		5.7	5.4	(0.3)	5.9	5.8	(0.0)	6.1	6.1	0.0	5.9	6.1	6.3
17	Customer Crisis Fund		5.3	4.4	(0.9)	5.3	2.9	(2.4)	0.5	0.5	0.0	0.0	0.0	0.0
18	**Subtotal**		181.1	179.8	(1.2)	203.6	201.2	(2.4)	221.4	221.4	0.0	220.8	221.0	221.2
19	**Net Operating Costs**	L14+L18	977.1	984.0	6.9	1,010.0	1,036.9	26.9	1,126.5	1,126.5	0.0	1,147.4	1,167.9	1,199.9
	Operating Costs by Resource													
20	Labour (excl Non-Current PEB)		592.2	601.1	8.9	602.4	628.2	25.8	651.7	653.3	1.5	656.8	677.1	699.5
21	Services - ABSU		0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
22	Services - Other		425.0	412.4	(12.7)	423.6	412.3	(11.3)	475.9	472.4	(3.6)	464.7	464.2	473.9
23	Materials		46.3	54.3	8.0	46.3	47.0	0.7	49.5	46.4	(3.1)	49.8	49.7	49.6
24	Buildings & Equipment		51.4	62.7	11.3	51.5	64.9	13.3	51.5	54.6	3.1	74.9	75.3	75.6
25	Capitalized Overhead		(115.8)	(116.9)	(1.1)	(93.8)	(93.9)	(0.2)	(75.5)	(75.7)	(0.2)	(76.2)	(76.2)	(76.4)
26	External Recoveries		(22.1)	(29.6)	(7.5)	(20.1)	(21.5)	(1.4)	(26.6)	(24.4)	2.2	(22.6)	(22.2)	(22.3)
27	Net Operating Costs		977.1	984.0	6.9	1,010.0	1,037.0	27.0	1,126.5	1,126.5	0.0	1,147.4	1,167.9	1,199.9
	Regulatory Account Recoveries - Operating Costs													
28	First Nation Costs		**34.7**	**34.1**	(0.6)	**33.7**	**33.1**	(0.5)	**34.4**	**34.4**	(0.0)	**34.1**	**33.9**	**16.6**
29	Storm Restoration		**30.6**	**30.6**	0.0	**29.5**	**29.5**	0.0	**(12.9)**	**(12.9)**	0.0	**(3.8)**	**(3.7)**	**(3.6)**
30	Capital Project Investigation		**5.2**	**5.2**	0.0	**5.2**	**5.2**	(0.0)	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
31	Smart Metering & Infrastructure		**29.4**	**29.6**	0.2	**28.5**	**28.6**	0.2	**26.6**	**26.6**	0.0	**25.8**	**25.1**	**24.6**
32	Non-Current Pension Cost		**51.4**	**56.8**	5.4	**51.4**	**46.0**	(5.4)	**114.6**	**114.6**	0.0	**29.7**	**29.7**	**29.7**
33	PEB Current Pension Costs		**(0.9)**	**(0.9)**	0.0	**(0.9)**	**(0.9)**	0.0	**(6.7)**	**(6.7)**	0.0	**(8.3)**	**(8.3)**	**(8.3)**
34	IFRS PP&E		**29.9**	**29.9**	0.0	**31.0**	**31.0**	0.0	**31.6**	**31.6**	0.0	**31.6**	**31.6**	**31.6**
35	IFRS Pension		**38.2**	**38.2**	(0.0)	**38.2**	**38.2**	(0.0)	**38.2**	**38.2**	0.0	**38.2**	**38.2**	**38.2**
36	Electric Vehicle Costs		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**2.6**	**2.6**	**2.5**
37	Customer Crisis Fund		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**14.6**	**14.2**	**13.8**
38	Mining Customer Payment Plan		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**2.6**	**2.6**	**2.5**
39	Mandatory Reliability Standard Costs - Integrated Planning		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**4.0**	**3.9**	**3.7**
40	Mandatory Reliability Standard Costs - Safety & Compliance		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.4**	**0.4**	**0.4**
41	Mandatory Reliability Standard Costs - Finance, Technology, Supply Chain		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**1.4**	**1.4**	**1.3**
42	Load Attraction Costs		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.1**	**0.8**	**1.6**

BC Hydro
F23-F25 RRA

Operating Costs - Total Company
($ million)

Line	Column	Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
43	Site C Project		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6
44	Total		218.7	223.6	4.9	216.7	210.9	(5.8)	225.8	225.8	(0.0)	173.2	172.3	160.3
45	**Total Current Operating Costs**	L19+L44	1,195.8	1,207.6	11.8	1,226.7	1,247.9	21.2	1,352.3	1,352.3	(0.0)	1,320.5	1,340.3	1,360.2
	Current Operating Costs by Business Group													
46	Integrated Planning	L7+L16+L39	298.4	297.8	(0.6)	301.1	317.7	16.6	353.0	353.9	0.9	367.5	374.6	390.4
47	Capital Infrastructure Project Delivery	L8+L28+L30	120.0	119.5	(0.5)	120.0	119.1	(0.9)	118.7	118.1	(0.6)	119.0	120.2	104.2
48	Operations	L9+L29	273.6	277.5	3.9	275.3	294.5	19.2	248.5	249.9	1.4	263.0	265.5	271.8
49	Safety & Compliance	L10+L40	57.8	56.4	(1.4)	58.5	63.7	5.2	68.3	66.2	(2.1)	66.0	66.5	68.4
50	Finance, Technology, Supply Chain	L11+L41	262.6	265.1	2.5	264.8	277.3	12.5	299.1	300.0	0.9	309.8	316.3	320.5
51	Customer and Corporate Affairs	L12+L17+L31+L36:L38+L42	116.8	116.6	(0.2)	116.7	121.0	4.3	123.7	124.0	0.4	142.4	143.8	145.7
52	Other	L13+L15+L34+L35+L43	16.0	18.8	2.8	39.7	9.3	(30.4)	33.1	32.3	(0.9)	31.5	31.9	37.8
53	Non-Current PEB - Pension	Line 32	51.4	56.8	5.4	51.4	46.0	(5.4)	114.6	114.6	0.0	29.7	29.7	29.7
54	PEB Current Pension Costs	Line 33	(0.9)	(0.9)	0.0	(0.9)	(0.9)	0.0	(6.7)	(6.7)	0.0	(8.3)	(8.3)	(8.3)
55	Total		1,195.8	1,207.6	11.8	1,226.7	1,247.9	21.2	1,352.3	1,352.3	(0.0)	1,320.5	1,340.3	1,360.2
	Deferral Account Additions													
56	Transfers to HDA		0.0	(1.4)	(1.4)	0.0	(1.5)	(1.5)	0.0	0.7	0.7	0.0	0.0	0.0
57	Transfers to NHDA		0.0	0.0	0.0	0.0	1.5	1.5	0.0	0.6	0.6	0.0	0.0	0.0
58	Total		0.0	(1.4)	(1.4)	0.0	(0.0)	(0.0)	0.0	1.4	1.4	0.0	0.0	0.0
	Regulatory Account Additions													
59	Demand-Side Management		90.8	78.5	(12.4)	89.1	77.0	(12.0)	82.2	82.2	(0.0)	83.4	85.1	87.1
60	Low Carbon Electrification		18.3	16.9	(1.4)	9.7	4.1	(5.6)	15.5	12.8	(2.7)	45.1	49.5	50.6
61	First Nations Costs		3.2	2.5	(0.6)	2.4	1.9	(0.5)	2.1	2.1	(0.0)	1.8	1.8	1.8
62	Site C Project		0.3	0.3	0.0	0.3	0.3	0.0	0.3	0.3	0.0	0.3	0.3	0.3
63	Storm Restoration		0.0	(7.8)	(7.8)	0.0	(14.2)	(14.2)	0.0	0.0	0.0	0.0	0.0	0.0
64	Smart Metering & Infrastructure		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
65	IFRS Capitalized Overhead		44.8	44.8	0.0	22.4	22.4	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
66	PEB Current Pension Costs		0.0	(0.9)	(0.9)	0.0	(5.8)	(5.8)	0.0	(24.8)	(24.8)	0.0	0.0	0.0
67	Real Property Sales		0.0	0.9	0.9	0.0	1.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0
68	Customer Crisis Fund		(0.3)	(2.7)	(2.4)	(0.3)	0.9	1.2	0.0	0.0	(0.0)	0.0	0.0	0.0
69	Electric Vehicle Costs		1.9	0.0	(1.9)	1.7	3.3	1.6	1.8	2.1	0.4	0.0	0.0	0.0
70	Mining Customer Payment Plan		0.0	0.0	0.0	0.0	0.7	0.7	0.0	0.0	0.0	0.0	0.0	0.0
71	Mandatory Reliability Standard Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.9	15.9	0.0	0.0	0.0
72	Load Attraction Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.7	9.7	8.8
73	Total		159.0	132.6	(26.4)	125.4	91.8	(33.6)	102.0	90.7	(11.3)	139.4	146.4	148.6
74	**Total Gross Operating Costs**	L19+L58+L73	1,136.1	1,115.2	(20.9)	1,135.4	1,128.7	(6.6)	1,228.5	1,218.6	(9.9)	1,286.8	1,314.4	1,348.4
75	**Before Electrification Plan**								1,228.5	1,218.6	(9.9)	1,285.6	1,312.2	1,345.6
76	**Electrification Plan**									0.0	0.0	1.1	2.1	2.8
77	**Total Gross Operating Costs**								1,228.5	1,218.6	(9.9)	1,286.8	1,314.4	1,348.4
	Operating Costs Continuity													
78	**Base Operating Costs**	Line 14	796.1	804.2	8.1	806.3	835.7	29.4	905.1	905.1	0.0	926.6	947.0	978.7
79	Base Operating Costs Adjustments	Line 18	181.1	179.8	(1.2)	203.6	201.2	(2.4)	221.4	221.4	0.0	220.8	221.0	221.2
80	**Net Operating Costs**	Line 19	**977.1**	**984.0**	**6.9**	**1,010.0**	**1,036.9**	**26.9**	**1,126.5**	**1,126.5**	**0.0**	**1,147.4**	**1,167.9**	**1,199.9**

Operating Costs - Total Company
($ million)

Line	Column	Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
81	Deferral Account Additions and Regulatory Account Additions	L58 + L73	159.0	131.2	(27.8)	125.4	91.8	(33.6)	102.0	92.1	(9.9)	139.4	146.4	148.6
82	**Gross Operating Costs**	Line 74	**1,136.1**	**1,115.2**	**(20.9)**	**1,135.4**	**1,128.7**	**(6.6)**	**1,228.5**	**1,218.6**	**(9.9)**	**1,286.8**	**1,314.4**	**1,348.4**
83	Reverse Deferral Account Additions and Regulatory Account Additions	Line 81	(159.0)	(131.2)	27.8	(125.4)	(91.8)	33.6	(102.0)	(92.1)	9.9	(139.4)	(146.4)	(148.6)
84	Regulatory Account Recoveries	Line 44	218.7	223.6	4.9	216.7	210.9	(5.8)	225.8	225.8	(0.0)	173.2	172.3	160.3
85	**Current Operating Costs**	Line 45	**1,195.8**	**1,207.6**	**11.8**	**1,226.7**	**1,247.9**	**21.2**	**1,352.3**	**1,352.3**	**(0.0)**	**1,320.5**	**1,340.3**	**1,360.2**

BC Hydro
F23-F25 RRA

Schedule 5.01
Page 39

Provisions & Other - Total Company
($ million)

Line	Column	Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Gross Provisions & Other**	L45	116.4	176.8	60.4	95.4	163.7	68.3	101.4	97.4	(4.0)	104.9	96.7	95.3
2	**Deferral Account Additions**	L37	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Regulatory Account Additions**	L44	0.0	(48.0)	(48.0)	0.0	(53.0)	(53.0)	0.0	0.4	0.4	0.0	0.0	0.0
4	**Subtotal before Recoveries**		116.4	128.7	12.4	95.4	110.7	15.3	101.4	97.8	(3.6)	104.9	96.7	95.3
5	**Regulatory Account Recoveries**	L28	46.3	46.3	(0.0)	43.3	43.3	0.0	63.9	63.9	0.0	32.9	38.9	13.3
6	**Current Provisions & Other**	L29	162.6	175.0	12.4	138.7	154.0	15.3	165.3	161.7	(3.6)	137.8	135.6	108.6
	Provisions & Other - By Business Groups													
7	Integrated Planning		67.2	108.2	41.0	71.5	72.5	1.0	75.9	74.4	(1.5)	78.1	75.6	71.3
8	Capital Infrastructure Project Delivery		1.5	(8.9)	(10.3)	0.3	14.7	14.5	0.1	1.3	1.3	0.6	0.2	0.7
9	Operations		36.6	7.0	(29.5)	12.3	11.5	(0.7)	13.4	16.0	2.6	14.4	9.2	12.7
10	Safety & Compliance		0.0	6.3	6.3	0.0	14.0	14.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Finance, Technology, Supply Chain		0.2	12.6	12.4	0.2	(8.1)	(8.3)	0.2	(4.2)	(4.3)	0.5	0.2	0.2
12	Customer and Corporate Affairs		0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Other		11.0	3.5	(7.5)	11.2	6.0	(5.2)	11.9	10.2	(1.7)	11.3	11.6	10.4
14	Total		116.4	128.7	12.4	95.4	110.7	15.3	101.4	97.8	(3.6)	104.9	96.7	95.3
	Provisions & Other - By Category													
15	Gain/loss on Capital and Intangible Assets		43.9	47.0	3.2	46.8	42.2	(4.6)	50.0	46.0	(4.0)	45.1	43.9	43.9
	Gain/Loss on Project Write-offs		0.0	15.3	15.3	0.0	(6.9)	(6.9)	0.0	0.0	0.0	0.0	0.0	0.0
16	Real Property Sales		0.0	(10.0)	(10.0)	0.0	10.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Bank Fees and Other Charges		5.5	6.0	0.5	5.6	5.7	0.1	6.0	6.3	0.4	6.5	6.5	6.6
18	Dismantling Expenses		67.0	67.0	0.0	43.0	43.0	(0.0)	45.5	45.5	(0.0)	53.3	46.3	44.8
19	EPA Terminations		0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
20	Other Provisions		0.0	3.4	3.4	0.0	16.7	16.7	0.0	0.0	0.0	0.0	0.0	0.0
21	First Nations Provisions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Total		116.4	128.7	12.4	95.4	110.7	15.3	101.4	97.8	(3.6)	104.9	96.7	95.3
	Regulatory Account Recoveries													
23	PCB Remediation		22.5	22.5	(0.0)	22.7	22.7	(0.0)	53.1	53.1	0.0	28.6	35.4	10.1
24	Asbestos Remediation		9.1	9.1	(0.0)	6.4	6.4	0.0	5.0	5.0	0.0	3.4	2.6	2.3
25	Dismantling Cost		25.5	25.5	(0.0)	24.6	24.6	0.0	(3.3)	(3.3)	0.0	(1.6)	(1.6)	(1.5)
26	Rock Bay Remediation		(10.8)	(10.8)	(0.0)	(10.4)	(10.4)	0.0	(0.1)	(0.1)	0.0	0.0	0.0	0.0
27	Project Write-Off Costs		0.0	0.0	0.0	0.0	0.0	0.0	9.3	9.3	0.0	2.5	2.5	2.5
28	Total		46.3	46.3	(0.0)	43.3	43.3	0.0	63.9	63.9	0.0	32.9	38.9	13.3
29	**Total Current Provisions & Other**	L22 + L28	162.6	175.0	12.4	138.7	154.0	15.3	165.3	161.7	(3.6)	137.8	135.6	108.6
	Current Provisions & Other By Function													
30	Generation		51.1	55.0	3.9	24.8	23.4	(1.3)	15.1	15.0	(0.1)	18.6	11.8	14.4
31	Transmission		33.8	48.7	14.9	37.3	31.1	(6.2)	62.8	61.5	(1.3)	53.6	59.2	32.8
32	Distribution		76.4	78.0	1.6	76.1	74.3	(1.7)	74.2	73.7	(0.5)	51.9	51.5	49.6
33	Customer Care		0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
34	Business Unit Support		1.3	(6.8)	(8.1)	0.6	25.1	24.5	13.2	11.5	(1.7)	13.7	13.1	11.9
35	**Total**		162.6	175.0	12.4	138.7	154.0	15.3	165.3	161.7	(3.6)	137.8	135.6	108.6
	Deferral Account Additions													
36	Transfers to NHDA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Provisions & Other - Total Company
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Regulatory Account Additions													
38	First Nations Provisions		0.0	0.9	0.9	0.0	1.2	1.2	0.0	(4.5)	(4.5)	0.0	0.0	0.0
39	Environmental Provisions		0.0	51.2	51.2	0.0	51.2	51.2	0.0	(0.8)	(0.8)	0.0	0.0	0.0
40	Smart Metering & Infrastructure DSMD Write-Off		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Real Property Sales		0.0	4.4	4.4	(0.0)	(12.0)	(12.0)	0.0	0.0	0.0	0.0	0.0	0.0
42	Dismantling Expenses		0.0	(8.5)	(8.5)	0.0	(3.8)	(3.8)	0.0	4.9	4.9	0.0	0.0	0.0
43	Project Write-Off Costs		0.0	0.0	0.0	0.0	16.4	16.4	0.0	0.0	0.0	0.0	0.0	0.0
44	Total		0.0	48.0	48.0	(0.0)	53.0	53.0	0.0	(0.4)	(0.4)	0.0	0.0	0.0
45	**Total Gross Provisions & Other**	L22 + L37 + L44	116.4	176.8	60.4	95.4	163.7	68.3	101.4	97.4	(4.0)	104.9	96.7	95.3
	Provisions & Other - Functional Allocation:													
	Gain/loss on Capital and Intangible Assets													
46	Generation		4.1	8.1	3.9	4.4	3.1	(1.4)	4.4	4.2	(0.1)	4.0	4.1	3.8
47	Transmission		7.0	7.7	0.8	7.3	8.4	1.1	7.7	6.4	(1.3)	6.0	5.6	6.0
48	Distribution		27.2	27.9	0.6	29.5	27.4	(2.1)	31.9	31.4	(0.5)	30.2	29.1	30.2
49	Business Unit Support		5.5	3.4	(2.2)	5.6	3.3	(2.3)	6.0	3.9	(2.1)	4.8	5.1	3.8
50	Subtotal		43.9	47.0	3.2	46.8	42.2	(4.6)	50.0	46.0	(4.0)	45.1	43.9	43.9
	Gain/Loss on Project Write-offs													
51	Generation		0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
52	Transmission		0.0	14.0	14.0	0.0	(7.3)	(7.3)	0.0	0.0	0.0	0.0	0.0	0.0
53	Distribution		0.0	0.8	0.8	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0
54	Business Unit Support		0.0	0.2	0.2	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
55	Subtotal		-	15.3	15.3	-	(6.9)	(6.9)	-	-	-	-	-	-
	Property Sales													
56	Business Unit Support		-	(10.0)	(10.0)	0.0	10.0	10.0	-	0.0	-	0.0	0.0	0.0
57	Subtotal		-	(10.0)	(10.0)	0.0	10.0	10.0	-	0.0	-	0.0	0.0	0.0
	Bank Charges													
58	Business Unit Support		5.5	6.0	0.5	5.6	5.7	0.1	6.0	6.3	0.4	6.5	6.5	6.6
59	Subtotal		5.5	6.0	0.5	5.6	5.7	0.1	6.0	6.3	0.4	6.5	6.5	6.6
	Dismantling Expenses													
60	Generation		32.4	32.4	0.0	7.8	7.8	0.0	9.1	9.1	0.0	10.3	5.1	8.9
61	Transmission		10.2	10.2	0.0	14.2	14.2	0.0	10.6	10.6	0.0	20.3	19.2	16.9
62	Distribution		22.8	22.8	0.0	20.6	20.6	0.0	25.7	25.7	0.0	21.7	21.7	18.2
63	Business Unit Support		1.6	1.6	0.0	0.4	0.4	0.0	0.2	0.2	0.0	1.0	0.3	0.8
64	Subtotal		67.0	67.0	-	43.0	43.0	-	45.5	45.5	-	53.3	46.3	44.8
	EPA Terminations													
65	Customer Care		-	-	-	0.0	(0.0)	(0.0)	-	0.0	-	0.0	0.0	0.0
66	Subtotal		-	-	-	0.0	(0.0)	(0.0)	-	0.0	-	0.0	0.0	0.0
	Other Provision													
67	Business Unit Support		-	3.4	3.4	0.0	16.7	16.7	-	0.0	-	0.0	0.0	0.0
68	Subtotal		-	3.4	3.4	0.0	16.7	16.7	-	0.0	-	0.0	0.0	0.0
	First Nations Provision													
69	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Provisions & Other - Total Company
($ million)

Line		Reference Column	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
70	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
71	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
72	Business Unit Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
73	Subtotal		-	-	-	0.0	0.0	-	-	0.0	-	0.0	0.0	0.0
	Provisions & Other By Function													
74	**Generation**		**36.6**	**40.8**	**4.2**	**12.3**	**10.9**	**(1.3)**	**13.4**	**13.3**	**(0.1)**	**14.4**	**9.2**	**12.7**
75	**Transmission**		**17.2**	**32.0**	**14.8**	**21.4**	**15.3**	**(6.2)**	**18.3**	**17.0**	**(1.3)**	**26.3**	**24.8**	**22.9**
76	**Distribution**		**50.0**	**51.5**	**1.5**	**50.1**	**48.3**	**(1.7)**	**57.6**	**57.1**	**(0.5)**	**51.9**	**50.8**	**48.4**
77	**Customer Care**		**-**	**-**	**-**	**0.0**	**(0.0)**	**(0.0)**	**-**	**0.0**	**-**	**0.0**	**0.0**	**0.0**
78	**Business Unit Support**		**12.6**	**4.5**	**(8.1)**	**11.6**	**36.1**	**24.5**	**12.1**	**10.4**	**(1.7)**	**12.3**	**11.9**	**11.3**
79	**Subtotal**		**116.4**	**128.7**	**12.4**	**95.4**	**110.7**	**15.3**	**101.4**	**97.8**	**(3.6)**	**104.9**	**96.7**	**95.3**
	Regulatory Account Recoveries - Functional Allocation:													
	PCB Remediation													
80	Generation		0.9	0.6	(0.3)	0.7	0.7	0.0	1.6	1.6	0.0	1.9	0.4	0.2
81	Transmission		8.3	8.4	0.2	8.1	8.1	(0.0)	24.0	24.0	0.0	16.8	21.4	5.9
82	Transmission	incl. D-SDA	4.9	4.9	0.0	4.8	4.8	0.0	13.2	13.2	0.0	9.0	11.7	2.2
83	Distribution		8.5	8.6	0.1	9.2	9.2	(0.0)	12.9	12.9	0.0	0.5	1.3	1.7
84	Business Unit Support		0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.4	0.0	0.5	0.5	(0.1)
85	Subtotal		22.5	22.5	(0.0)	22.7	22.7	(0.0)	53.1	53.1	-	28.6	35.4	10.1
	Asbestos Remediation													
86	Generation		2.2	2.2	(0.0)	0.7	0.7	0.0	1.0	1.0	0.0	2.2	2.1	1.2
87	Transmission		1.9	1.9	(0.0)	1.5	1.5	0.0	3.4	3.4	0.0	0.8	0.6	1.0
88	Distribution		4.8	4.8	(0.0)	4.2	4.2	0.0	0.5	0.5	0.0	0.7	0.4	0.4
89	Business Unit Support		0.2	0.2	(0.0)	0.0	0.0	0.0	0.1	0.1	0.0	(0.3)	(0.5)	(0.4)
90	Subtotal		9.1	9.1	(0.0)	6.4	6.4	0.0	5.0	5.0	-	3.4	2.6	2.3
	Dismantling Cost													
91	Generation		11.5	11.5	0.0	11.1	11.1	0.0	(1.8)	(1.8)	0.0	(0.7)	(0.7)	(0.7)
92	Transmission		1.5	1.5	0.0	1.5	1.5	0.0	(4.5)	(4.5)	0.0	0.7	0.7	0.7
93	Distribution		13.1	13.1	0.0	12.7	12.7	0.0	3.5	3.5	0.0	(2.6)	(2.5)	(2.4)
94	Business Unit Support		(0.7)	(0.7)	0.0	(0.7)	(0.7)	0.0	(0.6)	(0.6)	0.0	1.0	1.0	0.9
95	Subtotal		25.5	25.5	-	24.6	24.6	-	(3.3)	(3.3)	-	(1.6)	(1.6)	(1.5)
	Rock Bay Remediation													
96	Business Unit Support		(10.8)	(10.8)	(0.0)	(10.4)	(10.4)	0.0	(0.1)	(0.1)	-	0.0	0.0	0.0
97	Subtotal		(10.8)	(10.8)	(0.0)	(10.4)	(10.4)	0.0	(0.1)	(0.1)	-	0.0	0.0	0.0
	Project Write-Off Costs													
98	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.9	0.0	0.9	0.9	0.9
99	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	8.5	8.5	0.0	0.0	0.0	0.0
100	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	(0.4)	(0.4)	0.0	1.4	1.4	1.4
101	Business Unit Support		0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.2	0.2	0.2
102	Subtotal		-	-	-	-	-	-	9.3	9.3	-	2.5	2.5	2.5
	Regulatory Account Recoveries By Function													
102	**Generation**		**14.6**	**14.3**	**(0.3)**	**12.5**	**12.5**	**0.0**	**1.7**	**1.7**	**-**	**4.2**	**2.7**	**1.7**
103	**Transmission**		**16.6**	**16.7**	**0.2**	**15.9**	**15.9**	**0.0**	**44.5**	**44.5**	**-**	**27.3**	**34.4**	**9.9**
104	**Distribution**		**26.4**	**26.6**	**0.1**	**26.0**	**26.0**	**0.0**	**16.6**	**16.6**	**-**	**0.0**	**0.6**	**1.2**
105	**Customer Care**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

BC Hydro
F23-F25 RRA

Schedule 5.01
Page 42

Provisions & Other - Total Company
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
Line	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
106	**Business Unit Support**		**(11.3)**	**(11.3)**	**(0.0)**	**(11.1)**	**(11.1)**	**0.0**	**1.1**	**1.1**	**-**	**1.4**	**1.2**	**0.6**
107	**Subtotal**		**46.3**	**46.3**	**(0.0)**	**43.3**	**43.3**	**0.0**	**63.9**	**63.9**	**-**	**32.9**	**38.9**	**13.3**
	Provisions & Other Continuity													
108	Provisions & Other	Line 22	116.4	128.7	12.4	95.4	110.7	15.3	101.4	97.8	(3.6)	104.9	96.7	95.3
109	Deferral Account Additions and Regulatory Account Additions	L37 + L44	0.0	48.0	48.0	(0.0)	53.0	53.0	0.0	(0.4)	(0.4)	0.0	0.0	0.0
110	**Gross Provisions & Other**	Line 45	**116.4**	**176.8**	**60.4**	**95.4**	**163.7**	**68.3**	**101.4**	**97.4**	**(4.0)**	**104.9**	**96.7**	**95.3**
111	Reverse Deferral Account Additions and Regulatory Account Additions	Line 109	0.0	(48.0)	(48.0)	0.0	(53.0)	(53.0)	0.0	0.4	0.4	0.0	0.0	0.0
112														
113	Regulatory Account Recoveries	Line 28	46.3	46.3	(0.0)	43.3	43.3	0.0	63.9	63.9	0.0	32.9	38.9	13.3
114	**Current Provisions & Other**	Line 29	**162.6**	**175.0**	**12.4**	**138.7**	**154.0**	**15.3**	**165.3**	**161.7**	**(3.6)**	**137.8**	**135.6**	**108.6**

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line	Column	Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Gross Operating Costs Including Regulatory													
1	Labour (excl Non-Current PEB)	L115 + L123	617.0	623.0	6.0	627.2	644.9	17.7	678.2	660.1	(18.2)	687.0	707.8	731.1
2	Services - ABSU	L116 + L124	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
3	Services - Other	L117 + L125	513.3	475.8	(37.5)	501.0	464.4	(36.5)	548.7	556.7	8.0	573.1	579.2	590.2
4	Materials	L118 + L126	46.6	54.2	7.7	46.5	47.0	0.4	49.7	46.7	(3.0)	50.0	49.9	49.8
5	Buildings & Equipment	L119 + L127	52.2	63.8	11.6	52.1	65.5	13.4	52.2	55.3	3.1	75.5	75.9	76.0
			1,229.2	1,216.9	(12.3)	1,226.8	1,221.8	(5.1)	1,328.8	1,318.7	(10.1)	1,385.6	1,412.8	1,447.2
	Less:													
6	Eligible Capital Overhead	L120 + L130	(71.0)	(72.0)	(1.1)	(71.4)	(71.5)	(0.2)	(75.5)	(75.7)	(0.2)	(76.2)	(76.2)	(76.4)
7	External Recoveries	L121 + L128	(22.1)	(29.6)	(7.5)	(20.1)	(21.5)	(1.4)	(26.6)	(24.4)	2.2	(22.6)	(22.2)	(22.3)
8	**Total Gross Operating Costs Including Regulatory Account Additions**	5.0 L74	**1,136.1**	**1,115.2**	**(20.9)**	**1,135.4**	**1,128.7**	**(6.6)**	**1,226.7**	**1,218.6**	**(8.1)**	**1,286.8**	**1,314.4**	**1,348.4**
9	**Total Gross Provision & Other Including Regulatory Account Additions**	5.01 L45	116.4	176.8	60.4	95.4	163.7	68.3	101.4	97.4	(4.0)	104.9	96.7	95.3
10	**Total Gross Operating Cost and Provision & Other Including Regulatory Account Additions**		**1,252.5**	**1,292.0**	**39.5**	**1,230.8**	**1,292.4**	**61.7**	**1,328.1**	**1,315.9**	**(12.2)**	**1,391.6**	**1,411.1**	**1,443.8**
	Less Operating Costs Reg. Acct. Additions													
	Demand-Side Management													
11	Labour		**(23.3)**	**(22.5)**	0.8	**(23.2)**	**(22.8)**	0.4	**(25.3)**	**(25.3)**	(0.0)	**(27.3)**	**(27.9)**	**(28.7)**
12	Services - ABSU		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
13	Services - Other		**(84.8)**	**(71.6)**	13.1	**(74.7)**	**(57.6)**	17.1	**(71.6)**	**(68.8)**	2.8	**(100.4)**	**(105.9)**	**(108.4)**
14	Materials		**(0.3)**	**(0.2)**	0.0	**(0.3)**	**(0.2)**	0.1	**(0.2)**	**(0.3)**	(0.1)	**(0.2)**	**(0.2)**	**(0.2)**
15	Buildings & Equipment		**(0.8)**	**(1.1)**	(0.3)	**(0.6)**	**(0.5)**	0.0	**(0.7)**	**(0.7)**	(0.0)	**(0.7)**	**(0.7)**	**(0.4)**
16	F17-F19 RRA Compliance Filing Adjustment		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
	First Nations Costs													
17	Labour		**(0.9)**	**(1.0)**	(0.1)	**(0.8)**	**(1.2)**	(0.4)	**(1.2)**	**(1.2)**	0.0	**(1.0)**	**(1.0)**	**(1.0)**
18	Services - ABSU		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
19	Services - Other		**(2.3)**	**(1.5)**	0.8	**(1.6)**	**(0.6)**	1.0	**(0.9)**	**(0.8)**	0.0	**(0.8)**	**(0.8)**	**(0.8)**
20	Materials		**0.0**	**(0.0)**	(0.0)	**0.0**	**(0.0)**	(0.0)	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
21	Buildings & Equipment		**0.0**	**(0.0)**	(0.0)	**0.0**	**(0.0)**	(0.0)	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
	Site C Project													
22	Labour		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
23	Services - ABSU		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
24	Services - Other		**(0.3)**	**(0.3)**	0.0	**(0.3)**	**(0.3)**	0.0	**(0.3)**	**(0.3)**	(0.0)	**(0.3)**	**(0.3)**	**(0.3)**
25	Materials		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
26	Buildings & Equipment		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
	Storm Restoration													
27	Labour		**0.0**	**0.9**	0.9	**0.0**	**3.0**	3.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
28	Services - ABSU		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
29	Services - Other		**0.0**	**6.6**	6.6	**0.0**	**11.0**	11.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
30	Materials		**0.0**	**0.3**	0.3	**0.0**	**0.2**	0.2	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
31	Buildings & Equipment		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
	Smart Metering & Infrastructure													
32	Labour		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
33	Services - ABSU		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
34	Services - Other		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**
35	Materials		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	**0.0**

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
Column			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Gross Operating Costs Including Regulatory													
36	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	External Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Pension Cost													
38	Labour		0.0	0.9	0.9	0.0	5.8	5.8	0.0	24.8	24.8	0.0	0.0	0.0
39	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	Services - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Real Property Sales													
43	Labour		0.0	(0.3)	(0.3)	0.0	(0.1)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0
44	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Services - Other		0.0	(0.6)	(0.6)	0.0	(1.0)	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0
46	Materials		0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
47	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Customer Crisis Fund													
48	Labour		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
50	Services - Other		0.3	2.7	2.4	0.3	(0.9)	(1.2)	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0
51	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
52	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	**Electric Vehicle Costs**													
54	Labour		(0.7)	0.0	0.7	(0.7)	(1.4)	(0.7)	0.0	(1.0)	(1.0)	0.0	0.0	0.0
55	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
56	Services - Other		(1.2)	0.0	1.2	(1.0)	(1.9)	(0.9)	0.0	(1.1)	(1.1)	0.0	0.0	0.0
57	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
58	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Mining Customer Payment Plan													
59	Labour		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
60	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
61	Services - Other		0.0	0.0	0.0	0.0	(0.7)	(0.7)	0.0	0.0	0.0	0.0	0.0	0.0
62	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
63	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Mandatory Reliability Standard Costs													
64	Labour		0.0	0.0	0.0	0.0	0.0	0.0	0.0	(4.0)	(4.0)	0.0	0.0	0.0
65	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	Services - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	(11.9)	(11.9)	0.0	0.0	0.0
67	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
68	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Load Attraction Costs													
69	Labour		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.8)	(1.8)	(1.9)
70	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
71	Services - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(6.9)	(7.8)	(6.9)
72	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
73	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
74	**IFRS Capitalized Overhead**	5.0 L65	(44.8)	(44.8)	0.0	(22.4)	(22.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
75	**Total Operating Costs Reg. Acct. Additions**	5.0 L73	(159.0)	(132.6)	26.4	(125.4)	(91.8)	33.6	(100.2)	(90.7)	9.5	(139.4)	(146.4)	(148.6)

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line	Column	Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Gross Operating Costs Including Regulatory													
	Less Provisions Reg. Acct. Additions													
76	First Nations Provisions	5.01 L38	0.0	(0.9)	(0.9)	0.0	(1.2)	(1.2)	0.0	4.5	4.5	0.0	0.0	0.0
77	Environmental Provisions	5.01 L39	0.0	(51.2)	(51.2)	0.0	(51.2)	(51.2)	0.0	0.8	0.8	0.0	0.0	0.0
78	Smart Metering & Infrastructure DSMD Write-Off	5.01 L40	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
79	Real Property Sales	5.01 L41	0.0	(4.4)	(4.4)	0.0	12.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0
80	Dismantling Cost	5.01 L42	0.0	8.5	8.5	0.0	3.8	3.8	0.0	(4.9)	(4.9)	0.0	0.0	0.0
81	Project Write-Off Costs	5.01 L43	0.0	0.0	0.0	0.0	(16.4)	(16.4)	0.0	0.0	0.0	0.0	0.0	0.0
82	**Total Provisions Reg. Acct. Additions**	5.01 L44	0.0	(48.0)	(48.0)	0.0	(53.0)	(53.0)	0.0	0.4	0.4	0.0	0.0	0.0
83	**Total Regulatory Account Additions**	L75 + L82 (or 3.0 L8+L14)	(159.0)	(180.6)	(21.6)	(125.4)	(144.8)	(19.5)	(100.2)	(90.3)	9.9	(139.4)	(146.4)	(148.6)
	Less Operating Costs Def. Acct. Additions													
	Transfers to HDA													
84	Labour		0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
85	Services - Other		0.0	1.3	1.3	0.0	1.5	1.5	0.0	(0.7)	(0.7)	0.0	0.0	0.0
86	Materials		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Transfers to NHDA													
87	Labour		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
88	Services - Other		0.0	0.0	0.0	0.0	(1.5)	(1.5)	0.0	(0.6)	(0.6)	0.0	0.0	0.0
89	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Less Provisions Def. Acct. Additions													
	Transfers to NHDA													
90	Provision & Other	5.01 L36	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
91	**Total Deferral Account Additions**	5.0 L58+5.01 L37 (or 3.0 L7+L13)	0.0	1.4	1.4	0.0	0.0	0.0	0.0	(1.4)	(1.4)	0.0	0.0	0.0
	Add Regulatory Account Recoveries													
92	First Nation Costs	5.0 L28	34.7	34.1	(0.6)	33.7	33.1	(0.5)	34.4	34.4	(0.0)	34.1	33.9	16.6
93	Storm Restoration	5.0 L29	30.6	30.6	0.0	29.5	29.5	0.0	(12.9)	(12.9)	0.0	(3.8)	(3.7)	(3.6)
94	Capital Project Investigation	5.0 L30	5.2	5.2	0.0	5.2	5.2	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
95	Smart Metering & Infrastructure	5.0 L31	29.4	29.6	0.2	28.5	28.6	0.2	26.6	26.6	0.0	25.8	25.1	24.6
96	Non-Current Pension Cost	5.0 L32	51.4	56.8	5.4	51.4	46.0	(5.4)	114.6	114.6	0.0	29.7	29.7	29.7
97	PEB Current Pension Costs	5.0 L33	(0.9)	(0.9)	0.0	(0.9)	(0.9)	0.0	(6.7)	(6.7)	0.0	(8.3)	(8.3)	(8.3)
98	IFRS PP&E	5.0 L34	29.9	29.9	0.0	31.0	31.0	0.0	31.6	31.6	0.0	31.6	31.6	31.6
99	IFRS Pension	5.0 L35	38.2	38.2	(0.0)	38.2	38.2	(0.0)	38.2	38.2	0.0	38.2	38.2	38.2
100	Electric Vehicle Costs	5.0 L36	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	2.6	2.5
101	Customer Crisis Fund	5.0 L37	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.6	14.2	13.8
102	Mining Customer Payment Plan	5.0 L38	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	2.6	2.5
103	Mandatory Reliability Standard Costs	5.0 L39:L41	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.8	5.6	5.5
104	Load Attraction Costs	5.0 L42	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.8	1.6
105	Site C Project	5.0 L43	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6
106	**Total Regulatory Account Recoveries (Operating Costs)**	5.0 L44	218.7	223.6	4.9	216.7	210.9	(5.8)	225.8	225.8	(0.0)	173.2	172.3	160.3
107	Remediation (PCB)	5.01 L23	22.5	22.5	(0.0)	22.7	22.7	(0.0)	53.1	53.1	0.0	28.6	35.4	10.1
108	Remediation (Asbestos)	5.01 L24	9.1	9.1	(0.0)	6.4	6.4	0.0	5.0	5.0	0.0	3.4	2.6	2.3
109	Dismantling Expense	5.01 L25	25.5	25.5	(0.0)	24.6	24.6	0.0	(3.3)	(3.3)	0.0	(1.6)	(1.6)	(1.5)
110	Rock Bay Remediation	5.01 L26	(10.8)	(10.8)	(0.0)	(10.4)	(10.4)	0.0	(0.1)	(0.1)	0.0	0.0	0.0	0.0
111	Project Write-Off Costs	5.01 L27	0.0	0.0	0.0	0.0	0.0	0.0	9.3	9.3	0.0	2.5	2.5	2.5
112	**Total Regulatory Account Recoveries (Provisions & Other)**	5.01 L28	46.3	46.3	(0.0)	43.3	43.3	0.0	63.9	63.9	0.0	32.9	38.9	13.3

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line		Reference	F2020			F2021			F2022			F2023	F2024	F2025
			Decision	Actual	Diff	Decision	Actual	Diff	Decision	Forecast	Diff	Plan	Plan	Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Gross Operating Costs Including Regulatory													
113	**Total Regulatory Account Recoveries**	L106 + L112 (or 3.0 L10+L16)	264.9	269.8	4.9	260.0	254.2	(5.8)	289.7	289.7	(0.0)	206.1	211.2	173.6
114	**Total Current Operating Costs & Provisions & Other**	5.0 L55 + 5.01 L29 (or 3.0 L11+L17)	**1,358.4**	**1,382.6**	**24.2**	**1,365.4**	**1,401.8**	**36.5**	**1,517.7**	**1,514.0**	**(3.6)**	**1,458.3**	**1,475.9**	**1,468.8**
	SUMMARY OF OPERATING COSTS ABOVE													
	Operating Costs Before Deferrals													
115	Labour (excl Non-Current PEB)	5.0 L20	592.2	601.1	8.9	602.4	628.2	25.8	651.7	653.3	1.5	656.8	677.1	699.5
116	Services - ABSU	5.0 L21	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
117	Services - Other	5.0 L22	425.0	412.4	(12.7)	423.6	412.3	(11.3)	475.9	472.4	(3.6)	464.7	464.2	473.9
118	Materials	5.0 L23	46.3	54.3	8.0	46.3	47.0	0.7	49.5	46.4	(3.1)	49.8	49.7	49.6
119	Buildings & Equipment	5.0 L24	51.4	62.7	11.3	51.5	64.9	13.3	51.5	54.6	3.1	74.9	75.3	75.6
	Less:													
120	Capital Overhead	5.0 L25	(115.8)	(116.9)	(1.1)	(93.8)	(93.9)	(0.2)	(75.5)	(75.7)	(0.2)	(76.2)	(76.2)	(76.4)
121	External Recoveries	5.0 L26	(22.1)	(29.6)	(7.5)	(20.1)	(21.5)	(1.4)	(26.6)	(24.4)	2.2	(22.6)	(22.2)	(22.3)
122	**Total Operating Costs Before Deferrals**	5.0 L27	**977.1**	**984.0**	**6.9**	**1,010.0**	**1,037.0**	**27.0**	**1,126.5**	**1,126.5**	**0.0**	**1,147.4**	**1,167.9**	**1,199.9**
	Deferred Operating Costs													
123	Labour (excl Non-Current PEB)	-(L11 + L17 + L22 + L27 + L32 + L38 + L43 + L48 + L54 + L59 + L64 + L69 + L84 + L87)	24.9	21.9	(2.9)	24.8	16.7	(8.1)	26.5	6.8	(19.7)	30.2	30.7	31.6
124	Services - ABSU	-(L12 + L18 + L23 + L28 + L33 + L39 + L44 + L49 + L55 + L60 + L65 + L70)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
125	Services - Other	-(L13 + L19 + L24 + L29 + L34 + L40 + L45 + L50 + L56 + L61 + L66 + L71 + L85 + L88)	88.3	63.5	(24.8)	77.4	52.1	(25.2)	72.8	84.4	11.5	108.4	114.9	116.4
126	Materials	-(L14 + L20 + L25 + L30 + L35 + L41 + L46 + L51 + L57 + L62 + L67 + L72 + L86 + L89)	0.3	(0.1)	(0.3)	0.3	(0.0)	(0.3)	0.2	0.3	0.1	0.2	0.2	0.2
127	Buildings & Equipment	-(L15 + L21 + L26 + L31 + L36 + L42 + L47 + L52 + L58 + L63 + L68 + L73)	0.8	1.1	0.3	0.6	0.6	0.0	0.7	0.7	0.0	0.7	0.7	0.4
128	External Recoveries	- L37	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
129	**Total Deferred Operating Costs**		**114.2**	**86.4**	**(27.8)**	**103.0**	**69.4**	**(33.6)**	**100.2**	**92.1**	**(8.1)**	**139.4**	**146.4**	**148.6**
130	**IFRS Capitalized Overhead**	5.0 L65	44.8	44.8	0.0	22.4	22.4	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
131	**Total Operating Costs Including Deferrals**	Line 8	**1,136.1**	**1,115.2**	**(20.9)**	**1,135.4**	**1,128.7**	**(6.6)**	**1,226.7**	**1,218.6**	**(8.1)**	**1,286.8**	**1,314.4**	**1,348.4**
132	**Provisions & Other**	Line 9	116.4	176.8	60.4	95.4	163.7	68.3	101.4	97.4	(4.0)	104.9	96.7	95.3
133	**Total Gross Operating Cost and Provision & Other Including Deferrals**	Line 10	**1,252.5**	**1,292.0**	**39.5**	**1,230.8**	**1,292.4**	**61.7**	**1,328.1**	**1,315.9**	**(12.2)**	**1,391.6**	**1,411.1**	**1,443.8**
	Less													
134	**Deferral Account Additions**	L75 + L91	(159.0)	(131.2)	27.8	(125.4)	(91.8)	33.6	(100.2)	(92.1)	8.1	(139.4)	(146.4)	(148.6)
135	**Deferred Provisions & Other**	Line 82	0.0	(48.0)	(48.0)	0.0	(53.0)	(53.0)	0.0	0.4	0.4	0.0	0.0	0.0
	Add													
136	**Regulatory Account Recoveries Bf Provisions & Other**	Line 106	218.7	223.6	4.9	216.7	210.9	(5.8)	225.8	225.8	(0.0)	173.2	172.3	160.3

BC Hydro
F23-F25 RRA

Schedule 5S
Page 47

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line	Column	Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
137	Gross Operating Costs Including Regulatory Provisions & Other Regulatory Account Recoveries	Line 112	46.3	46.3	(0.0)	43.3	43.3	0.0	63.9	63.9	0.0	32.9	38.9	13.3
138	**Total Current Operating Costs & Provisions & Other**	Line 114	**1,358.4**	**1,382.6**	**24.2**	**1,365.4**	**1,401.8**	**36.5**	**1,517.7**	**1,514.0**	**(3.6)**	**1,458.3**	**1,475.9**	**1,468.8**
139	**Current Operating Costs**	L122 + L136	**1,195.8**	**1,207.6**	**11.8**	**1,226.7**	**1,247.9**	**21.2**	**1,352.3**	**1,352.3**	**(0.0)**	**1,320.5**	**1,340.3**	**1,360.2**

BC Hydro
F23-F25 RRA

Schedule 5.1
Page 48

Operating Costs - Integrated Planning
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Operating Costs by KBU													
1	Energy Planning and Analytics		7.9	8.2	0.2	8.4	8.8	0.5	9.0	9.0	(0.0)	9.1	8.7	9.4
2	Dam Safety		10.2	9.8	(0.4)	10.3	10.4	0.0	11.4	11.4	0.0	11.2	11.4	11.9
3	Asset Planning		223.5	226.2	2.7	225.8	236.8	11.1	270.4	271.2	0.8	278.9	286.3	294.1
4	Interconnections and Shared Assets		10.5	13.1	2.6	10.6	15.4	4.8	13.1	13.1	(0.0)	14.7	14.1	14.2
5	Engineering Design		19.1	18.7	(0.4)	19.4	17.3	(2.2)	18.2	18.1	(0.2)	18.3	18.4	18.9
6	Engineering Services		5.5	5.3	(0.2)	5.6	7.2	1.6	9.0	9.2	0.2	9.0	9.3	9.5
7	Business Unit Support		15.9	11.1	(4.8)	15.1	16.0	0.9	15.9	15.9	(0.0)	16.3	16.5	22.5
8	**Base Operating Costs**		292.7	292.5	(0.3)	295.2	311.9	16.6	346.9	347.8	0.9	357.6	364.6	380.4
9	IFRS Ineligible Capitalized Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Waneta 2/3	15.0 L27	5.7	5.4	(0.3)	5.9	5.8	(0.0)	6.1	6.1	0.0	5.9	6.1	6.3
11	Customer Crisis Fund		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Total Base Operating Costs Adjustment**		5.7	5.4	(0.3)	5.9	5.8	(0.0)	6.1	6.1	0.0	5.9	6.1	6.3
13	**Net Operating Costs**		298.4	297.8	(0.6)	301.1	317.7	16.6	353.0	353.9	0.9	363.5	370.7	386.7
	Operating Costs by Resource													
14	Labour		147.6	154.2	6.7	149.7	167.6	17.9	165.8	167.7	1.9	171.6	175.9	182.7
15	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Services - Other		149.1	132.4	(16.7)	149.6	138.3	(11.3)	183.0	183.6	0.7	170.7	174.0	183.9
17	Materials		11.2	13.3	2.1	11.2	13.3	2.1	15.1	13.6	(1.4)	17.1	17.2	17.2
18	Buildings & Equipment		2.5	12.4	9.9	2.5	11.7	9.2	1.9	2.0	0.2	17.5	17.5	17.6
19	Capitalized Overhead		0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	External Recoveries		(11.9)	(14.6)	(2.7)	(11.9)	(13.3)	(1.4)	(12.7)	(13.1)	(0.4)	(13.4)	(13.9)	(14.7)
21	Total		298.4	297.8	(0.6)	301.1	317.7	16.6	353.0	353.9	0.9	363.5	370.7	386.7

BC Hydro
F23-F25 RRA

Schedule 5.2
Page 49

Operating Costs - Capital Infrastructure Project Delivery
($ million)

Line		F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Reference Column	1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Operating Costs by KBU												
1	Project Delivery	14.0	13.9	(0.1)	14.5	13.2	(1.3)	15.4	15.2	(0.2)	15.2	15.5	15.9
2	Indigenous Relations	6.1	6.1	(0.1)	6.3	7.4	1.2	6.7	6.7	(0.0)	8.1	8.6	8.8
3	Environment	29.8	29.4	(0.4)	30.0	28.9	(1.1)	31.0	30.6	(0.4)	30.7	31.0	31.4
4	Properties	29.3	30.0	0.7	29.5	30.5	1.0	30.3	30.2	(0.0)	30.0	30.3	30.5
5	Business Unit Support	0.8	0.8	(0.0)	0.9	0.8	(0.1)	0.9	0.9	0.0	0.9	0.9	0.9
6	**Base Operating Costs**	80.1	80.1	0.1	81.1	80.8	(0.3)	84.3	83.7	(0.6)	84.8	86.3	87.6
7	IFRS Ineligible Capitalized Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Total Base Operating Costs Adjustment**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Net Operating Costs**	80.1	80.1	0.1	81.1	80.8	(0.3)	84.3	83.7	(0.6)	84.8	86.3	87.6
	Operating Costs by Resource												
12	Labour	34.1	33.8	(0.3)	35.1	34.7	(0.5)	38.1	38.4	0.3	38.2	39.2	40.4
13	Services - ABSU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Services - Other	51.5	52.6	1.1	49.4	49.4	(0.0)	56.0	52.5	(3.5)	52.0	51.4	50.8
15	Materials	1.1	0.4	(0.6)	1.1	0.9	(0.1)	0.4	0.5	0.0	0.5	0.5	0.5
16	Buildings & Equipment	3.6	3.7	0.1	3.7	3.6	(0.1)	3.6	3.6	(0.0)	3.5	3.5	3.5
17	Capitalized Overhead	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	External Recoveries	(10.2)	(10.3)	(0.1)	(8.2)	(7.9)	0.3	(13.9)	(11.3)	2.6	(9.2)	(8.2)	(7.6)
19	Total	80.1	80.1	0.1	81.1	80.8	(0.3)	84.3	83.7	(0.6)	84.8	86.3	87.6

BC Hydro
F23-F25 RRA

Schedule 5.3
Page 50

Operating Costs - Operations
($ million)

Line		F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Reference Column	1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Operating Costs by KBU												
1	Program and Contract Management	14.0	16.2	2.2	14.2	14.4	0.1	17.3	18.1	0.8	19.2	19.7	20.2
2	Line Field Operations	85.9	87.0	1.1	86.7	103.1	16.4	92.3	92.6	0.4	92.2	91.8	92.1
3	Stations Field Operations	52.9	51.3	(1.6)	53.5	57.7	4.3	55.8	56.0	0.2	56.0	56.5	59.7
4	Distribution Design and Customer Connect	14.8	15.9	1.1	15.1	14.6	(0.4)	16.4	16.2	(0.3)	17.4	17.9	18.4
5	Construction Services	13.2	13.2	0.0	13.3	14.8	1.5	14.9	14.6	(0.2)	13.9	14.0	14.3
6	Generation System Operations	19.7	19.2	(0.5)	20.0	19.4	(0.5)	19.8	21.1	1.3	22.5	22.9	23.3
7	Transmission and Distribution System Operations	39.8	40.4	0.6	40.3	40.3	0.0	41.6	41.9	0.2	41.8	42.6	43.5
8	Business Unit Support	2.8	3.7	1.0	2.8	0.6	(2.2)	3.3	2.4	(0.9)	3.7	3.7	3.8
9	**Base Operating Costs**	243.0	246.9	3.9	245.8	265.0	19.2	261.4	262.8	1.4	266.8	269.2	275.3
10	IFRS Ineligible Capitalized Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**Total Base Operating Costs Adjustment**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	**Net Operating Costs**	243.0	246.9	3.9	245.8	265.0	19.2	261.4	262.8	1.4	266.8	269.2	275.3
	Operating Costs by Resource												
15	Labour	163.6	167.4	3.8	166.3	184.1	17.8	182.3	184.3	2.0	184.8	187.7	193.1
16	Services - ABSU	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
17	Services - Other	62.3	62.4	0.0	62.5	63.0	0.6	62.2	61.0	(1.2)	64.5	64.0	64.8
18	Materials	10.2	10.5	0.3	10.2	9.8	(0.4)	9.4	9.2	(0.1)	9.2	9.2	9.2
19	Buildings & Equipment	6.8	6.5	(0.3)	6.8	8.1	1.3	7.5	8.3	0.8	8.3	8.3	8.3
20	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	External Recoveries	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
22	Total	243.0	246.9	3.9	245.8	265.0	19.2	261.4	262.8	1.4	266.8	269.2	275.3

BC Hydro
F23-F25 RRA

Schedule 5.4
Page 51

Operating Costs - Safety & Compliance
($ million)

Line		Reference Column	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Operating Costs by KBU													
1	Safety		21.7	20.8	(0.8)	21.9	19.4	(2.6)	22.5	22.3	(0.2)	20.1	20.5	20.7
2	Learning and Development		23.8	21.3	(2.6)	24.2	19.2	(5.0)	24.5	24.1	(0.4)	23.9	25.3	27.0
3	Security and Emergency Management		10.7	12.3	1.6	10.8	16.4	5.7	12.5	12.4	(0.1)	12.6	13.8	14.4
4	Reliability Standards Assurance		1.0	1.4	0.4	1.0	8.0	7.0	8.1	6.8	(1.3)	8.3	5.9	5.2
5	Business Unit Support		0.6	0.6	(0.0)	0.6	0.7	0.1	0.8	0.7	(0.1)	0.6	0.7	0.7
6	**Base Operating Costs**		57.8	56.4	(1.4)	58.5	63.7	5.2	68.3	66.2	(2.1)	65.6	66.1	68.0
7	IFRS Ineligible Capitalized Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Waneta 2/3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Customer Crisis Fund		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Total Base Operating Costs Adjustment**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Net Operating Costs**		57.8	56.4	(1.4)	58.5	63.7	5.2	68.3	66.2	(2.1)	65.6	66.1	68.0
	Operating Costs by Resource													
12	Labour		38.7	37.1	(1.6)	39.4	40.0	0.7	45.7	42.1	(3.6)	42.6	45.9	48.5
13	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Services - Other		18.0	17.7	(0.3)	18.0	21.3	3.3	21.4	22.9	1.5	21.7	18.9	18.2
15	Materials		0.8	1.1	0.2	0.8	1.8	1.0	0.7	0.7	(0.0)	0.7	0.7	0.7
16	Buildings & Equipment		0.3	0.6	0.3	0.3	0.7	0.3	0.5	0.5	0.0	0.6	0.6	0.6
17	Capitalized Overhead		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	External Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Total		57.8	56.4	(1.4)	58.5	63.7	5.2	68.3	66.2	(2.1)	65.6	66.1	68.0

BC Hydro
F23-F25 RRA

Schedule 5.5
Page 52

Operating Costs - Finance, Technology, Supply Chain
($ million)

Line		F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Reference Column	1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Operating Costs by KBU												
1	Finance	31.6	31.6	0.0	32.1	46.0	13.9	51.0	51.0	(0.0)	51.1	52.5	54.0
2	Technology	135.8	138.4	2.6	136.4	137.8	1.4	146.3	148.4	2.1	157.9	162.4	164.0
3	Supply Chain	94.5	94.3	(0.2)	95.5	92.7	(2.7)	101.0	99.8	(1.2)	98.6	99.2	100.2
4	Business Unit Support	0.8	0.8	(0.0)	0.8	0.8	(0.0)	0.9	0.9	0.0	0.8	0.9	0.9
5	**Base Operating Costs**	262.6	265.1	2.5	264.8	277.3	12.5	299.1	300.0	0.9	308.4	314.9	319.1
6	IFRS Ineligible Capitalized Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**Total Base Operating Costs Adjustment**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Net Operating Costs**	262.6	265.1	2.5	264.8	277.3	12.5	299.1	300.0	0.9	308.4	314.9	319.1
	Operating Costs by Resource												
11	Labour	115.6	115.2	(0.5)	117.8	123.8	6.0	132.5	132.8	0.3	132.3	138.7	142.6
12	Services - ABSU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Services - Other	88.5	89.0	0.5	88.5	94.6	6.1	107.4	107.9	0.5	112.1	112.0	112.2
14	Materials	21.9	27.2	5.4	21.9	19.4	(2.5)	22.2	21.9	(0.3)	21.8	21.7	21.6
15	Buildings & Equipment	36.6	38.3	1.7	36.6	39.9	3.3	37.0	37.3	0.4	42.2	42.5	42.8
16	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	External Recoveries	0.0	(4.7)	(4.7)	0.0	(0.4)	(0.4)	0.0	0.0	0.0	0.0	0.0	0.0
18	Total	262.6	265.1	2.5	264.8	277.3	12.5	299.1	300.0	0.9	308.4	314.9	319.1

BC Hydro | **Schedule 5.6**
F23-F25 RRA | **Page 53**

Operating Costs - Customer and Corporate Affairs
($ million)

Line	Reference Column	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Operating Costs by KBU												
1	Customer Service	62.4	60.5	(1.9)	63.0	61.5	(1.5)	67.8	67.7	(0.1)	67.8	69.2	70.7
2	Conservation and Energy Management	0.6	0.6	(0.0)	0.6	0.5	(0.1)	0.7	0.7	(0.0)	0.6	0.7	0.7
3	Communications and Community Engagement	12.9	12.7	(0.2)	13.0	12.9	(0.2)	14.2	13.9	(0.3)	13.9	14.2	14.5
4	Regulatory and Rates	5.4	8.1	2.8	5.4	13.7	8.3	13.1	13.9	0.8	13.4	13.7	14.0
5	Business Unit Support	0.8	0.7	(0.1)	0.8	0.8	(0.0)	0.9	0.9	0.0	0.8	0.9	0.9
6	**Base Operating Costs**	82.1	82.6	0.6	82.9	89.4	6.5	96.6	97.0	0.4	96.6	98.6	100.8
7	IFRS Ineligible Capitalized Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Customer Crisis Fund	5.3	4.4	(0.9)	5.3	2.9	(2.4)	0.5	0.5	0.0	0.0	0.0	0.0
10	**Total Base Operating Costs Adjustment**	5.3	4.4	(0.9)	5.3	2.9	(2.4)	0.5	0.5	0.0	0.0	0.0	0.0
11	**Net Operating Costs**	87.4	87.0	(0.4)	88.2	92.4	4.1	97.1	97.5	0.4	96.6	98.6	100.8
	Operating Costs by Resource												
12	Labour	54.4	54.2	(0.3)	55.3	58.1	2.9	62.0	62.7	0.7	62.9	64.6	66.5
13	Services - ABSU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Services - Other	30.7	30.4	(0.3)	30.7	31.8	1.1	32.7	31.8	(0.9)	30.8	31.1	31.4
15	Materials	1.0	1.6	0.6	1.0	1.6	0.6	1.5	0.3	(1.2)	0.3	0.3	0.3
16	Buildings & Equipment	1.2	0.9	(0.4)	1.2	0.8	(0.5)	0.8	2.6	1.8	2.6	2.6	2.6
17	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	External Recoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Total	87.4	87.0	(0.4)	88.2	92.4	4.1	97.1	97.5	0.4	96.6	98.6	100.8

BC Hydro
F23-F25 RRA

Schedule 5.7
Page 54

Operating Costs - Other
($ million)

		F2020			F2021			F2022			F2023	F2024	F2025
	Reference	Decision	Actual	Diff	Decision	Actual	Diff	Decision	Forecast	Diff	Plan	Plan	Plan
Line	Column	1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Operating Costs by KBU												
1	Human Resources	22.1	22.0	(0.1)	22.4	21.0	(1.5)	24.4	23.8	(0.6)	23.6	24.1	24.6
2	Office of the General Counsel	11.7	12.0	0.3	11.8	15.5	3.7	13.0	13.0	0.0	12.9	12.9	12.8
3	Office of the President and Chief Executive Officer	0.9	0.8	(0.0)	0.9	0.8	(0.1)	0.9	0.9	0.0	0.9	0.9	0.9
4	Site C Project	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
5	Corporate Costs	28.9	32.7	3.8	29.1	(3.3)	(32.4)	0.5	0.5	0.0	0.5	0.5	0.5
6	Capitalized Costs	(285.8)	(287.0)	(1.2)	(286.2)	(286.4)	(0.1)	(290.4)	(290.6)	(0.2)	(291.1)	(291.1)	(291.3)
7	**Base Operating Costs**	(222.2)	(219.4)	2.8	(222.0)	(252.4)	(30.4)	(251.6)	(252.4)	(0.9)	(253.2)	(252.8)	(252.5)
8	IFRS Ineligible Capitalized Costs	170.1	170.1	0.0	192.5	192.5	0.0	214.9	214.9	0.0	214.9	214.9	214.9
9	Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Total Base Operating Costs Adjustment**	170.1	170.1	0.0	192.5	192.5	0.0	214.9	214.9	0.0	214.9	214.9	214.9
12	**Net Operating Costs**	(52.1)	(49.3)	2.8	(29.5)	(59.9)	(30.4)	(36.7)	(37.6)	(0.9)	(38.3)	(37.9)	(37.6)
	Operating Costs by Resource												
13	Labour	38.2	39.2	1.1	38.8	19.8	(18.9)	25.3	25.2	(0.1)	24.4	25.1	25.9
14	Services - ABSU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Services - Other	24.9	27.9	3.0	24.9	13.9	(11.0)	13.1	12.6	(0.6)	13.1	12.8	12.6
16	Materials	0.2	0.2	0.0	0.2	0.1	(0.0)	0.1	0.1	0.0	0.1	0.1	0.1
17	Buildings & Equipment	0.3	0.3	(0.0)	0.3	0.1	(0.2)	0.2	0.2	0.0	0.2	0.2	0.2
18	Capitalized Overhead	(115.8)	(117.0)	(1.2)	(93.8)	(93.9)	(0.2)	(75.5)	(75.7)	(0.2)	(76.2)	(76.2)	(76.4)
19	External Recoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Total	(52.1)	(49.3)	2.8	(29.5)	(59.9)	(30.4)	(36.7)	(37.6)	(0.9)	(38.3)	(37.9)	(37.6)

BC Hydro
F23-F25 RRA

Schedule 6.0
Page 55

Taxes
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Gross Taxes**	L23	249.8	249.7	(0.1)	262.2	256.8	(5.4)	263.8	271.4	7.6	283.5	298.3	309.2
2	**Deferral Account Additions**	L22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Subtotal before Recoveries**		249.8	249.7	(0.1)	262.2	256.8	(5.4)	263.8	271.4	7.6	283.5	298.3	309.2
4	**Current Taxes**	L25	249.8	249.7	(0.1)	262.2	256.8	(5.4)	263.8	271.4	7.6	283.5	298.3	309.2
	Generation													
5	Grants in Lieu		26.9	26.6	(0.3)	27.9	27.4	(0.5)	28.2	28.1	(0.0)	28.9	30.0	30.9
6	School Taxes		17.4	17.7	0.3	18.3	17.7	(0.6)	17.9	18.0	0.1	18.4	18.3	18.0
7	Total		44.3	44.2	(0.0)	46.3	45.2	(1.1)	46.1	46.1	0.1	47.3	48.4	48.9
	Transmission													
8	Grants in Lieu		63.6	64.9	1.3	65.7	68.9	3.2	68.6	73.7	5.2	74.7	77.8	79.9
9	School Taxes		94.0	93.5	(0.5)	98.0	95.8	(2.2)	98.4	98.8	0.4	104.8	110.0	113.2
10	Total		157.6	158.4	0.8	163.7	164.7	1.0	167.0	172.6	5.6	179.5	187.9	193.2
	Distribution													
11	Grants in Lieu		8.5	8.6	0.0	8.9	8.9	0.0	9.2	8.7	(0.5)	8.6	9.1	9.3
12	School Taxes		20.6	20.0	(0.6)	24.0	20.7	(3.3)	22.5	21.6	(0.9)	25.4	29.9	34.2
13	Total		29.1	28.6	(0.6)	32.9	29.6	(3.3)	31.7	30.3	(1.5)	34.0	39.0	43.5
	Customer Care													
	Waneta 2/3													
14	Teck portion of property taxes	15.0 L29	0.6	0.9	0.3	0.6	0.8	0.2	0.8	0.8	(0.0)	0.8	0.8	0.9
15	Total		0.6	0.9	0.3	0.6	0.8	0.2	0.8	0.8	(0.0)	0.8	0.8	0.9
	Business Support													
16	Grants in Lieu		11.8	11.3	(0.6)	12.2	12.0	(0.2)	12.0	14.1	2.0	14.5	15.0	15.5
17	School Taxes		6.3	6.4	0.1	6.5	4.6	(1.9)	6.2	7.5	1.4	7.4	7.2	7.3
18	Total		18.2	17.7	(0.5)	18.7	16.6	(2.1)	18.2	21.6	3.4	21.9	22.3	22.8

BC Hydro
F23-F25 RRA

Schedule 6.0
Page 56

Taxes
($ million)

Line		Reference Column	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Total Before Regulatory Accounts													
18	Grants in Lieu	L5+L8+L11+L16	110.8	111.3	0.5	114.8	117.3	2.5	118.0	124.6	6.6	126.8	131.9	135.6
19	School Taxes	L6+L9+L12+L17	138.3	137.5	(0.8)	146.8	138.7	(8.0)	145.0	145.9	1.0	155.9	165.5	172.7
20	Waneta 2/3 Property Taxes	L14	0.6	0.9	0.3	0.6	0.8	0.2	0.8	0.8	(0.0)	0.8	0.8	0.9
21	Total		249.8	249.7	(0.1)	262.2	256.8	(5.4)	263.8	271.4	7.6	283.5	298.3	309.2
	Deferral Account Additions													
22	Transfers to NHDA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	**Total Gross Taxes**	L21 + L22	249.8	249.7	(0.1)	262.2	256.8	(5.4)	263.8	271.4	7.6	283.5	298.3	309.2
	Deferral Account Additions													
24	Transfers to NHDA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	**Total Current Taxes**	L23 + L24	249.8	249.7	(0.1)	262.2	256.8	(5.4)	263.8	271.4	7.6	283.5	298.3	309.2
	Allocation of Current Taxes													
26	Generation	Line 7	44.3	44.2	(0.0)	46.3	45.2	(1.1)	46.1	46.1	0.1	47.3	48.4	48.9
27	Transmission	Line 10	157.6	158.4	0.8	163.7	164.7	1.0	167.0	172.6	5.6	179.5	187.9	193.2
28	Distribution	Line 13	29.1	28.6	(0.6)	32.9	29.6	(3.3)	31.7	30.3	(1.5)	34.0	39.0	43.5
29	Customer Care	Line 15	0.6	0.9	0.3	0.6	0.8	0.2	0.8	0.8	(0.0)	0.8	0.8	0.9
30	Business Support	Line 18	18.2	17.7	(0.5)	18.7	16.6	(2.1)	18.2	21.6	3.4	21.9	22.3	22.8
31	Total		249.8	249.7	(0.1)	262.2	256.8	(5.4)	263.8	271.4	7.6	283.5	298.3	309.2

Depreciation and Amortization
($ million)

Line	Column	Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Gross Amortization**	L27	977.8	977.7	(0.0)	998.0	999.5	1.6	1,023.7	1,066.7	43.1	1,023.3	1,050.0	1,101.0
2	**Deferral Account Additions**	L25	0.0	(0.4)	(0.4)	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0
3	**Regulatory Account Additions**	L33	(0.2)	0.4	0.7	(0.5)	(0.8)	(0.3)	(0.5)	(29.8)	(29.3)	0.0	0.0	0.0
4	**Subtotal before Recoveries**		977.5	977.8	0.3	997.5	999.0	1.6	1,023.1	1,036.9	13.8	1,023.3	1,050.0	1,101.0
5	**Regulatory Account Recoveries**	L41	118.1	118.1	(0.0)	121.9	121.0	(0.9)	111.1	110.5	(0.6)	127.7	132.4	135.7
6	**Current Amortization**	L42	1,095.7	1,095.9	0.3	1,119.4	1,120.0	0.6	1,134.2	1,147.4	13.2	1,150.9	1,182.4	1,236.6
	Amortization of Capital Assets													
7	Generation	12.2 L8:L9	260.9	262.7	1.8	266.8	270.2	3.4	278.5	268.7	(9.8)	270.8	276.5	308.1
8	Transmission	12.3 L8:L9	228.4	229.2	0.8	230.8	230.5	(0.3)	233.8	259.3	25.5	250.8	255.7	264.0
9	Distribution	12.4 L8:L9	206.3	207.3	1.1	216.5	217.1	0.5	225.4	228.8	3.5	237.8	248.2	259.4
10	Business Support	12.1 L8:L9	189.9	186.6	(3.3)	190.4	187.9	(2.5)	191.7	216.3	24.6	200.3	207.7	205.4
11	Subtotal		885.4	885.8	0.4	904.5	905.6	1.2	929.4	973.2	43.8	959.7	988.1	1,037.0
	Electrification Plan													
12	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.6	1.7
13	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4
14	Subtotal		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.7	2.1
15	Total		885.4	885.8	0.4	904.5	905.6	1.2	929.4	973.2	43.8	959.9	988.9	1,039.0
	Dismantling Costs													
16	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	IPP Capital Leases													
21	IPP Capital Leases		88.9	88.9	0.0	90.1	90.1	0.0	90.6	90.6	(0.0)	61.4	59.5	60.3
22	Total		88.9	88.9	0.0	90.1	90.1	0.0	90.6	90.6	(0.0)	61.4	59.5	60.3
	Other Leases													
23	Amortization		3.4	2.6	(0.8)	3.4	4.1	0.6	3.7	3.0	(0.7)	2.0	1.7	1.7
	Deferral Account Additions													
24	Transfers to NHDA		0.0	0.4	0.4	0.0	(0.3)	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0
25	Total		0.0	0.4	0.4	0.0	(0.3)	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0
26	Less: Electric Vehicle Costs - Ineligible stations		(0.0)		0.0	(0.0)		0.0			0.0			
27	**Total Gross Amortization**		977.8	977.7	(0.0)	998.0	999.5	1.6	1,023.7	1,066.7	43.1	1,023.3	1,050.0	1,101.0
	Deferral Account Additions													
28	Transfers to NHDA		0.0	(0.4)	(0.4)	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0
	Transfer to Regulatory Account													
29	Amortization on Additions Variance	13.0 L50	0.0	0.4	0.4	0.0	(0.1)	(0.1)	0.0	(0.7)	(0.7)	0.0	0.0	0.0
30	Electric Vehicle Costs Additions - New Assets		0.0	0.0	0.0	(0.3)	(0.1)	0.1	(0.3)	(0.1)	0.2	0.0	0.0	0.0
31	Electric Vehicle Costs Additions - Existing Assets		(0.2)	0.0	0.2	(0.2)	(0.5)	(0.3)	(0.2)	(0.3)	(0.1)	0.0	0.0	0.0
32	Depreciation Study									(28.6)	(28.6)	0.0	0.0	0.0

Depreciation and Amortization
($ million)

Line		Reference Column	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
33	Transfer to Regulatory Account		(0.2)	0.4	0.7	(0.5)	(0.8)	(0.3)	(0.5)	(29.8)	(29.3)	0.0	0.0	0.0
	Regulatory Account Recoveries													
	DSM Amortization													
34	Generation - 90%	(2.2 L5:L6) * 90%	93.0	93.0	(0.0)	96.7	95.8	(0.8)	97.2	96.7	(0.5)	100.1	104.4	107.3
35	Transmission - 5%	(2.2 L5:L6) * 5%	5.2	5.2	(0.0)	5.4	5.3	(0.0)	5.4	5.4	(0.0)	5.6	5.8	6.0
36	Distribution - 5%	(2.2 L5:L6) * 5%	5.2	5.2	(0.0)	5.4	5.3	(0.0)	5.4	5.4	(0.0)	5.6	5.8	6.0
37	Total		103.3	103.3	(0.0)	107.4	106.5	(0.9)	108.0	107.4	(0.6)	111.2	116.0	119.3
38	**Pre-1996 CIAC Amortization**	2.2 L34	5.1	5.1	0.0	5.1	5.1	0.0	5.1	5.1	0.0	5.1	5.1	5.1
39	**Capital Additions Reg. Acct.**	2.2 L51	9.7	9.7	(0.0)	9.4	9.4	0.0	(2.1)	(2.1)	0.0	0.9	0.9	0.8
40	**Depreciation Study Reg. Acct.**	2.2 L177	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.4	10.4	10.4
41	**Total Recoveries**		118.1	118.1	(0.0)	121.9	121.0	(0.9)	111.1	110.5	(0.6)	127.7	132.4	135.7
42	**Total Current Amortization**		1,095.7	1,095.9	0.3	1,119.4	1,120.0	0.6	1,134.2	1,147.4	13.2	1,150.9	1,182.4	1,236.6
	Allocation of Current Amortization													
43	Generation	L7+L34	353.9	355.6	1.8	363.5	366.1	2.6	375.7	365.4	(10.4)	370.9	380.8	415.4
44	Transmission	L8+L35	233.5	234.4	0.8	236.1	235.8	(0.3)	239.2	264.7	25.5	256.5	262.1	271.7
45	Distribution	L9+L36+L38	216.5	217.6	1.1	227.0	227.5	0.5	235.9	239.3	3.4	248.5	259.3	270.9
46	Customer Care	L22	88.9	88.9	0.0	90.1	90.1	0.0	90.6	90.6	(0.0)	61.4	59.5	60.3
47	Business Support	L10+L23+L26+L29:L31+L39:L40	202.8	199.4	(3.4)	202.7	200.6	(2.1)	192.8	187.4	(5.3)	213.5	220.7	218.4
48	Total		1,095.7	1,095.9	0.3	1,119.4	1,120.0	0.6	1,134.2	1,147.4	13.2	1,150.9	1,182.4	1,236.6

Finance Charges
($ million)

Line	Column	Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	
1	**Gross Finance Charges**	L12	874.9	1,656.8	781.8	743.3	251.6	(491.8)	555.6	720.8	165.2	581.2	564.5	704.1
2	**Regulatory Account Additions**	L19	(121.8)	(805.3)	(683.5)	(21.3)	506.2	527.5	(19.2)	(46.5)	(27.3)	(23.5)	(23.4)	(22.0)
3	Less: Deferred IPP Capital Leases	L14	0.0	0.3	0.3	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0
4	Total Finance Charge Regulatory Acct. Additions	L32	0.0	(0.9)	(0.9)	0.0	61.7	61.7	0.0	(25.4)	(25.4)	0.0	0.0	0.0
5	Site C Project (IFRS 14 IDC impact)	L33	2.0	1.9	(0.1)	2.7	2.6	(0.1)	7.3	(2.3)	(9.6)	(10.1)	(11.1)	(7.5)
6	**Interest on Regulatory Accounts**	L36	(17.7)	(16.7)	1.0	(26.0)	(18.2)	7.8	(24.5)	(18.0)	6.5	(19.4)	(21.0)	(22.8)
7	**Subtotal before Recoveries**		737.5	836.1	98.6	698.7	804.1	105.3	519.3	628.6	109.3	528.1	508.9	651.7
8	**Regulatory Account Recoveries**	L42	(1.7)	(100.3)	(98.6)	(2.8)	(108.3)	(105.6)	(65.2)	(173.8)	(108.7)	28.7	28.8	28.8
9	**Current Finance Charges**	L43	735.8	735.8	(0.0)	696.0	695.7	(0.2)	454.1	454.8	0.6	556.9	537.7	680.5
10	**Before Electrification Plan**		874.9	1,656.8	781.8	743.3	251.6	(491.8)	555.6	720.8	165.2	580.3	561.7	697.4
11	**Electrification Plan**				0.0			0.0		0.0	0.0	0.9	2.8	6.7
12	**Total Gross Finance Charges**	L19 + L31	874.9	1,656.8	781.8	743.3	251.6	(491.8)	555.6	720.8	165.2	581.2	564.5	704.1
	Regulatory Account Additions													
13	FX Gains/Losses		(2.3)	5.3	7.5	(1.5)	(10.7)	(9.2)	(2.6)	0.4	3.0	0.6	0.7	(0.1)
14	Deferred IPP Capital Leases (Total Finance Charge Reg. Account Additions)		0.0	0.3	0.3	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0
15	Accretion - First Nations		17.6	17.6	0.0	18.0	18.0	0.0	18.3	18.3	0.0	18.4	18.6	18.8
16	Accretion - Environmental		5.5	4.8	(0.7)	4.8	2.9	(1.9)	3.4	5.2	1.7	4.6	4.1	3.4
17	Accretion - Arrow Water		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Debt Management		100.9	777.3	676.4	0.0	(516.6)	(516.6)	0.0	22.6	22.6	0.0	0.0	0.0
19	Total		121.8	805.3	683.5	21.3	(506.2)	(527.5)	19.2	46.5	27.3	23.5	23.4	22.0
20	**Adj. for Regulatory Account Additions**		753.1	851.5	98.3	722.0	757.8	35.8	536.4	674.3	137.9	557.6	541.1	682.1
	Total Before Regulatory Accounts													
21	Sinking Fund Income	Line 82	(7.8)	(9.1)	(1.2)	(7.7)	(8.9)	(1.2)	(3.2)	(3.9)	(0.8)	(4.0)	(4.1)	(4.2)
22	Long-Term Debt Costs	Line 98	825.3	824.9	(0.4)	851.5	821.5	(29.9)	772.5	784.2	11.7	828.9	861.6	916.7
23	Short-Term Debt Costs	Line 107	63.8	47.5	(16.2)	69.6	12.4	(57.2)	13.5	7.1	(6.5)	12.2	26.8	48.1
24	Interest Capitalized	Line 117	(181.5)	(175.5)	6.0	(242.6)	(225.9)	16.7	(287.4)	(261.7)	25.6	(317.5)	(375.0)	(303.5)
25	Other (Income) / Loss		39.2	50.5	11.3	45.1	46.2	1.0	47.0	46.6	(0.4)	47.4	46.5	45.4
26	IPP Capital Leases		48.4	48.4	0.0	46.1	46.1	0.0	43.5	43.5	(0.0)	41.4	40.1	38.7
27	Accretion - Non-Deferrable		1.3	1.3	(0.0)	1.3	1.1	(0.2)	1.0	1.6	0.6	1.6	1.5	1.5
28	Non-Current PEB		(36.5)	62.1	98.6	(42.2)	64.0	106.2	(52.0)	56.0	108.0	(53.3)	(57.3)	(61.6)
29	NTL Supplemental Interest Income		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Other Leases		1.0	1.3	0.2	1.0	1.4	0.4	1.5	1.0	(0.4)	1.0	1.0	0.9
31	Total		753.1	851.5	98.3	722.0	757.8	35.8	536.4	674.3	137.9	557.6	541.1	682.1
32	Total Finance Charge Regulatory Acct. Additions	L27-L14-L31-L33-L36-L37-L38	0.0	(0.9)	(0.9)	0.0	61.7	61.7	0.0	(25.4)	(25.4)	0.0	0.0	0.0
33	Site C Project (IFRS 14 IDC impact)		2.0	1.9	(0.1)	2.7	2.6	(0.1)	7.3	(2.3)	(9.6)	(10.1)	(11.1)	(7.5)
	Interest on Regulatory Accounts													
34	Interest on Deferral Accounts	2.1 L55	15.4	15.9	0.5	4.0	9.0	5.0	0.7	6.6	6.0	5.0	2.8	1.8
35	Interest on Other Reg Accounts	2.2 L209	(33.1)	(32.6)	0.5	(30.0)	(27.2)	2.8	(25.1)	(24.6)	0.5	(24.4)	(23.8)	(24.6)
36	Total		(17.7)	(16.7)	1.0	(26.0)	(18.2)	7.8	(24.5)	(18.0)	6.5	(19.4)	(21.0)	(22.8)

BC Hydro
F23-F25 RRA

Schedule 8.0
Page 60

Finance Charges
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	
	Regulatory Account Recoveries													
37	Amort. of FX Gains/Losses		0.5	0.5	0.0	(0.5)	0.1	0.6	(0.1)	(0.8)	(0.7)	0.6	0.7	0.7
38	Non-Current Pension		0.0	(98.6)	(98.6)	0.0	(106.2)	(106.2)	0.0	(108.0)	(108.0)	0.0	0.0	0.0
39	Total Finance Charges		10.1	10.1	0.0	10.1	10.1	0.0	(74.1)	(74.1)	0.0	12.9	12.9	12.9
40	Debt Management		(12.4)	(12.4)	0.0	(12.4)	(12.4)	(0.0)	9.1	9.1	0.0	15.2	15.2	15.2
41	F2017 Correction (RRA Adjustment)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	Total		(1.7)	(100.3)	(98.6)	(2.8)	(108.3)	(105.6)	(65.2)	(173.8)	(108.7)	28.7	28.8	28.8
43	**Total Current Finance Charges**	L14+L31+L32+ L33+L36+L42	735.8	735.8	(0.0)	696.0	695.7	(0.2)	454.1	454.8	0.6	556.9	537.7	680.5
	Portion of Rate Base													
44	Generation	10.0 L28	46.0%	46.2%	0.2%	45.9%	46.1%	0.1%	45.7%	45.5%	(0.2%)	45.2%	44.8%	57.0%
45	Transmission	10.0 L29	33.2%	33.0%	-0.1%	32.7%	32.8%	0.0%	32.7%	32.8%	0.1%	32.6%	32.5%	25.4%
46	Distribution	10.0 L30	20.8%	20.8%	-0.1%	21.4%	21.2%	(0.2%)	21.6%	21.7%	0.1%	22.2%	22.7%	17.6%
47	Total		100.0%	100.0%	0.0%	100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%	100.0%
	Allocation of Current Finance Charges													
48	Generation		338.4	339.9	1.5	319.6	320.5	0.9	207.7	206.9	(0.8)	251.6	241.0	387.7
49	Transmission		243.9	243.0	(0.9)	227.6	227.9	0.2	148.3	149.1	0.8	181.5	174.9	172.9
50	Distribution		153.4	152.8	(0.6)	148.8	147.4	(1.4)	98.1	98.8	0.7	123.8	121.9	120.0
51	Total		735.8	735.8	(0.0)	696.0	695.7	(0.2)	454.1	454.8	0.6	556.9	537.7	680.5
	Net Debt													
52	Sinking Funds	Line 83	(201.2)	(217.3)	(16.1)	(205.9)	(202.7)	3.2	(200.1)	(207.7)	(7.6)	(213.2)	(219.2)	(223.1)
53	Temporary Investments		(10.0)	(115.3)	(105.3)	(10.0)	(37.0)	(27.0)	(10.0)	(10.0)	0.0	(10.0)	(10.0)	(10.0)
54	Long-Term Debt	Line 93	20,777.8	20,942.6	164.8	21,956.8	22,176.5	219.7	22,949.7	23,187.1	237.3	25,473.6	26,460.5	28,726.5
55	Short-Term Debt	Line 102	2,950.3	2,743.5	(206.8)	3,139.9	2,803.3	(336.5)	3,129.5	4,206.2	1,076.8	4,265.6	4,664.2	3,217.8
56	Capital Lease Obligation						1,419.7	1,419.7		1,352.5	1,352.5	1,314.9	1,276.7	1,235.3
57	Subtotal		23,516.9	23,353.4	(163.4)	24,880.8	26,159.9	1,279.1	25,869.1	28,528.1	2,659.0	30,830.8	32,172.1	32,946.4
58	WACD Adjustment		180.2	291.1	110.9	188.0	210.2	22.3	197.4	191.9	(5.5)	199.3	207.3	213.3
59	End of Year		23,697.0	23,644.5	(52.5)	25,068.8	26,370.2	1,301.4	26,066.5	28,720.0	2,653.5	31,030.1	32,379.4	33,159.7
60	Mid-Year Balance		23,014.6	22,988.3	(26.3)	24,382.9	25,753.0	1,370.1	25,740.8	27,545.1	1,804.3	29,875.0	31,704.7	32,769.6
	Weighted Average Cost of Debt (WACD) Rate													
61	Total Gross Finance Charges	Line 12	874.9	1,656.8	781.8	743.3	251.6	(491.8)	555.6	720.8	165.2	581.2	564.5	704.1
62	WACD Adjustment		1.8	(796.1)	(797.9)	165.4	619.1	453.8	239.5	124.0	(115.5)	317.4	380.2	315.6
63	Finance Charges for WACD		876.7	860.6	(16.1)	908.7	870.7	(38.0)	795.1	844.8	49.7	898.6	944.7	1,019.6
64	Weighted Average Cost of Debt (WACD) Rate		3.81%	3.74%	(0.07%)	3.73%	3.38%	(0.35%)	3.09%	3.07%	(0.02%)	3.01%	2.98%	3.11%

Finance Charges
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
Column			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	
	Increase in Cash													
65	Net Income	9.0 L33	712.0	704.9	(7.1)	712.0	687.5	(24.5)	712.0	704.4	(7.6)	712.0	712.0	712.0
66	Dividend (One Year Lag)	9.0 L4	(59.0)	(59.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
67	Amortization	7.0 L27	977.8	977.7	(0.0)	998.0	999.5	1.6	1,023.7	1,066.7	43.1	1,023.3	1,050.0	1,101.0
68	Deferral Account Additions	2.1 L54	3.1	52.2	49.1	3.5	393.3	389.8	15.5	(7.1)	(22.6)	2.8	3.7	2.4
69	Deferral Account Recoveries	2.1 L56	(403.9)	(403.9)	0.1	(226.9)	(451.4)	(224.6)	0.0	0.0	0.0	(106.6)	(55.3)	(28.9)
70	Regulatory Account Additions	2.2 L208	(267.7)	(984.2)	(716.5)	(133.1)	381.2	514.3	(114.7)	(194.4)	(79.7)	(173.0)	(180.9)	(178.1)
71	Regulatory Account Recoveries	2.2 L210	386.7	287.7	(99.1)	384.6	266.9	(117.7)	335.7	226.4	(109.3)	362.4	372.4	338.1
72	First Nations Provisions	2.2 L17	0.0	0.9	0.9	0.0	1.2	1.2	0.0	(4.5)	(4.5)	0.0	0.0	0.0
73	Environmental Provisions	2.2 L78	0.0	51.2	51.2	0.0	51.2	51.2	0.0	(0.8)	(0.8)	0.0	0.0	0.0
74	Capital Expenditures	13.0 L17	(2,988.3)	(3,071.4)	(83.1)	(3,104.2)	(3,197.5)	(93.3)	(2,959.0)	(4,359.9)	(1,400.9)	(4,306.2)	(3,425.8)	(2,862.1)
75	Contributions in Aid	11.0 L36	157.8	178.8	21.0	148.5	195.7	47.2	214.2	158.7	(55.5)	188.1	186.1	177.4
76	Change in Sinking Funds	Line 81	3.9	(11.0)	(14.9)	3.1	23.6	20.5	5.7	(1.2)	(6.9)	(1.4)	(1.8)	0.3
77	Change in Working Cap & Other		131.4	971.9	840.5	(153.9)	(645.0)	(491.0)	(332.4)	(1.9)	330.5	(47.1)	(45.8)	(81.7)
78	F17-F19 RRA Compliance Filing Adjustment		0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
79	Total		(1,346.3)	(1,304.2)	42.1	(1,368.6)	(1,293.8)	74.8	(1,099.4)	(2,413.5)	(1,314.1)	(2,345.8)	(1,385.5)	(819.6)
	Sinking Funds													
80	Beginning of Year		197.3	197.3	0.0	201.2	217.3	16.1	202.7	202.7	0.0	207.7	213.2	219.2
81	Change in Sinking Funds		(3.9)	11.0	14.9	(3.1)	(23.6)	(20.5)	(5.7)	1.2	6.9	1.4	1.8	(0.3)
82	Sinking Fund Income		7.8	9.1	1.2	7.7	8.9	1.2	3.2	3.9	0.8	4.0	4.1	4.2
83	End of Year		201.2	217.3	16.1	205.9	202.7	(3.2)	200.1	207.7	7.6	213.2	219.2	223.1
84	Mid-Year Balance		199.2	207.3	8.1	203.5	210.0	6.5	201.4	205.2	3.8	210.5	216.2	221.2
	Long-Term Debt													
85	Beginning of Year		19,437.1	19,437.1	0.0	20,777.8	20,942.6	164.8	22,176.5	22,176.5	0.0	23,187.1	25,473.6	26,460.5
86	Bonds Retired		(175.0)	(175.0)	0.0	(1,099.8)	(1,099.8)	0.0	(526.3)	(526.3)	0.0	(500.0)	(200.0)	(10.0)
87	Bonds Issued		0.0	1,500.0	1,500.0	0.0	2,200.0	2,200.0	0.0	675.0	675.0	0.0	0.0	0.0
88	Bonds Planned Issues		1,500.0	0.0	(1,500.0)	2,300.0	0.0	(2,300.0)	1,350.0	900.0	(450.0)	2,800.0	1,200.0	2,300.0
89	Revaluation of Foreign $ Debt		(18.4)	78.8	97.2	(16.2)	(152.3)	(136.1)	(29.1)	5.0	34.1	7.1	8.8	(1.5)
90	Revaluation to Fair Value		0.0	(2.0)	(2.0)	0.0	(0.9)	(0.9)	0.0	0.0	0.0	0.0	0.0	0.0
91	Premiums/(Discounts) on Issues		40.5	108.1	67.6	0.0	302.2	302.2	0.0	(23.5)	(23.5)	0.0	0.0	0.0
92	Amortization of Issue Costs		(6.4)	(4.4)	2.0	(5.0)	(15.2)	(10.2)	(21.3)	(19.6)	1.8	(20.6)	(21.9)	(22.5)
93	End of Year		20,777.8	20,942.6	164.8	21,956.8	22,176.5	219.7	22,949.7	23,187.1	237.3	25,473.6	26,460.5	28,726.5
94	Mid-Year Balance		20,107.4	20,189.8	82.4	21,367.3	21,559.5	192.2	22,563.1	22,681.8	118.7	24,330.3	25,967.0	27,593.5
95	Interest Rate - Planned Issues		3.46%			3.76%			1.91%			2.38%	2.66%	2.91%
96	Debt Costs - Excluding Planned		799.4	824.9	25.6	756.3	821.5	65.2	759.6	784.2	24.6	795.6	779.0	784.7
97	Debt Costs - Planned Issues		25.9	0.0	(25.9)	95.2	0.0	(95.2)	12.9	0.0	(12.9)	33.3	82.6	132.0
98	Total Long-Term Debt Costs		825.3	824.9	(0.4)	851.5	821.5	(29.9)	772.5	784.2	11.7	828.9	861.6	916.7
	Short-Term Debt													
99	Beginning of Year		2,944.7	2,944.7	0.0	2,950.3	2,743.5	(206.8)	2,803.3	2,803.3	0.0	4,206.2	4,265.6	4,664.2
100	Increase in Cash Requirement	Line 79	1,346.3	1,304.2	(42.1)	1,368.6	1,293.8	(74.8)	1,099.4	2,413.5	1,314.1	2,345.8	1,385.5	819.6
101	Change in Long-Term Debt	L85 - L93	(1,340.7)	(1,505.5)	(164.8)	(1,179.0)	(1,233.9)	(54.9)	(773.2)	(1,010.6)	(237.3)	(2,286.5)	(986.9)	(2,266.0)
102	End of Year		2,950.3	2,743.5	(206.8)	3,139.9	2,803.3	(336.5)	3,129.5	4,206.2	1,076.8	4,265.6	4,664.2	3,217.8
103	Mid-Year Balance		2,947.5	2,844.1	(103.4)	3,045.1	2,773.4	(271.7)	3,074.2	3,504.8	430.6	4,235.9	4,464.9	3,941.0
104	Interest Rate		2.35%			2.69%			0.39%			0.31%	0.61%	1.30%
105	Debt Costs - Interest		69.3	47.5	(21.8)	81.9	12.4	(69.5)	12.0	7.1	(4.9)	13.1	27.2	51.2
106	Debt Costs - Other		(5.6)	0.0	5.6	(12.3)	0.0	12.3	1.5	0.0	(1.5)	(1.0)	(0.4)	(3.1)
107	Total Short-Term Debt Costs		63.8	47.5	(16.2)	69.6	12.4	(57.2)	13.5	7.1	(6.5)	12.2	26.8	48.1

BC Hydro
F23-F25 RRA

Schedule 8.0
Page 62

Finance Charges
($ million)

			F2020			F2021			F2022			F2023	F2024	F2025
		Reference	Decision	Actual	Diff	Decision	Actual	Diff	Decision	Forecast	Diff	Plan	Plan	Plan
Line	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	
	Interest During Construction (IDC) Rate													
108	Finance Charges for WACD	Line 63	876.7	860.6	(16.1)	908.7	870.7	(38.0)	795.1	844.8	49.7	898.6	944.7	1,019.6
109	Amortization of Debt Management Reg. Acct.	Line 40	12.4	12.4	0.0	12.4	12.4	0.0	(9.1)	(9.1)	0.0	(15.2)	(15.2)	(15.2)
110	Finance Charges for IDC		889.1	873.0	(16.1)	921.1	883.1	(38.0)	786.1	835.7	49.7	883.4	929.5	1,004.4
111	Net Debt Mid-Year Balance	Line 60	23,014.6	22,988.3	(26.3)	24,382.9	25,753.0	1,370.1	25,740.8	27,545.1	1,804.3	29,875.0	31,704.7	32,769.6
112	Interest During Construction (IDC) Rate		3.86%	3.80%	(0.07%)	3.78%	3.43%	(0.35%)	3.05%	3.03%	(0.02%)	2.96%	2.93%	3.07%
	Interest Capitalized													
113	Unfinished Construction	13.0 L35	**5,347.0**	5,463.4	116.3	**6,958.5**	7,250.987	292.5	**8,688.0**	9,462.8	774.8	12,202.7	14,558.6	9,163.6
114	Less Not Subject to IDC		**(647.5)**	**(841.9)**	(194.5)	**(535.5)**	**(663.1)**	(127.5)	**721.7**	**(837.0)**	(1,558.6)	**(1,466.3)**	**(1,768.0)**	**737.1**
115	Unfinished Subject to IDC		4,699.6	4,621.4	(78.1)	6,423.0	6,587.9	164.9	9,409.6	8,625.8	(783.8)	10,736.4	12,790.5	9,900.8
116	Interest During Construction (IDC) Rate	Line 112	3.86%	3.80%	(0.07%)	3.78%	3.43%	(0.35%)	3.05%	3.03%	(0.02%)	2.96%	2.93%	3.07%
117	Interest Capitalized		181.5	175.5	(6.0)	242.6	225.9	(16.7)	287.4	261.7	(25.6)	317.5	375.0	303.5

BC Hydro
F23-F25 RRA

Schedule 9.0
Page 63

Return on Equity
($ million)

Line		Reference	F2020			F2021			F2022			F2023	F2024	F2025
			Decision	Actual	Diff	Decision	Actual	Diff	Decision	Forecast	Diff	Plan	Plan	Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Shareholder's Equity													
1	Retained Earnings - Beginning of Year		4,995.0	4,995.0	0.0	5,706.2	5,698.6	(7.6)	6,386.1	6,386.1	0.0	7,090.5	7,802.5	8,514.5
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Gross Return on Equity	Line 33	712.0	704.9	(7.1)	712.0	687.5	(24.5)	712.0	704.4	(7.6)	712.0	712.0	712.0
4	Dividend to Province	Line 15	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Other Leases		(0.8)	(1.3)	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Retained Earnings - End of Year		5,706.2	5,698.6	(7.6)	6,418.2	6,386.1	(32.1)	7,098.1	7,090.5	(7.6)	7,802.5	8,514.5	9,226.5
7	Accum Other Comp Income		23.2	273.5	250.3	(46.8)	137.7	184.6	(43.7)	87.2	130.9	(18.6)	(18.6)	(18.6)
8	OCI Deferred (Pension)		(70.0)	(317.2)	(247.2)	0.0	(156.3)	(156.3)	0.0	(105.8)	(105.8)	0.0	0.0	0.0
9	Total Shareholder's Equity		5,659.3	5,654.8	(4.5)	6,371.3	6,367.5	(3.8)	7,054.4	7,071.9	17.6	7,783.9	8,495.9	9,207.9
	Dividend to Province													
10	Net Income	Line 3	712.0			712.0			712.0	704.4		712.0	712.0	712.0
11	Distributable Surplus		712.0			712.0			712.0	704.4		712.0	712.0	712.0
12	Maximum Dividend Percentage													
13	Maximum Dividend Amount													
14	Minimum Equity Percentage													
15	Dividend to Province		0.0											
	Capitalization													
16	Net Debt	8.0 L57	23,516.9	23,353.4	(163.4)	24,880.8	26,159.9	1,279.1	25,869.1	28,528.1	2,659.0	30,830.8	32,172.1	32,946.4
17	Shareholder's Equity	Line 9	5,659.3	5,654.8	(4.5)	6,371.3	6,367.5	(3.8)	7,054.4	7,071.9	17.6	7,783.9	8,495.9	9,207.9
18	Total		29,176.2	29,008.3	(167.9)	31,252.1	32,527.5	1,275.3	32,923.5	35,600.0	2,676.6	38,614.7	40,668.1	42,154.4
	Capital Structure													
19	Net Debt		80.6%	80.5%	(0.1%)	79.6%	80.4%	0.8%	78.6%	80.1%	1.6%	79.8%	79.1%	78.2%
20	Equity		19.4%	19.5%	0.1%	20.4%	19.6%	(0.8%)	21.4%	19.9%	(1.6%)	20.2%	20.9%	21.8%
21	Total		100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%	100.0%
	Deemed Equity													
22	Rate Base	10.0 L26	22,928.8	22,750.5	(178.3)	23,335.6	23,098.9	(236.7)	23,398.1	23,659.3	261.2	24,041.6	24,433.0	38,813.6
23	Pre-1996 Customer Contns	2.2 L35	(78.2)	(78.2)	0.0	(73.1)	(73.1)	0.0	(67.9)	(67.9)	0.0	(62.8)	(57.7)	(52.5)
24	Powerex & Powertech Assets		65.5	90.4	24.9	67.3	97.8	30.6	93.1	97.7	4.7	96.5	95.3	93.5
25	Allowance for Working Capital		250.0	250.0	0.0	250.0	250.0	0.0	250.0	250.0	0.0	250.0	250.0	250.0
26	Total		23,166.1	23,012.7	(153.4)	23,579.8	23,373.6	(206.1)	23,673.3	23,939.1	265.9	24,325.4	24,720.6	39,104.5
27	Deemed Equity Percentage		30.0%	30.0%	0.0%	30.0%	30.0%	0.0%	30.0%	30.0%	0.0%	30.0%	30.0%	30.0%
28	Year-End Deemed Equity		6,949.8	6,903.8	(46.0)	7,073.9	7,012.1	(61.8)	7,102.0	7,181.7	79.8	7,297.6	7,416.2	11,731.4
29	Mid-Year Deemed Equity		6,894.2	6,871.2	(23.0)	7,011.9	6,957.9	(53.9)	7,057.0	7,096.9	39.9	7,239.7	7,356.9	9,573.8
30	Achieved ROE			10.26%			9.88%			9.93%				
31	Allowed ROE / Derived ROE (F18-F21)		10.33%			10.15%			10.09%			9.83%	9.68%	7.44%
32	Return on Equity		712.0	704.9	(7.1)	712.0	687.5	(24.5)	712.0	704.4	(7.6)	712.0	712.0	712.0
33	Gross Return on Equity		712.0	704.9	(7.1)	712.0	687.5	(24.5)	712.0	704.4	(7.6)	712.0	712.0	712.0

BC Hydro
F23-F25 RRA

Schedule 9.0
Page 64

Return on Equity
($ million)

			F2020			F2021			F2022			F2023	F2024	F2025
		Reference	Decision	Actual	Diff	Decision	Actual	Diff	Decision	Forecast	Diff	Plan	Plan	Plan
Line	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
34	**Current Return on Equity**		712.0	704.9	(7.1)	712.0	687.5	(24.5)	712.0	704.4	(7.6)	712.0	712.0	712.0
	Portion of Rate Base													
35	Generation	10.0 L28	46.0%	46.2%	0.2%	45.9%	46.1%	0.1%	45.7%	45.5%	(0.2%)	45.2%	44.8%	57.0%
36	Transmission	10.0 L29	33.2%	33.0%	(0.1%)	32.7%	32.8%	0.0%	32.7%	32.8%	0.1%	32.6%	32.5%	25.4%
37	Distribution	10.0 L30	20.8%	20.8%	(0.1%)	21.4%	21.2%	(0.2%)	21.6%	21.7%	0.1%	22.2%	22.7%	17.6%
38	Total		100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%	100.0%
	Allocation of ROE													
39	Generation	L34 x L35	327.5	325.6	(1.9)	326.9	316.7	(10.2)	325.7	320.5	(5.2)	321.7	319.1	405.6
40	Transmission	L34 x L36	236.1	232.8	(3.2)	232.9	225.2	(7.7)	232.5	231.0	(1.5)	232.1	231.5	180.9
41	Distribution	L34 x L37	148.4	146.4	(2.0)	152.2	145.6	(6.6)	153.8	153.0	(0.8)	158.3	161.4	125.5
42	Total		712.0	704.9	(7.1)	712.0	687.5	(24.5)	712.0	704.4	(7.6)	712.0	712.0	712.0

BC Hydro
F23-F25 RRA

Schedule 10.0
Page 65

Rate Base
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Generation													
1	Net Assets in Service	12.2 L13	8,953.8	8,994.9	41.1	9,168.9	9,046.4	(122.5)	9,035.9	9,166.7	130.8	9,335.0	9,277.6	23,192.3
2	Net Contributions	11.0 L10	(2.3)	(2.3)	0.0	(2.1)	(2.0)	0.0	(1.8)	(1.8)	0.0	(1.5)	(1.3)	(1.1)
3	90% of Net DSM	2.2 L7 x 90%	828.3	815.9	(12.4)	820.5	793.1	(27.4)	783.9	781.9	(2.0)	797.5	814.3	830.9
4	Total		9,779.8	9,808.5	28.7	9,987.4	9,837.5	(149.9)	9,818.0	9,946.8	128.8	10,131.0	10,090.6	24,022.2
5	Mid-Year		9,738.3	9,752.6	14.4	9,883.6	9,823.0	(60.6)	9,902.7	9,892.1	(10.5)	10,038.9	10,110.8	17,056.4
	Transmission													
6	Net Assets in Service	12.3 L13	7,301.7	7,207.2	(94.6)	7,293.2	7,271.8	(21.4)	7,471.0	7,496.3	25.4	7,511.7	7,715.0	8,065.8
7	Net Contributions	11.0 L22	(303.7)	(301.4)	2.3	(303.5)	(299.4)	4.2	(302.4)	(296.3)	6.1	(313.5)	(328.2)	(331.9)
8	5% of Net DSM	2.2 L7 x 5%	46.0	45.3	(0.7)	45.6	44.1	(1.5)	43.5	43.4	(0.1)	44.3	45.2	46.2
9	Total		7,044.0	6,951.1	(92.9)	7,035.3	7,016.5	(18.8)	7,212.1	7,243.5	31.4	7,242.5	7,432.0	7,780.0
10	Mid-Year		7,019.2	6,972.8	(46.5)	7,039.6	6,983.8	(55.9)	7,123.7	7,130.0	6.3	7,243.0	7,337.3	7,606.0
	Distribution													
11	Net Assets in Service	12.4 L13	5,913.5	5,880.0	(33.5)	6,208.2	6,171.5	(36.7)	6,417.1	6,538.1	121.0	6,815.8	7,099.1	7,351.1
12	Less: Electric Vehicle Costs Assets		(0.2)			(2.4)								
13	Net Contributions	11.0 L33	(1,458.9)	(1,481.5)	(22.6)	(1,549.8)	(1,624.7)	(74.8)	(1,778.2)	(1,727.5)	50.8	(1,835.4)	(1,940.8)	(2,044.6)
14	5% of Net DSM	2.2 L7 x 5%	46.0	45.3	(0.7)	45.6	44.1	(1.5)	43.5	43.4	(0.1)	44.3	45.2	46.2
15	Total		4,500.4	4,443.8	(56.8)	4,701.6	4,590.9	(113.1)	4,682.4	4,854.1	171.7	5,024.8	5,203.5	5,352.7
16	Mid-Year		4,413.2	4,384.9	(28.3)	4,601.0	4,517.3	(83.6)	4,692.0	4,722.5	30.5	4,939.4	5,114.1	5,278.1
	Business Support													
17	Net Assets in Service	12.1 L12	1,604.8	1,547.1	(57.7)	1,611.3	1,654.0	42.6	1,685.6	1,614.9	(70.7)	1,643.4	1,706.8	1,658.6
18	Less: Electric Vehicle Costs Assets		(0.2)			(0.0)								
19	Net Contributions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Total		1,604.6	1,547.1	(57.5)	1,611.3	1,654.0	42.6	1,685.6	1,614.9	(70.7)	1,643.4	1,706.8	1,658.6
21	Mid-Year		1,576.0	1,547.2	(28.8)	1,608.0	1,600.5	(7.5)	1,648.5	1,634.4	(14.0)	1,629.1	1,675.1	1,682.7
	Total													
22	Net Assets in Service	12.0 L14	23,773.9	23,629.1	(144.8)	24,281.7	24,143.7	(138.0)	24,609.6	24,816.0	206.4	25,305.9	25,798.5	40,267.9
23	Less: Electric Vehicle Costs Assets		(0.5)	0.0	0.5	(2.4)	0.0	2.4	0.0	0.0	0.0	0.0	0.0	0.0
24	Net Contributions	11.0 L46	(1,764.9)	(1,785.3)	(20.3)	(1,855.4)	(1,926.1)	(70.6)	(2,082.4)	(2,025.5)	56.9	(2,150.4)	(2,270.3)	(2,377.6)
25	Net DSM	2.2 L7	920.3	906.6	(13.7)	911.7	881.2	(30.4)	871.0	868.8	(2.2)	886.1	904.8	923.2
26	Total		22,928.8	22,750.5	(178.3)	23,335.6	23,098.9	(236.7)	23,398.1	23,659.3	261.2	24,041.6	24,433.0	38,813.6
27	Mid-Year		22,746.7	22,657.5	(89.2)	23,132.2	22,924.7	(207.5)	23,366.9	23,379.1	12.2	23,850.5	24,237.3	31,623.3
	Portion of Rate Base													
28	Generation		46.0%	46.2%	0.2%	45.9%	46.1%	0.1%	45.7%	45.5%	(0.2%)	45.2%	44.8%	57.0%
29	Transmission		33.2%	33.0%	(0.1%)	32.7%	32.8%	0.0%	32.7%	32.8%	0.1%	32.6%	32.5%	25.4%
30	Distribution		20.8%	20.8%	(0.1%)	21.4%	21.2%	(0.2%)	21.6%	21.7%	0.1%	22.2%	22.7%	17.6%
31	Total		100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%	100.0%

BC Hydro
F23-F25 RRA

Contributions
($ million)

Line		Reference Column	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Contributions in Aid - Generation													
1	Gross Contns - Beginning of Year		9.4	9.4	0.0	9.4	9.4	(0.0)	8.7	8.7	0.0	8.7	8.7	8.7
2	IFRS Opening Balance Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Additions		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Retirements & Transfers		(0.0)	0.0	0.0	(0.0)	(0.6)	(0.6)	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)
5	Gross Contns - End of Year		9.4	9.4	(0.0)	9.4	8.7	(0.6)	8.7	8.7	0.0	8.7	8.7	8.7
6	Accum Amort - Beginning of Year		6.8	6.8	0.0	7.0	7.1	0.0	6.7	6.7	0.0	6.9	7.2	7.4
7	Amortization		0.3	0.3	0.0	0.2	0.3	0.0	0.2	0.2	0.0	0.2	0.2	0.2
8	Retirements & Transfers		0.0	0.0	0.0	0.0	(0.6)	(0.6)	0.0	0.0	0.0	0.0	0.0	0.0
9	Accum Amort - End of Year		7.0	7.1	0.0	7.3	6.7	(0.6)	6.9	6.9	0.0	7.2	7.4	7.7
10	Net Contributions - End of Year		2.3	2.3	(0.0)	2.1	2.0	(0.0)	1.8	1.8	(0.0)	1.5	1.3	1.1
	Contributions in Aid - Transmission													
11	Gross Contns - Beginning of Year		415.3	415.3	0.0	438.9	427.9	(11.0)	431.1	431.1	0.0	439.9	469.4	496.0
12	IFRS Opening Balance Adjustment		0.0	(0.7)	(0.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Additions		23.7	17.9	(5.8)	14.8	9.0	(5.8)	14.0	8.9	(5.1)	29.7	26.6	16.2
14	Retirements & Transfers		(0.1)	(4.6)	(4.4)	(0.2)	(5.8)	(5.7)	(0.1)	(0.1)	0.0	(0.1)	(0.1)	(0.1)
15	Gross Contns - End of Year		438.9	427.9	(11.0)	453.5	431.1	(22.4)	445.0	439.9	(5.1)	469.4	496.0	512.1
16	Accum Amort - Beginning of Year		120.7	120.7	0.0	135.1	126.5	(8.7)	131.7	131.7	0.0	143.6	155.9	167.8
17	IFRS Opening Balance Adjustment		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Amortization		14.4	14.8	0.3	14.8	14.6	(0.2)	10.9	11.9	1.0	12.3	11.8	12.4
19	Retirements & Transfers		0.0	(4.7)	(4.7)	0.0	(5.1)	(5.1)	0.0	0.0	0.0	0.0	0.0	0.0
20	IFRS amortization reclassification		0.0	(4.3)	(4.3)	0.0	(4.3)	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0
21	Accum Amort - End of Year		135.1	126.5	(8.7)	150.0	131.7	(18.3)	142.6	143.6	1.0	155.9	167.8	180.1
22	Net Contributions - End of Year		303.7	301.4	(2.3)	303.5	299.4	(4.2)	302.4	296.3	(6.1)	313.5	328.2	331.9
	Contributions in Aid - Distribution													
23	Gross Contns - Beginning of Year		2,114.4	2,114.4	0.0	2,244.2	2,263.5	19.3	2,441.7	2,441.7	0.0	2,586.9	2,740.6	2,895.1
24	IFRS Opening Balance Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	Additions		134.0	160.9	26.9	133.7	186.7	53.0	200.2	149.8	(50.4)	158.4	159.4	161.2
26	Retirements & Transfers		(4.2)	(11.8)	(7.6)	(4.4)	(8.5)	(4.1)	(4.7)	(4.5)	0.2	(4.8)	(4.9)	(5.0)
27	Gross Contns - End of Year		2,244.2	2,263.5	19.3	2,373.5	2,441.7	68.1	2,637.2	2,586.9	(50.2)	2,740.6	2,895.1	3,051.3
28	Accum Amort - Beginning of Year		749.8	749.8	0.0	785.3	782.0	(3.4)	817.0	817.0	0.0	859.5	905.2	954.3
29	Amortization		40.6	40.4	(0.2)	43.5	44.1	0.6	47.0	47.6	0.6	50.8	54.2	57.6
30	Amortization of Pre-1996 CIAC	2.2 L34	(5.1)	(5.1)	0.0	(5.1)	(5.1)	0.0	(5.1)	(5.1)	0.0	(5.1)	(5.1)	(5.1)
31	Retirements & Transfers		0.0	(3.1)	(3.1)	0.0	(4.0)	(4.0)	0.0	0.0	0.0	0.0	0.0	0.0
32	Accum Amort - End of Year		785.3	782.0	(3.4)	823.7	817.0	(6.7)	858.9	859.5	0.6	905.2	954.3	1,006.8
33	Net Contributions - End of Year		1,458.9	1,481.5	22.6	1,549.8	1,624.7	74.8	1,778.2	1,727.5	(50.8)	1,835.4	1,940.8	2,044.6

Contributions
($ million)

Line		Reference Column	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Contributions in Aid - Total													
34	Gross Contns - Beginning of Year		2,539.0	2,539.0	0.0	2,692.5	2,700.8	8.3	2,881.5	2,881.5	0.0	3,035.6	3,218.7	3,399.8
35	IFRS Opening Balance Adjustment		0.0	(0.7)	(0.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Additions		157.8	178.8	21.0	148.5	195.7	47.2	214.2	158.7	(55.5)	188.1	186.1	177.4
37	Retirements & Transfers		(4.3)	(16.4)	(12.0)	(4.5)	(15.0)	(10.4)	(4.8)	(4.6)	0.2	(4.9)	(5.0)	(5.1)
38	Gross Contns - End of Year		2,692.5	2,700.8	8.3	2,836.4	2,881.5	45.1	3,090.8	3,035.6	(55.3)	3,218.7	3,399.8	3,572.1
39	Accum Amort - Beginning of Year		877.3	877.3	0.0	927.5	915.5	(12.0)	955.4	955.4	0.0	1,010.1	1,068.3	1,129.5
40	IFRS Opening Balance Adjustment		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Amortization		55.3	55.5	0.1	58.6	59.0	0.4	58.2	59.8	1.6	63.4	66.3	70.2
42	Amortization of Pre-96 CIAC		(5.1)	(5.1)	0.0	(5.1)	(5.1)	0.0	(5.1)	(5.1)	0.0	(5.1)	(5.1)	(5.1)
43	Retirements & Transfers		0.0	(7.8)	(7.8)	0.0	(9.7)	(9.7)	0.0	0.0	0.0	0.0	0.0	0.0
44	IFRS amortization reclassification		0.0	(4.3)	(4.3)	0.0	(4.3)	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0
45	Accum Amort - End of Year		927.5	915.5	(12.0)	981.0	955.4	(25.6)	1,008.4	1,010.1	1.6	1,068.3	1,129.5	1,194.6
46	Net Contributions - End of Year		1,764.9	1,785.3	20.3	1,855.4	1,926.1	70.6	2,082.4	2,025.5	(56.9)	2,150.4	2,270.3	2,377.6

BC Hydro
F23-F25 RRA

Schedule 12.0
Page 68

Assets - Total (Excluding DSM and IPP Capital Leases)
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Gross Assets in Service													
1	Opening Balance		24,956.3	24,956.3	0.0	26,303.4	26,123.6	(179.8)	27,504.6	27,504.6	0.0	29,150.1	30,599.9	32,081.4
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	14.2	14.2	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L30	1,391.0	1,236.1	(154.9)	1,459.0	1,433.4	(25.7)	1,445.2	1,691.4	246.2	1,494.8	1,525.4	15,552.3
4	Retirements & Transfers		(43.9)	(68.8)	(24.9)	(46.8)	(66.6)	(19.9)	(50.0)	(46.0)	4.0	(45.1)	(43.9)	(43.9)
5	Closing Balance		26,303.4	26,123.6	(179.8)	27,715.7	27,504.6	(211.1)	28,899.9	29,150.1	250.2	30,599.9	32,081.4	47,589.8
	Accumulated Amortization													
6	Opening Balance		1,644.1	1,644.1	0.0	2,529.5	2,494.5	(35.0)	3,360.9	3,360.9	0.0	4,334.1	5,294.0	6,282.8
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Amortization on Existing Assets		856.8	857.6	0.8	823.7	824.8	1.1	902.8	945.7	42.9	930.1	899.2	864.3
9	Amortization on Additions	13.0 L44	28.6	28.2	(0.4)	80.7	80.8	0.1	26.6	27.4	0.9	29.6	88.9	172.7
10	Amortization on Electrification	13.0 L47	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.7	2.1
11	Accelerated Amort on Burrard		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Retirements & Transfers		0.0	(35.4)	(35.4)	0.0	(39.2)	(39.2)	0.0	0.0	0.0	0.0	0.0	0.0
13	Closing Balance		2,529.5	2,494.5	(35.0)	3,434.0	3,360.9	(73.0)	4,290.3	4,334.1	43.8	5,294.0	6,282.8	7,321.9
14	**Net Assets in Service (Year-End)**		23,773.9	23,629.1	(144.8)	24,281.7	24,143.7	(138.0)	24,609.6	24,816.0	206.4	25,305.9	25,798.5	40,267.9

BC Hydro
F23-F25 RRA

Schedule 12.1
Page 69

Assets - Business Support
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Gross Assets in Service													
1	Opening Balance		1,920.1	1,920.1	0.0	2,167.0	2,083.0	(84.0)	2,353.5	2,353.5	0.0	2,530.7	2,759.5	3,030.6
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	14.2	14.2	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L54	252.5	194.4	(58.1)	202.5	285.3	82.8	229.3	181.2	(48.1)	233.6	276.2	161.1
4	Retirements & Transfers		(5.5)	(31.5)	(25.9)	(5.6)	(29.0)	(23.4)	(6.0)	(3.9)	2.1	(4.8)	(5.1)	(3.8)
5	Closing Balance		2,167.0	2,083.0	(84.0)	2,363.9	2,353.5	(10.4)	2,576.8	2,530.7	(46.0)	2,759.5	3,030.6	3,187.9
	Accumulated Amortization													
6	Opening Balance		372.3	372.3	0.0	562.2	535.9	(26.3)	699.5	699.5	0.0	915.9	1,116.1	1,323.8
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Amortization on Existing Assets		174.0	173.4	(0.5)	149.0	146.9	(2.1)	179.6	206.7	27.2	185.4	163.3	137.1
9	Amortization on Additions	13.0 L59	15.9	13.2	(2.8)	41.4	41.0	(0.4)	12.1	9.6	(2.5)	14.9	44.4	68.3
10	Retirements & Transfers		0.0	(23.0)	(23.0)	0.0	(24.2)	(24.2)	0.0	0.0	0.0	0.0	0.0	0.0
11	Closing Balance		562.2	535.9	(26.3)	752.5	699.5	(53.0)	891.2	915.9	24.6	1,116.1	1,323.8	1,529.3
12	**Net Assets in Service (Year-End)**		1,604.8	1,547.1	(57.7)	1,611.3	1,654.0	42.6	1,685.6	1,614.9	(70.7)	1,643.4	1,706.8	1,658.6

BC Hydro
F23-F25 RRA

Schedule 12.2
Page 70

Assets - Generation
($ million)

Line	Column	Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Gross Assets in Service													
1	Opening Balance		9,304.7	9,304.7	0.0	9,643.1	9,682.3	39.2	10,002.3	10,002.3	0.0	10,391.2	10,830.4	11,049.5
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L51	342.6	372.4	29.9	486.3	323.5	(162.8)	272.4	393.2	120.8	443.2	223.2	14,226.6
4	Retirements & Transfers		(4.1)	5.2	9.3	(4.4)	(3.6)	0.8	(4.4)	(4.2)	0.1	(4.0)	(4.1)	(3.8)
5	Closing Balance		9,643.1	9,682.3	39.2	10,125.0	10,002.3	(122.8)	10,270.3	10,391.2	120.9	10,830.4	11,049.5	25,272.3
	Accumulated Amortization													
6	Opening Balance		428.4	428.4	0.0	689.3	687.4	(1.9)	955.9	955.9	0.0	1,224.6	1,495.4	1,771.9
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Amortization on Existing Assets		256.7	257.2	0.5	253.7	258.2	4.5	275.3	264.1	(11.1)	265.9	264.0	262.0
9	Amortization on Additions	13.0 L56	4.1	5.5	1.3	13.1	12.0	(1.1)	3.2	4.5	1.3	5.0	12.5	46.1
10	Accelerated Amort on Burrard		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Retirements & Transfers		0.0	(3.7)	(3.7)	0.0	(1.8)	(1.8)	0.0	0.0	0.0	0.0	0.0	0.0
12	Closing Balance		689.3	687.4	(1.9)	956.1	955.9	(0.2)	1,234.4	1,224.6	(9.8)	1,495.4	1,771.9	2,080.0
13	**Net Assets in Service (Year-End)**		8,953.8	8,994.9	41.1	9,168.9	9,046.4	(122.5)	9,035.9	9,166.7	130.8	9,335.0	9,277.6	23,192.3

BC Hydro
F23-F25 RRA

Schedule 12.3
Page 71

Assets - Transmission
($ million)

Line		Reference	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Gross Assets in Service													
1	Opening Balance		7,697.4	7,697.4	0.0	7,984.1	7,886.5	(97.7)	8,174.5	8,174.5	0.0	8,658.3	8,924.6	9,384.3
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L52	293.8	199.7	(94.1)	229.5	288.5	59.0	440.7	490.3	49.6	272.3	465.2	622.6
4	Retirements & Transfers		(7.0)	(10.6)	(3.6)	(7.3)	(0.5)	6.8	(7.7)	(6.4)	1.3	(6.0)	(5.6)	(6.0)
5	Closing Balance		7,984.1	7,886.5	(97.7)	8,206.4	8,174.5	(31.9)	8,607.5	8,658.3	50.9	8,924.6	9,384.3	10,000.8
	Accumulated Amortization													
6	Opening Balance		454.0	454.0	0.0	682.4	679.3	(3.1)	902.7	902.7	0.0	1,162.0	1,413.0	1,669.3
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Amortization on Existing Assets		225.9	227.0	1.2	223.1	221.9	(1.2)	228.7	253.9	25.2	247.7	243.8	239.2
9	Amortization on Additions	13.0 L57-L10	2.5	2.2	(0.3)	7.7	8.6	0.9	5.2	5.4	0.3	3.1	11.9	24.8
10	Amortization on Electrification	13.0 L45	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.6	1.7
11	Retirements & Transfers		0.0	(4.0)	(4.0)	0.0	(7.1)	(7.1)	0.0	0.0	0.0	0.0	0.0	0.0
12	Closing Balance		682.4	679.3	(3.1)	913.2	902.7	(10.5)	1,136.5	1,162.0	25.5	1,413.0	1,669.3	1,935.0
13	**Net Assets in Service (Year-End)**		7,301.7	7,207.2	(94.6)	7,293.2	7,271.8	(21.4)	7,471.0	7,496.3	25.4	7,511.7	7,715.0	8,065.8

BC Hydro
F23-F25 RRA

Schedule 12.4
Page 72

Assets - Distribution
($ million)

			F2020			F2021			F2022			F2023	F2024	F2025
		Reference	Decision	Actual	Diff	Decision	Actual	Diff	Decision	Forecast	Diff	Plan	Plan	Plan
Line	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Gross Assets in Service													
1	Opening Balance		6,034.2	6,034.2	0.0	6,509.1	6,471.9	(37.3)	6,974.4	6,974.4	0.0	7,569.8	8,085.3	8,617.0
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L53	502.2	469.6	(32.6)	540.7	536.0	(4.7)	502.9	626.8	123.9	545.7	560.8	542.0
4	Retirements & Transfers		(27.2)	(31.9)	(4.7)	(29.5)	(33.5)	(4.0)	(31.9)	(31.4)	0.5	(30.2)	(29.1)	(30.2)
5	Closing Balance		6,509.1	6,471.9	(37.3)	7,020.4	6,974.4	(46.0)	7,445.3	7,569.8	124.5	8,085.3	8,617.0	9,128.8
	Accumulated Amortization													
6	Opening Balance		389.4	389.4	0.0	595.6	591.9	(3.8)	802.9	802.9	0.0	1,031.7	1,269.5	1,517.9
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Amortization on Existing Assets		200.3	200.0	(0.3)	198.0	197.9	(0.1)	219.3	221.0	1.6	231.1	228.1	226.0
9	Amortization on Additions	13.0 L58-L10	6.0	7.4	1.3	18.5	19.2	0.7	6.0	7.9	1.8	6.7	20.1	33.4
10	Amortization on Electrification	13.0 L46	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4
11	Retirements & Transfers		0.0	(4.8)	(4.8)	0.0	(6.1)	(6.1)	0.0	0.0	0.0	0.0	0.0	0.0
12	Closing Balance		595.6	591.9	(3.8)	812.2	802.9	(9.3)	1,028.2	1,031.7	3.5	1,269.5	1,517.9	1,777.6
13	**Net Assets in Service (Year-End)**		5,913.5	5,880.0	(33.5)	6,208.2	6,171.5	(36.7)	6,417.1	6,538.1	121.0	6,815.8	7,099.1	7,351.1

BC Hydro
F23-F25 RRA

Schedule 13.0
Page 73

Capital Expenditures and Additions
($ million)

Line		Reference Column	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Capital Expenditures													
1	Generation Growth		3.2	2.6	(0.6)	0.0	0.8	0.8	5.0	0.0	(5.0)	0.0	0.0	0.0
2	Generation - Waneta 2/3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Generation Sustaining		341.8	302.5	(39.3)	435.5	299.2	(136.3)	383.4	376.6	(6.8)	300.9	311.0	500.4
4	Transmission Growth		185.0	159.6	(25.4)	198.9	121.9	(77.0)	142.9	79.7	(63.2)	125.2	151.5	117.2
5	Transmission Sustaining		222.6	223.3	0.7	286.5	254.4	(32.1)	325.6	349.4	23.8	349.9	377.9	393.4
6	Distribution Growth		299.9	339.7	39.8	284.6	390.5	105.9	306.7	321.1	14.4	326.6	331.5	333.7
7	Distribution Sustaining		187.6	176.2	(11.4)	176.9	204.1	27.2	219.3	217.7	(1.6)	193.8	190.9	182.4
8	Site C Project		1,530.0	1,619.1	89.1	1,535.5	1,725.0	189.5	1,361.0	2,789.5	1,428.5	2,708.3	1,754.9	1,043.2
9	Technology		95.6	133.0	37.4	56.0	90.8	34.8	69.2	107.1	37.9	109.4	88.2	86.6
10	Properties		58.9	56.4	(2.5)	55.3	56.0	0.7	75.6	51.5	(24.1)	83.4	81.7	92.3
11	Fleet & Other		63.6	59.0	(4.6)	75.1	54.8	(20.3)	70.3	60.7	(9.6)	80.1	76.1	57.6
12	Subtotal		2,988.3	3,071.4	83.1	3,104.2	3,197.5	93.3	2,959.0	4,353.4	1,394.4	4,277.5	3,363.6	2,806.8
	Electrification Plan													
13	Transmission Growth				0.0			0.0		5.5	5.5	22.6	51.1	45.3
14	Distribution Growth				0.0			0.0		1.0	1.0	4.0	9.1	8.0
15	Distribution Sustaining							0.0		0.0	0.0	2.0	2.0	2.0
16	Subtotal		0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.5	6.5	28.7	62.2	55.3
17	Total		2,988.3	3,071.4	83.1	3,104.2	3,197.5	93.3	2,959.0	4,359.9	1,400.9	4,306.2	3,425.8	2,862.1
	Total Capital Additions													
18	Generation		314.7	359.5	44.8	296.9	102.6	(194.3)	272.4	393.2	120.8	443.2	223.2	249.3
19	Generation - Waneta 2/3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Transmission		293.8	199.7	(94.1)	229.5	288.5	59.0	440.7	489.8	49.1	257.7	436.0	542.4
21	Distribution		502.2	469.6	(32.6)	540.7	536.0	(4.7)	502.9	626.6	123.7	542.6	553.7	531.1
22	Site C Project		27.9	12.9	(15.0)	189.4	220.9	31.5	0.0	0.0	0.0	0.0	0.0	13,977.3
23	Technology		147.6	93.7	(53.9)	75.5	164.9	89.4	94.3	79.3	(14.9)	130.6	119.5	78.6
24	Properties		39.9	44.3	4.4	55.6	70.9	15.3	59.8	38.5	(21.3)	32.7	65.9	25.7
25	Fleet & Other		65.0	56.4	(8.6)	71.3	49.5	(21.9)	75.2	63.3	(11.9)	70.3	90.9	56.8
26	Subtotal		1,391.0	1,236.1	(154.9)	1,459.0	1,433.4	(25.7)	1,445.2	1,690.7	245.5	1,477.0	1,489.1	15,461.3
	Electrification Plan													
27	Transmission				0.0			0.0		0.5	0.5	14.6	29.2	80.1
28	Distribution				0.0			0.0		0.2	0.2	3.2	7.0	10.9
29	Subtotal		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.7	17.8	36.3	91.0
30	Total		1,391.0	1,236.1	(154.9)	1,459.0	1,433.4	(25.7)	1,445.2	1,691.4	246.2	1,494.8	1,525.4	15,552.3
	Unfinished Construction													
31	Beginning of Year		4,553.3	4,553.3	0.0	6,150.7	6,373.4	222.8	8,128.5	8,128.5	0.0	10,797.0	13,608.4	15,508.7
32	Adjustments		0.0	(15.2)	(15.2)	0.0	(9.0)	(9.0)	0.0	0.0	0.0	0.0	0.0	0.0
33	Change in Unfinished		1,597.4	1,835.3	237.9	1,645.2	1,764.1	118.9	1,513.8	2,668.5	1,154.7	2,811.3	1,900.4	(12,690.2)
34	End of Year		6,150.7	6,373.4	222.8	7,795.8	8,128.5	332.7	9,642.3	10,797.0	1,154.7	13,608.4	15,508.7	2,818.5
35	Mid-Year Balance		5,352.0	5,463.4	111.4	6,973.2	7,251.0	277.8	8,885.4	9,462.8	577.4	12,202.7	14,558.6	9,163.6

BC Hydro
F23-F25 RRA

Schedule 13.0
Page 74

Capital Expenditures and Additions
($ million)

Line		Reference	F2020			F2021			F2022			F2023	F2024	F2025
			Decision	Actual	Diff	Decision	Actual	Diff	Decision	Forecast	Diff	Plan	Plan	Plan
Line		Column	1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Amortization on Additions													
36	Generation		3.9	5.3	1.5	11.4	9.8	(1.6)	3.2	4.5	1.3	5.0	12.5	17.8
37	Generation - Waneta 2/3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	Transmission		2.5	2.2	(0.3)	7.7	8.6	0.9	5.2	5.4	0.3	3.1	11.9	24.8
39	Distribution		6.0	7.4	1.3	18.5	19.2	0.7	6.0	7.9	1.8	6.7	20.1	33.4
40	Site C Project		0.3	0.1	(0.2)	1.7	2.3	0.5	0.0	0.0	0.0	0.0	0.0	28.3
41	Technology		13.6	9.9	(3.7)	34.0	32.1	(1.9)	8.8	6.6	(2.2)	11.8	34.0	51.1
42	Properties		0.7	0.7	(0.0)	2.5	2.0	(0.4)	1.0	0.8	(0.3)	0.5	2.2	3.8
43	Fleet & Other		1.7	2.6	1.0	4.9	6.9	1.9	2.3	2.2	(0.1)	2.5	8.3	13.5
44	Subtotal		28.6	28.2	(0.4)	80.7	80.8	0.1	26.6	27.4	0.9	29.6	88.9	172.7
	Electrification Plan													
45	Transmission				0.0			0.0		0.0	0.0	0.1	0.6	1.7
46	Distribution				0.0			0.0		0.0	0.0	0.0	0.2	0.4
47	Subtotal		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.7	2.1
48	Less: Depreciation Study on Additions									(0.1)	(0.1)	0.0	0.0	0.0
49	Less: Electric Vehicle Costs Additions									(0.1)	(0.1)	0.0	0.0	0.0
50	Total		28.6	28.2	(0.4)	80.7	80.8	0.1	26.6	27.3	0.7	29.8	89.6	174.7
	Summary of Additions													
51	Generation		342.6	372.4	29.9	486.3	323.5	(162.8)	272.4	393.2	120.8	443.2	223.2	14,226.6
52	Transmission		293.8	199.7	(94.1)	229.5	288.5	59.0	440.7	490.3	49.6	272.3	465.2	622.6
53	Distribution		502.2	469.6	(32.6)	540.7	536.0	(4.7)	502.9	626.8	123.9	545.7	560.8	542.0
54	Business Support		252.5	194.4	(58.1)	202.5	285.3	82.8	229.3	181.2	(48.1)	233.6	276.2	161.1
55	Total		1,391.0	1,236.1	(154.9)	1,459.0	1,433.4	(25.7)	1,445.2	1,691.4	246.2	1,494.8	1,525.4	15,552.3
	Summary of Amortization on Additions													
56	Generation		4.1	5.5	1.3	13.1	12.0	(1.1)	3.2	4.5	1.3	5.0	12.5	46.1
57	Transmission		2.5	2.2	(0.3)	7.7	8.6	0.9	5.2	5.5	0.3	3.3	12.5	26.5
58	Distribution		6.0	7.4	1.3	18.5	19.2	0.7	6.0	7.9	1.8	6.7	20.3	33.8
59	Business Support		15.9	13.2	(2.8)	41.4	41.0	(0.4)	12.1	9.6	(2.5)	14.9	44.4	68.3
60	Total		28.6	28.2	(0.4)	80.7	80.8	0.1	26.6	27.4	0.9	29.8	89.6	174.7
	Composite Depreciation Rate													
61	Generation		2.45%			2.46%			2.38%			2.23%	2.30%	2.26%
62	Transmission		1.70%			2.31%			2.34%			2.43%	2.61%	2.66%
63	Distribution		2.40%			2.40%			2.40%			2.45%	2.45%	2.45%
64	Site C Project		1.95%			1.27%			0.00%			0.00%	0.00%	0.40%
65	Technology		18.38%			18.22%			18.68%			18.06%	17.36%	17.19%
66	Properties		3.59%			3.73%			3.49%			3.21%	3.39%	3.77%
67	Fleet & Other		5.08%			4.55%			6.05%			7.24%	7.01%	7.08%
	Electrification Plan													
68	Transmission									2.00%		2.00%	2.00%	2.00%
69	Distribution									2.40%		2.40%	2.40%	2.40%

BC Hydro
F23-F25 RRA

Schedule 14.0
Page 75

Domestic Energy Sales and Revenue

Line	Reference Column	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Domestic Energy Sales (GWh)												
1	Residential	17,751	17,993	242	17,927	18,982	1,055	18,856	19,808	952	19,676	19,913	20,038
2	Light Industrial and Commercial	18,631	18,692	60	18,744	18,091	(653)	18,909	18,291	(617)	18,785	18,730	18,642
3	Large Industrial	13,527	13,383	(145)	13,203	12,438	(765)	12,982	12,437	(545)	13,183	14,042	14,982
4	Irrigation	97	72	(25)	99	63	(37)	79	79	1	80	81	81
5	Street Lighting	288	212	(76)	291	213	(78)	213	227	14	215	210	209
6	New Westminster & Tongass	585	465	(120)	591	457	(134)	497	508	11	506	512	516
7	Fortis	683	586	(97)	695	584	(111)	602	622	20	618	615	637
8	Seattle City Light	389	307	(82)	388	311	(78)	310	310	0	310	310	310
9	Liquefied Natural Gas	6	16	9	0	0	0	0	0	0	0	0	0
10	Other	0	205	205	0	0	0	0	1	1	3	6	10
11	Subtotal	51,958	51,931	(27)	51,940	51,139	(801)	52,448	52,284	(164)	53,377	54,419	55,426
	<u>Electrification Plan</u>												
12	Residential	0	0	0	0	0	0	0	(30)	(30)	(22)	(12)	1
13	Light Industrial and Commercial	0	0	0	0	0	0	0	(36)	(36)	(31)	42	135
14	Large Industrial	0	0	0	0	0	0	0	(13)	(13)	367	1,284	2,095
15	Subtotal	0	0	0	0	0	0	0	(78)	(78)	313	1,314	2,231
16	Total	51,958	51,931	(27)	51,940	51,139	(801)	52,448	52,206	(242)	53,691	55,733	57,657
	Domestic Revenues ($ million)												
17	Residential	2,149.5	2,168.8	19.4	2,140.4	2,210.2	69.8	2,234.0	2,367.6	133.6	2,355.2	2,383.9	2,400.4
18	Light Industrial and Commercial	1,929.4	1,942.0	12.6	1,905.9	1,830.4	(75.6)	1,954.1	1,910.4	(43.6)	1,961.4	1,956.3	1,947.2
19	Large Industrial	875.7	848.4	(27.2)	852.2	761.7	(90.5)	842.3	785.6	(56.7)	831.6	891.9	948.4
20	Irrigation	7.9	6.4	(1.5)	7.8	5.8	(2.0)	6.9	7.2	0.3	7.3	7.3	7.4
21	Street Lighting	56.0	40.2	(15.8)	55.9	42.1	(13.8)	40.2	44.8	4.7	42.5	41.5	41.3
22	New Westminster & Tongass	40.2	31.8	(8.4)	39.9	30.7	(9.2)	33.6	34.6	1.0	34.8	35.1	35.3
23	Fortis	49.5	41.0	(8.5)	49.4	39.6	(9.8)	41.1	42.4	1.3	42.2	42.0	43.2
24	Seattle City Light	36.1	29.7	(6.4)	35.9	30.0	(5.9)	30.2	30.0	(0.2)	30.0	30.0	30.0
25	Liquefied Natural Gas	0.5	1.3	0.7	0.0	0.00	0.0	0.00	0.00	0.0	0.00	0.00	0.00
26	Other		5.4	5.4	0.0	0.0	0.0	0.0	0.5	0.5	1.0	1.8	2.8
27	Subtotal	5,144.8	5,114.9	(29.8)	5,087.4	4,950.4	(137.0)	5,182.4	5,223.2	40.9	5,306.0	5,389.8	5,456.0
	<u>Electrification Plan</u>												
28	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(3.3)	(3.3)	(2.5)	(1.4)	0.1
29	Light Industrial and Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(2.9)	(2.9)	(0.2)	10.7	22.3
30	Large Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.3)	(1.3)	22.4	73.6	122.5
31	Subtotal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(7.6)	(7.6)	19.7	82.9	144.9
32	Revenue from Deferral Account Rate Rider	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	(106.5)	(55.3)	(28.9)
33	Total	5,144.8	5,115.1	(29.6)	5,087.4	4,950.4	(137.0)	5,182.4	5,215.7	33.3	5,219.2	5,417.5	5,571.9
34	**Deferral Account Rate Rider**	0.0%	0.0%		0.0%	0.0%		0.0%	0.0%		-2.0%	-1.0%	-0.5%

BC Hydro
F23-F25 RRA

Schedule 14.0
Page 76

Domestic Energy Sales and Revenue

Line		F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Column	1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Average Revenues ($/MWh)												
35	Residential	121.1	120.5	(0.6)	119.4	116.4	(3.0)	118.5	119.5	1.1	119.7	119.7	119.8
36	Light Industrial and Commercial	103.6	103.9	0.3	101.7	101.2	(0.5)	103.3	104.4	1.1	104.4	104.4	104.5
37	Large Industrial	64.7	63.4	(1.3)	64.5	61.2	(3.3)	64.9	63.2	(1.7)	63.1	63.5	63.3
38	Irrigation	81.9	88.9	7.0	78.1	92.5	14.4	87.4	90.7	3.3	90.7	90.7	90.7
39	Street Lighting	194.1	189.2	(4.9)	192.2	197.5	5.3	189.1	197.6	8.5	197.7	197.7	197.7
40	New Westminster & Tongass	68.8	68.3	(0.4)	67.5	67.1	(0.4)	67.6	68.2	0.6	68.8	68.6	68.4
41	Fortis	72.5	70.0	(2.5)	71.0	67.7	(3.3)	68.2	68.2	(0.1)	68.3	68.4	67.7
42	Seattle City Light	92.7	96.6	3.9	92.4	96.5	4.1	97.4	96.7	(0.7)	96.7	96.7	96.7
43	Liquefied Natural Gas	85.4	80.0	(5.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	Other	0.0	26.1	26.1	0.0	0.0	0.0	0.0	419.1	419.1	351.7	306.2	285.1
	Electrification Plan												
45	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	112.2	112.2	112.2	112.2	112.2
46	Light Industrial and Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	82.3	82.3	5.8	252.8	164.9
47	Large Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.9	100.9	61.2	57.3	58.5
48	Total (Excluding Misc Rev)	99.0	98.5	(0.5)	97.9	96.8	(1.1)	98.8	99.9	1.1	97.2	97.2	96.6
	Baseline												
49	COVID-19 Residential Grants to CCF	0.0	0.0	0.0	0.0	(37.3)	(37.3)	0.0	0.0	0.0	0.0	0.0	0.0
50	COVID-19 SGS Waivers to MCPP	0.0	0.0	0.0	0.0	(6.3)	(6.3)	0.0	0.0	0.0	0.0	0.0	0.0
51	Skagit and Ancillary Revenue to HDA	36.1	29.7	(6.4)	35.9	30.0	(5.9)	30.2	30.0	(0.2)	30.0	30.0	30.0
52	Load Variance	5,099.7	5,079.5	(20.3)	5,036.3	4,950.5	(85.8)	5,187.7	5,218.6	30.9	5,306.8	5,510.9	5,765.2
53	Biomass Energy Program Variance	9.0	5.8	(3.2)	15.2	13.5	(1.7)	15.9	18.9	2.9	21.7	18.5	17.4
54	Total	5,144.8	5,114.9	(29.8)	5,087.4	4,950.4	(137.0)	5,233.8	5,267.4	33.6	5,358.5	5,559.4	5,812.6

Miscellaneous Revenue
($ million)

			F2020			F2021			F2022			F2023	F2024	F2025
		Reference	Decision	Actual	Diff	Decision	Actual	Diff	Decision	Forecast	Diff	Plan	Plan	Plan
Line	Column		1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
1	**Gross Miscellaneous Revenue**	L46	240.6	247.3	6.7	247.0	261.1	14.1	289.0	300.5	11.5	288.5	292.9	295.3
2	**Deferral Account Additions**	L47	(3.1)	(1.3)	1.8	(3.5)	(5.0)	(1.5)	(15.5)	(15.5)	(0.0)	(2.8)	(3.7)	(2.4)
3	**Regulatory Account Additions**	L48	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Subtotal before Recoveries**		237.5	246.0	8.5	243.6	256.1	12.6	273.5	285.0	11.5	285.7	289.2	292.8
5	**Current Miscellaneous Revenue**	L49	237.5	246.0	8.5	243.6	256.1	12.6	273.5	285.0	11.5	285.7	289.2	292.8
	Generation													
6	Amortization of Contributions	11.0 L7	0.3	0.3	0.0	0.2	0.3	0.0	0.2	0.2	0.0	0.2	0.2	0.2
7	Other		1.6	2.2	0.6	1.7	2.3	0.7	1.9	1.8	(0.1)	1.9	1.8	1.6
8	Total		1.9	2.5	0.6	1.9	2.6	0.7	2.2	2.1	(0.1)	2.1	2.0	1.8
	Transmission													
9	External OATT	3.4 L74	15.9	10.7	(5.2)	15.9	14.1	(1.8)	11.1	11.6	0.5	12.2	12.3	11.9
10	FortisBC Wheeling Agreement		5.2	5.2	(0.0)	5.3	5.2	(0.1)	5.3	5.3	(0.0)	5.7	6.0	6.3
11	Secondary Revenue		6.0	7.1	1.2	6.2	7.3	1.1	7.1	6.7	(0.4)	6.8	6.8	6.9
12	Interconnections		2.2	6.4	4.2	2.2	8.3	6.1	4.6	6.1	1.5	6.1	4.2	3.3
13	Amortization of Contributions	11.0 L18:L19-L14	14.6	14.6	0.1	15.0	15.3	0.3	11.0	12.0	1.0	12.4	11.9	12.5
14	NTL Supplemental Charge		2.3	2.3	0.0	2.3	2.4	0.1	2.4	2.4	(0.0)	2.4	2.4	2.4
15	Total		46.1	46.4	0.3	46.8	52.6	5.8	41.4	44.0	2.6	45.5	43.6	43.2
	Distribution													
16	Secondary Use Revenue & Other		14.1	17.0	2.8	14.1	20.4	6.3	16.9	18.9	2.0	19.0	19.1	16.9
17	Amortization of Contributions	11.0 L29:L31-L26	44.8	49.1	4.3	47.9	48.7	0.8	51.7	52.1	0.4	55.6	59.1	62.6
18	Interconnections		0.0	0.0	0.0	0.0		0.0		0.9	0.9	0.9	0.9	0.9
19	Total		58.9	66.0	7.1	62.0	69.1	7.1	68.6	71.9	3.2	75.5	79.0	80.3
	Customer Care													
20	Meter/Trans Rents & Power Factor Surcharges		14.6	16.1	1.5	14.9	16.4	1.5	16.2	16.2	0.0	16.6	16.9	17.2
21	Smart Metering & Infrastructure Impact		2.1	2.2	0.1	1.7	1.6	(0.1)	1.5	1.5	0.0	1.5	1.4	1.3
22	Diversion Net Recoveries		0.1	0.2	0.1	0.1	0.1	(0.0)	0.1	0.1	0.0	0.1	0.1	0.1
23	Other Operating Recoveries		4.5	4.1	(0.3)	4.6	4.0	(0.6)	4.2	4.2	0.0	4.2	4.2	4.2
24	Customer Crisis Fund Rider Revenue		5.3	4.4	(0.9)	5.3	2.9	(2.4)	0.5	0.5	0.0	0.0	0.0	0.0
25	Other		3.0	3.1	0.1	3.0	4.0	0.9	3.0	3.0	0.0	3.0	3.0	3.0
	Waneta 2/3													
26	Lease revenue from Teck		75.2	75.2	0.0	76.7	76.7	0.0	78.2	78.2	0.0	79.8	81.4	83.0
27	Teck portion of operating costs		5.7	5.4	(0.3)	5.9	5.8	(0.0)	6.1	6.1	0.0	5.9	6.1	6.3
28	Teck portion of water rentals		3.5	3.3	(0.2)	3.7	3.2	(0.5)	3.5	3.4	(0.0)	3.5	3.7	3.8
29	Teck portion of property taxes		0.6	0.9	0.3	0.6	0.8	0.2	0.8	0.8	(0.0)	0.8	0.8	0.9
30	Subtotal		84.9	84.7	(0.2)	86.9	86.5	(0.4)	88.6	88.5	(0.1)	90.1	92.0	94.0
31	Total		114.5	114.8	0.3	116.4	115.5	(0.9)	114.1	114.1	(0.1)	115.5	117.6	119.8
	Business Support													
32	Corporate General Rents		3.7	3.9	0.2	3.8	2.8	(1.0)	3.6	3.1	(0.6)	3.6	3.6	3.6
33	Late Payment Charges		7.9	7.1	(0.8)	8.1	7.8	(0.3)	7.9	7.9	0.0	7.9	7.9	7.9
34	MMBU Secondary Revenue		3.8	3.9	0.1	3.8	4.8	1.0	3.3	3.3	0.0	3.3	3.3	3.5

Miscellaneous Revenue
($ million)

Line		F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Reference Column	1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
35	Low Carbon Fuel Credits							31.4	31.4	0.0	31.4	31.4	31.4
36	Other	0.7	1.4	0.7	0.7	1.0	0.3	0.9	7.3	6.4	0.8	0.8	1.2
37	Total	16.1	16.4	0.2	16.4	16.3	(0.0)	47.1	52.9	5.8	47.1	47.0	47.7
38	**Total Before Regulatory Accounts**	237.5	246.0	8.5	243.6	256.1	12.6	273.5	285.0	11.5	285.7	289.2	292.8
	Deferral Account Additions												
39	Waneta 2/3												
40	Lease revenue from Teck	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Teck portion of capital expenditures	3.1	1.3	(1.8)	3.5	5.0	1.5	15.5	15.5	0.0	2.8	3.7	2.4
42	Low Carbon Fuel Credits					0.0		0.0	0.0	0.0	0.0	0.0	0.0
43	Subtotal	3.1	1.3	(1.8)	3.5	5.0	1.5	15.5	15.5	0.0	2.8	3.7	2.4
	Regulatory Account Additions												
44	Smart Metering & Infrastructure Impact	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Subtotal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
46	**Total Gross Miscellaneous Revenue**	240.6	247.3	6.7	247.0	261.1	14.1	289.0	300.5	11.5	288.5	292.9	295.3
47	**Transfers to NHDA**	(3.1)	(1.3)	1.8	(3.5)	(5.0)	(1.5)	(15.5)	(15.5)	(0.0)	(2.8)	(3.7)	(2.4)
48	**Transfers to Regulatory Accounts**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	**Total Current Miscellaneous Revenue**	237.5	246.0	8.5	243.6	256.1	12.6	273.5	285.0	11.5	285.7	289.2	292.8

BC Hydro
F23-F25 RRA

Schedule 16.0
Page 79

Full-Time Equivalents (FTEs)

Line		F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Reference Column	1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Integrated Planning												
1	Energy Planning and Analytics	44	45	1	44	45	1	44	44	0	44	44	45
2	Dam Safety	37	33	(5)	37	36	(1)	39	39	0	39	39	41
3	Asset Planning	190	188	(2)	190	198	7	200	200	0	211	211	211
4	Interconnections and Shared Assets	47	44	(3)	47	48	1	46	46	0	47	47	47
5	Engineering Design	457	457	1	457	432	(25)	408	411	3	413	414	415
6	Engineering Services	189	180	(9)	189	224	35	239	243	3	246	247	248
7	Business Unit Support	3	3	(0)	3	3	0	3	3	0	3	3	3
8	Total	967	950	(17)	967	986	19	980	986	6	1,004	1,005	1,010
	Capital Infrastructure Project Delivery												
9	Project Delivery	450	418	(33)	450	434	(17)	431	430	(2)	434	439	439
10	Indigenous Relations	69	69	0	69	60	(9)	74	75	1	79	74	74
11	Environment	94	93	(1)	94	93	(1)	95	95	0	95	95	95
12	Properties	123	116	(6)	123	116	(6)	123	123	0	123	123	123
13	Business Unit Support	3	3	0	3	3	(0)	3	3	0	3	3	3
14	Total	739	699	(39)	739	706	(32)	726	725	(1)	733	733	733
	Operations												
15	Program and Contract Management	228	251	23	228	272	44	280	284	4	317	318	318
16	Line Field Operations	922	876	(46)	922	907	(16)	924	925	1	925	925	925
17	Stations Field Operations	777	712	(65)	777	710	(67)	724	725	1	745	745	760
18	Distribution Design and Customer Connections	379	356	(23)	379	370	(9)	379	379	0	385	391	394
19	Construction Services	397	422	25	397	416	19	397	396	(1)	396	396	396
20	Generation System Operations	89	91	1	89	89	(0)	81	82	1	82	82	82
21	Transmission and Distribution System Operations	197	195	(2)	197	204	7	197	198	1	201	201	201
22	Business Unit Support	5	7	2	5	5	(0)	4	4	0	6	6	6
23	Total	2,995	2,910	(85)	2,995	2,972	(23)	2,985	2,992	7	3,057	3,063	3,082
	Safety & Compliance												
24	Safety	118	120	2	118	117	(1)	112	111	(1)	110	110	111
25	Learning and Development	313	333	20	295	290	(6)	246	245	(1)	240	256	274
26	Security and Emergency Management	31	29	(2)	31	29	(2)	33	33	0	34	38	39
27	Reliability Standards Assurance	5	6	1	5	9	4	22	13	(9)	19	22	22
28	Business Unit Support	2	2	0	2	3	1	3	2	(1)	2	2	2
29	Total	469	490	21	452	448	(4)	416	404	(12)	405	428	447

Full-Time Equivalents (FTEs)

Line		F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
Line	Column / Reference	1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Finance, Technology, Supply Chain												
30	Finance	206	203	(3)	206	209	3	211	211	0	211	211	211
31	Technology	269	269	(1)	269	271	2	283	285	2	297	316	316
32	Supply Chain	468	501	33	468	513	45	475	475	0	474	465	459
33	Business Unit Support	3	3	(0)	3	3	0	3	3	0	3	3	3
34	Total	946	975	29	946	996	50	972	974	2	985	995	989
	Customer and Corporate Affairs												
35	Customer Service	479	483	4	479	507	29	492	495	3	504	504	504
36	Conservation and Energy Management	116	116	1	116	119	3	116	116	(0)	122	122	123
37	Communications and Community Engagement	107	103	(5)	107	97	(10)	108	108	(0)	110	110	110
38	Regulatory and Rates	23	24	1	23	23	(0)	23	23	0	26	26	26
39	Business Unit Support	3	3	0	3	3	0	3	3	0	3	3	3
40	Total	728	729	1	728	749	21	742	744	3	765	765	766
	Other												
41	Human Resources	129	128	(1)	129	126	(2)	131	130	(1)	129	129	129
42	Office of the General Counsel	42	39	(2)	42	39	(3)	41	41	0	41	41	41
43	Office of the President and Chief Executive Officer	3	3	0	3	3	0	3	3	0	3	3	3
44	Site C Project	460	445	(15)	472	479	8	504	696	192	721	651	453
45	Corporate Costs	0	0	0	0	0	0	0	0	0	0	0	0
46	Capitalized Costs	0	0	0	0	0	0	0	0	0	0	0	0
47	Total	633	615	(18)	645	648	3	679	870	191	894	824	626
48	**Total**	7,477	7,369	(108)	7,471	7,505	34	7,500	7,696	196	7,842	7,814	7,654
49	**Before Electrification Plan**							7,500	7,696	196	7,799	7,808	7,650
50	**Electrification Plan**								0	0	43	6	4
51	**Total Full Time Equivalents**							7,500	7,696	196	7,842	7,814	7,654

BC Hydro
F23-F25 RRA

Schedule 16.0
Page 81

Full-Time Equivalents (FTEs)

Line		F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Actual	F2021 Diff	F2022 Decision	F2022 Forecast	F2022 Diff	F2023 Plan	F2024 Plan	F2025 Plan
	Reference Column	1	2	3 = 2 - 1	3	4	5 = 4 - 3	6	7	8 = 7 - 6	9	10	11
	Summary												
	Regular Hour FTEs												
52	(excl. Smart Metering & Infrastructure & Site C Project)	6,461	6,330	(131)	6,449	6,474	26	6,446	6,446	0	6,567	6,607	6,642
53	Smart Metering & Infrastructure (SMI)	0	0	0	0	0	0	0	0	0	0	0	0
54	Site C Project	422	403	(19)	431	442	11	459	620	161	638	576	406
55	Subtotal Regular Hour FTEs	6,884	6,733	(150)	6,880	6,916	37	6,905	7,066	161	7,205	7,183	7,048
	Overtime Hour FTEs												
56	(excl. Smart Metering & Infrastructure & Site C Project)	556	594	38	551	551	0	550	554	4	554	556	559
57	Smart Metering & Infrastructure (OT Hour FTEs)	0	0	0	0	0	0	0	0	0	0	0	0
58	Site C Project (OT Hour FTEs)	38	42	4	41	37	(3)	45	75	31	83	75	47
59	Total	7,477	7,369	(108)	7,471	7,505	34	7,500	7,696	196	7,842	7,814	7,654
	Summary of FTE's by Function												
	Regular Hour FTEs												
60	Operating	4,250	4,350	100	4,247	4,461	214	4,309	4,309	1	4,393	4,405	4,425
61	Capital	2,470	2,215	(255)	2,469	2,286	(182)	2,430	2,591	161	2,624	2,589	2,434
62	Deferred	164	168	4	164	169	5	166	166	(0)	189	189	190
63	Total	6,884	6,733	(150)	6,880	6,916	37	6,905	7,066	161	7,205	7,183	7,048
	Overtime Hour FTEs												
64	Operating	220	360	141	219	336	117	235	238	3	244	242	241
65	Capital	373	274	(100)	373	252	(121)	360	391	31	393	388	364
66	Deferred	0	2	2	0	1	1	0	0	(0)	0	0	0
67	Total	593	636	42	592	589	(3)	595	630	35	637	631	605
	Total FTEs by Function												
68	Operating	4,470	4,710	241	4,466	4,797	331	4,544	4,548	4	4,637	4,647	4,666
69	Capital	2,843	2,488	(355)	2,841	2,538	(304)	2,790	2,982	192	3,016	2,978	2,798
70	Deferred	164	170	6	164	170	6	166	166	(0)	189	189	190
71	Total	7,477	7,369	(108)	7,471	7,505	34	7,500	7,696	196	7,842	7,814	7,654

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix B

Draft Orders

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

BEFORE:
Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On August 31, 2021, the British Columbia Hydro and Power Authority (BC Hydro) filed its Fiscal 2023 to Fiscal 2025 Revenue Requirements Application (**Application**) with the British Columbia Utilities Commission (**BCUC**) pursuant to sections 58 to 61 and 90 of the *Utilities Commission Act* (**UCA**) and s. 15 of the *Administrative Tribunals Act (***ATA***)*, requesting, among other things:

(i) Interim and, after certain future determinations in other proceedings, permanent approval of an increase in rates by 0.62 per cent, effective April 1, 2022, 0.97 per cent, effective April 1, 2023 and 2.18 per cent, effective April 1, 2024;

(ii) Interim and, after certain future determinations in other proceedings, permanent approval of the fiscal 2023, fiscal 2024, and fiscal 2025 Open Access Transmission Tariff (**OATT**) rates as set out in Table 9-4 of the Application, effective April 1, 2022, April 1, 2023 and April 1, 2024, respectively; and

(iii) Set the Deferral Account Rate Rider (**DARR**) on an interim and permanent basis at (2.0) per cent, effective April 1, 2022 for fiscal 2023; and, on a permanent basis at (1.0) per cent, effective April 1, 2023 for fiscal 2024 and (0.5) per cent, effective April 1, 2024, for fiscal 2025.

B. In the Application, BC Hydro also requested that the proposed general and OATT rates remain interim following the BCUC's final decision on this Application, pending the BCUC's determinations in other proceedings regarding an expenditure schedule for demand-side management expenditures for the test period, BC Hydro's cost of capital in fiscal 2024 and fiscal 2025, and, in respect of fiscal 2025, the extent to which Site C Clean Energy Project capital and deferred costs are recoverable from ratepayers;

C. BC Hydro requests that certain information in Chapter 6, Appendix I and Appendix V and all of Appendix JJ be treated as confidential;

…/2

D. BC Hydro requests that all of Chapter 10, Appendix U, Appendix V and Appendix W be treated as confidential until that information is released through a planned public announcement, expected to occur in mid to late September 2021;

E. The BCUC has commenced review of the Application and finds that a regulatory timetable for the review is warranted.

NOW THEREFORE, pursuant to sections 58 to 61 and 90 of the UCA and s. 15 of the ATA, and for the reasons outlined in the decision issued concurrently with this order, the BCUC orders as follows:

1. A hearing is established for the review of the Application in accordance with the regulatory timetable attached as Appendix A to this order (Regulatory Timetable).

2. BC Hydro is to publish the Public Notice, attached as Appendix B to this order, by September X, 2021, in [INSERT] to provide adequate notice to those parties who may have an interest in or be affected by the Application.

3. As soon as practicable, BC Hydro is directed to publish, together with any supporting materials other than those determined to be confidential in this order, the Application, this order and the regulatory timetable by using appropriate communication methods, including BC Hydro's website and social media accounts.

4. Certain information in Chapter 6, Appendix I, Appendix V and all of Appendix JJ will be held confidential unless determined otherwise by the BCUC. All of Chapter 10, Appendix U, Appendix V and Appendix W will be held confidential until the information is released through a planned public announcement, unless determined otherwise by the BCUC. The confidential information, other than that in Appendix JJ, will be made available to registered interveners upon executing the BCUC's form of undertaking, unless determined otherwise by the BCUC.

5. In accordance with BCUC's Rules of Practice and Procedure, parties who wish to actively participate in this proceeding must submit the Request to Intervene Form, available on the BCUC's website at https://www.bcuc.com/get-involved/get-involved-proceeding.html, by the date established in the Regulatory Timetable.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Filepath

British Columbia Hydro and Power Authority
Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

REGULATORY TIMETABLE

Process	Date
Intervener Registration	October 1, 2021
BCUC Information Request No.1 to BC Hydro	October 5, 2021
Intervener Information Request No. 1 to BC Hydro	October 12, 2021
BC Hydro responds to BCUC and Intervener Information Request No. 1	November 18, 2021
BCUC Information Request No.2 to BC Hydro	December 14, 2021
Intervener Information Request No. 2 to BC Hydro	December 21, 2021
BC Hydro responds to BCUC and Intervener Information Request No. 2	February 10, 2022
Intervener Evidence Filed	March 8, 2022
Procedural Conference to decide remainder of process	March 17, 2022
Information Requests on Intervener Evidence	March 31, 2022
Interveners respond to Information Requests	April 21, 2022
BC Hydro files Rebuttal Evidence	May 12, 2022
Further Process	TBD

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

BEFORE:
Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On August 31, 2021, the British Columbia Hydro and Power Authority (BC Hydro) filed its Fiscal 2023 to Fiscal 2025 Revenue Requirements Application (**Application**) with the British Columbia Utilities Commission (**BCUC**) pursuant to sections 58 to 61 and 90 of the *Utilities Commission Act* (**UCA**) and s. 15 of the *Administrative Tribunals Act (***ATA***)*, requesting, among other things:

(i) Interim and, after certain future determinations in other proceedings, permanent approval of an increase in rates by 0.62 per cent, effective April 1, 2022, 0.97 per cent, effective April 1, 2023 and 2.18 per cent, effective April 1, 2024;

(ii) Interim and, after certain future determinations in other proceedings, permanent approval of the fiscal 2023, fiscal 2024, and fiscal 2025 Open Access Transmission Tariff (**OATT**) rates as set out in Table 9-4 of the Application, effective April 1, 2022, April 1, 2023 and April 1, 2024, respectively; and

(iii) Set the Deferral Account Rate Rider (**DARR**) on an interim and permanent basis at (2.0) per cent, effective April 1, 2022 for fiscal 2023; and, on a permanent basis at (1.0) per cent, effective April 1, 2023 for fiscal 2024 and (0.5) per cent, effective April 1, 2024, for fiscal 2025.

B. In the Application, BC Hydro also requested that the proposed general and OATT rates remain interim following the BCUC's final decision on this Application, pending the BCUC's determinations in other proceedings regarding an expenditure schedule for demand-side management expenditures for the test period, BC Hydro's cost of capital in fiscal 2024 and fiscal 2025, and, in respect of fiscal 2025, the extent to which Site C Clean Energy Project capital and deferred costs are recoverable from ratepayers;

C. BC Hydro requests that certain portions of the Application be held confidential in accordance with Part IV of the BCUC's Rules of Practice and Procedure, primarily on the basis that (i) aspects relate to matters deemed

…/2

to be confidential by the BCUC's Rules of Procedure, and (ii) the remainder is security-sensitive information relating to the protection of critical infrastructure, the release of which could compromise the safety and reliability of the Bulk Electric System by exposing it to malicious attacks;

D. By Order No. G-XX-21, the BCUC established the regulatory timetable for the review of the Application; and

E. The BCUC has considered the Application, the evidence, and submissions filed in the proceeding.

NOW THEREFORE, pursuant to sections 58 to 61 and 90 of the UCA and s. 15 of the ATA, and for the reasons outlined in the decision issued concurrently with this order, the BCUC orders as follows:

1. The requested rate increase of 0.62 per cent, 0.97 per cent and 2.18 per cent as applied for in the Application is approved, effective April 1, 2022, April 1, 2023 and April 1, 2024 respectively, but rates will remain interim for the limited purpose of reflecting the BCUC's future determinations regarding:
   (i) An expenditure schedule(s) for demand-side management expenditures for the test period;
   (ii) BC Hydro's cost of capital in fiscal 2024 and fiscal 2025; and
   (iii) The extent to which Site C Clean Energy Project capital and deferred costs are recoverable from ratepayers, in so far as they affect fiscal 2025.

2. The request to set the DARR on a permanent basis at (2.0) per cent, effective April 1, 2022, for fiscal 2023; (1.0) per cent, effective April 1, 2023, for fiscal 2024; and (0.5) per cent, effective April 1, 2024, for fiscal 2025, is approved.

3. The following requests related to deferral and regulatory accounts are approved as follows:
   (i) Load Attraction Costs Regulatory Account

   The request to establish a Load Attraction Costs Regulatory Account to defer actual load attraction operating costs to this account each year beginning in fiscal 2023 and ending in fiscal 2027 is approved. The interest applied to the balance of the account is to be based on BC Hydro's current weighted average cost of debt and the forecast interest charged to the account each year is to be amortized each year. The forecast annual operating cost amount in the account will be amortized into rates starting the fiscal year following the expenditures over the benefit period of 20 years. The forecast balance at the end of a test period related to the difference between the amortization of the forecast annual load attraction operating cost amount and the calculation of the amortization based on the actual annual load attraction operating cost amounts is to be recovered over the next test period. The forecast balance at the end of a test period related to the difference between the forecast interest recovered and the actual interest charged to the account during that test period is recovered over the next test period.

   (ii) MRS Costs Regulatory Account

   The request to defer the following actual unplanned Mandatory Reliability Standards (**MRS**) costs to the MRS Costs Regulatory Account, effective in fiscal 2023 and on an ongoing basis, is approved:

   - Costs related to the implementation of new or revised Standards adopted as a result of a future Assessment Report filed with the BCUC where the BCUC's adoption of such new or revised Standards occurred too late to be reflected in the forecast for the test period; and

- Costs incurred in a test period to address possible non-compliances with MRS, if and as required, where the work related to such possible non-compliances was identified too late to be reflected in the forecast for the test period. This does not include any penalties assessed against BC Hydro.

BC Hydro will recover amounts deferred to the MRS Costs Regulatory Account in respect of completed fiscal years, including any under/over recovered balance from fiscal 2022, over the next test period, starting in fiscal 2026 and on an ongoing basis, subject to BCUC review and approval of these amounts. BC Hydro will apply interest to the balance of the account based on BC Hydro's weighted average cost of debt. BC Hydro will recover actual interest charged to the account for amounts related to any completed fiscal years over the next test period.

(a) Dismantling Cost Regulatory Account

The request to continue to defer any variances between forecast and actual dismantling costs in fiscal 2023 to fiscal 2025 to the Dismantling Cost Regulatory Account is approved. The interest applied to the balance of the account each year is to be based on BC Hydro's current weighted average cost of debt, and the forecast interest charged to the account each year is to be recovered from the account each year. The forecast account balance at the end of a test period is to be recovered over the next test period.

(b) Low Carbon Fuel Credits Account

The request to recover the balance of the Low Carbon Fuel Credits Regulatory Account through the DARR mechanism is approved.

(c) Depreciation Study Impact Regulatory Account

The request to recover the forecast March 31, 2022 balance in the Depreciation Study Impact Regulatory Account for over this test period is approved. BC Hydro will apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt. BC Hydro will recover the forecast interest charged to the account each year beginning in fiscal 2023. BC Hydro will recover any remaining balance at the end of the Test Period, as a result of actual amounts being different than the forecast amount, over the following test period.

(d) Cost of Energy Variance Accounts

The request to recover or refund the balances in the Cost of Energy Variance Accounts through the DARR using the DARR table mechanism as described in Chapter 7, section 7.3.3.3 is approved. Specifically, starting in fiscal 2023 and on an ongoing basis, the DARR percentage effective April 1 of a given year will be set based on the percentage in the DARR table mechanism corresponding to the forecast net balance of the Cost of Energy Variance Accounts at the end of the preceding fiscal year.

(e) Site C Regulatory Account

The request to commence recover the forecast balance in the account as at December 31, 2024 on January 1, 2025 over the forecasted weighted average life of the Site C assets of 84 years is approved. The request to, on an ongoing basis beginning in fiscal 2026, amortize the forecast balance in the Site C Regulatory Account at the end of the prior test period over the remaining weighted average useful life is approved.

(f) Customer Crisis Fund Regulatory Account

The request to recover the forecast March 31, 2022 balance for COVID Relief Fund for Residential Customers in the Customer Crisis Fund Regulatory Account over this test period is approved. The interest applied to the balance of the account in each year is to be based on BC Hydro's current weighted average cost of debt. The forecast interest charged to the account attributable to the COVID Relief Fund for Residential Customers balance each year is to be recovered from the account each year beginning in fiscal 2023.

(g) Mining Customer Payment Plan Regulatory Account

The request to recover the forecast March 31, 2022 balance for COVID-19 Relief measures for commercial customers in the Mining Customer Payment Plan Regulatory Account over this test period is approved. The interest applied to the balance of the account each year is to be based on BC Hydro's current weighted average cost of debt. The forecast interest charged to the account attributable to COVID-19 Relief measures for commercial customers each year is to be recovered from the account each year beginning in fiscal 2023.

(h) Real Property Sales Regulatory Account

The request to continue to defer actual net gains realized on the sale of properties to the Real Property Sales Regulatory Account is approved. The interest applied to the balance of the account will continue to be based on BC Hydro's current weighted average cost of debt. If an amount is owing to ratepayers at the end of the test period, the balance in the account is to be refunded to ratepayers over the next test period. If an amount is recoverable from ratepayers at the end of the Test Period, the balance in the account is to be recovered from ratepayers over the next test period.

(i) Electric Vehicle Costs Regulatory Account

The request to recover the forecast March 31, 2022 balance for the Electric Vehicle Costs Regulatory Account over this test period and recover any balance remaining at the end of this test period over the next test period is approved. The interest applied to the balance of the account each year is to be based on BC Hydro's current weighted average cost of debt. The forecast interest charged to the account each year is to be recovered from the account each year beginning in fiscal 2023.

(j) DSM Regulatory Account

The request to not change the recovery of the Low Carbon Electrification Component of the DSM Regulatory Account is approved.

4. With respect to depreciation rates:

(i) The request to implement for ratemaking purposes the updated useful lives and positive salvage rates and changes in asset classes, effective fiscal 2022, as set out in Chapter 8, section 8.3, is approved.

(ii) The request to implement for ratemaking purposes the net salvage rates beginning in the next test period, using a phased-in approach, as set out in Chapter 8, section 8.4, is approved.

5. The requested OATT rates as set out in Appendix II, Table II-2 of the Application are approved, effective April 1, 2022, April 1, 2023 and April 1, 2024, respectively, but rates will remain interim for the limited purpose of reflecting the BCUC's determinations regarding the items identified in paragraph 1.

6. Within 30 days of the date of this Order, BC Hydro is to file the applicable Tariff sheets reflecting the approved general and OATT rates for fiscal 2023.

7. The request to hold certain information in Chapter 6, Appendix I and Appendix V and all of Appendix JJ confidential is granted.

8. BC Hydro is directed to comply with all other directives contained in the decision issued concurrently with this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment Options

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix C

Government Mandate Letter and
BC Hydro Service Plan

BRITISH
COLUMBIA

June 15, 2021

Mr. Doug Allen
Chair
BC Hydro
18th Floor, 333 Dunsmuir Street
Vancouver, BC V6B 5R3

Dear Mr. Allen:

On behalf of Premier John Horgan and the Executive Council, I would like to extend my thanks to you and your board members for the dedication, expertise and skills with which you serve the people of British Columbia.

Every public sector organization is accountable to the citizens of British Columbia. The expectations of British Columbians are identified through their elected representatives, the members of the Legislative Assembly. Your contributions advance and protect the public interest of all British Columbians and, through your work, you are supporting a society in which the people of this Province can exercise their democratic rights, trust and feel protected by their public institutions.

You are serving British Columbians at a time when people in our province face significant challenges as a result of the global COVID-19 pandemic. Recovering from the pandemic will require focused direction, strong alignment and ongoing engagement between public sector organizations and government. It will require all Crowns to adapt to changing circumstances and follow Public Health orders and guidelines as you find ways to deliver your services to citizens.

This mandate letter, which I am sending in my capacity as Minister responsible for BC Hydro on behalf of the Executive Council, communicates expectations for your organization. It sets out overarching principles relevant to the entire public sector and provides specific direction to BC Hydro about priorities and expectations for the coming fiscal year.

I expect that the following five foundational principles will inform your agency's policies and programs:

Ministry of
Energy, Mines and
Low Carbon Innovation

Office of the Minister

Mailing Address:
PO Box 9060, Stn Prov Govt
Victoria, BC V8W 9E2

Telephone: 250 953-0900

- **Putting people first:** We are committed to working with you to put people first. You and your board are uniquely positioned to advance and protect the public interest, and I expect that you will consider how your board's decisions maintain, protect and enhance the public services people rely on and make life more affordable for everyone.

- **Lasting and meaningful reconciliation:** Reconciliation is an ongoing process and a shared responsibility for us all. Government's unanimous passage of the *Declaration of the Rights of Indigenous Peoples Act* was a significant step forward in this journey – one that all Crown agencies are expected to support as we work in cooperation with Indigenous peoples to establish a clear and sustainable path to lasting reconciliation. True reconciliation will take time and ongoing commitment to work with Indigenous peoples as they move towards self-determination. Guiding these efforts, Crown agencies must also remain focused on creating opportunities that implement the Truth and Reconciliation Commission's recommendations through your mandate.

- **Equity and anti-racism:** Our Province's history, identity and strength are rooted in its diverse population. Yet racialized and marginalized people face historic and present-day barriers that limit their full participation in their communities, workplaces, government and their lives. The public sector has a moral and ethical responsibility to tackle systemic discrimination in all its forms – and every public sector organization has a role in this work. All Crowns are expected to adopt the Gender-Based Analysis Plus (GBA+) lens to ensure equity is reflected in your operations and programs. Similarly, appointments resulting in strong public sector boards that reflect the diversity of BC will help achieve effective and citizen-centred governance.

- **A better future through fighting climate change:** Announced in December 2018, the CleanBC climate action plan puts our Province on the path to a cleaner, better future by building a low-carbon economy with new clean energy jobs and opportunities, protecting our clean air, land and water and supporting communities to prepare for carbon impacts. As part of the accountability framework established in CleanBC, and consistent with the *Climate Change Accountability Act*, please ensure your organization aligns operations with targets and strategies for minimizing greenhouse gas emissions and managing climate change risk, including the CleanBC target of a 50% reduction in public sector building emissions and a 40% reduction in public sector fleet emissions by 2030. Your organization is expected to work with government to report out on these plans and activities as required by legislation.

- **A strong, sustainable economy that works for everyone:** I expect that you will identify new and flexible ways to achieve your mandate and serve the citizens of BC within the guidelines established by the Provincial Health Officer and considering best practices for conducting business during the pandemic. Collectively, our public sector will continue to support British Columbians through the pandemic and economic recovery by investing in health care, getting people back to work, helping businesses and communities, and building the clean, innovative economy of the future. As a public sector organization, I expect that you will consider how your decisions and operations reflect environmental, social and governance factors and contribute to this future.

The Crown agencies and Board Resourcing Office (CABRO), with the Ministry of Finance, will continue to support you and your board on recruitment and appointments as needed, and will be expanding professional development opportunities in 2021/22. The Governing in the Public Interest online certificate program is now available, and all board members are encouraged to complete this new offering.

As the Minister Responsible for BC Hydro, I expect that you will make substantive progress on the following priorities and incorporate them in the goals, objectives and performance measures in your 2021/22 Service Plan:

- Provide leadership in advancing CleanBC’s climate and economic development objectives, including electrification, fuel switching, and energy efficiency initiatives in the built environment, transportation, mining, oil and gas, and other sectors.

- Keep electricity affordable by ensuring that rates do not increase above inflation, on a cumulative basis, over the next decade.

- Continue delivering affordability measures that support BC’s Poverty Reduction Strategy, including demand-side management programs targeted to low-income customers, in a manner consistent with new and emerging CleanBC policies.

- Maintain or improve customer satisfaction by providing timely and responsive service.

- Safely complete the Site C project within the lowest cost and approved schedule, and implement the recommendations of the Milburn Report, reports from independent dam safety experts, other directions from the Minister responsible, and provide quarterly progress and other reporting to Treasury Board and the BC Utilities Commission.

- Continue to implement government direction resulting from the Comprehensive Review of BC Hydro. Priority initiatives for 2021/22 should include:

- Supporting the implementation of the BC Hydrogen Strategy;
- Expanding BC Hydro's network of electric vehicle DC fast-charging stations;
- Supporting clean technology innovation through Powertech;
- Increasing industrial electrification by making it easier and faster for customers to connect to the electricity grid; and
- Re-investing new low carbon fuel standard credit revenues in transportation electrification infrastructure, incentives and programs.

- Develop a short-term electrification plan that builds on the key results of the Comprehensive Review of BC Hydro and supports CleanBC.

- Working with customers, develop efficient and flexible rate proposals for BC Utilities Commission review that will incent greenhouse gas emission reductions and keep rates affordable.

- Actively market 100% clean energy through Powerex to realize new trading opportunities and income for the benefit of BC Hydro ratepayers.

- Partner with the Province and the federal government to implement the CleanBC Remote Community Energy Strategy to help remote communities, with a focus on Indigenous communities, reduce diesel use and replace it with clean energy.

- Work with the Province to secure additional federal funding and bring into service transmission projects that will reduce or avoid greenhouse gas emissions and help meet its climate goals.

Each board member is required to sign the Mandate Letter to acknowledge government's direction to your organization. The signed Mandate Letter is to be posted publicly on your organization's website in spring 2021.

I look forward to continuing to work with you and your Board colleagues to build a better BC.

Sincerely,

Bruce Ralston
Minister

Date: June 15, 2021

Doug Allen, Chair	Len Boggio, Director	Daryl Fields, Director	Valerie Lambert, Director
Irene Lanzinger, Director	Nalaine Morin, Director	John Nunn, Director	Catherine Roome, Director
Chris Sanderson, Director			

cc: Honourable John Horgan, Premier
Lori Wanamaker, Deputy Minister to the Premier, Cabinet Secretary and Head of the BC Public Service
Heather Wood, Deputy Minister and Secretary to Treasury Board, Ministry of Finance
Douglas S. Scott, Deputy Minister, Crown Agencies Secretariat, Ministry of Finance
Fazil Mihlar, Deputy Minister, Ministry of Energy, Mines and Low Carbon Innovation
Len Boggio, Director, BC Hydro
Daryl Fields, Director, BC Hydro
Valerie Lambert, Director, BC Hydro
Irene Lanzinger, Director, BC Hydro
Nalaine Morin, Director, BC Hydro
John Nunn, Director, BC Hydro
Catherine Roome, Director, BC Hydro
Chris Sanderson, Director, BC Hydro
Chris O'Riley, President and Chief Executive Officer, BC Hydro

BC Hydro and Power Authority

2021/22 – 2023/24
Service Plan

April 2021

For more information on BC Hydro contact:

333 Dunsmuir Street

Vancouver, BC

V6B 5R3

Lower Mainland

604 BCHYDRO

(604 224 9376)

Outside Lower Mainland

1 800 BCHYDRO

(1 800 224 9376)]

Or visit our website at

bchydro.com

Published by BC Hydro

Board Chair's Accountability Statement

The 2021/22 – 2023/24 BC Hydro Service Plan was prepared under the Board's direction in accordance with the *Budget Transparency and Accountability Act*. The plan is consistent with government's strategic priorities and fiscal plan. The Board is accountable for the contents of the plan, including what has been included in the plan and how it has been reported. The Board is responsible for the validity and reliability of the information included in the plan.

All significant assumptions, policy decisions, events and identified risks, as of February 28, 2021 have been considered in preparing the plan. The performance measures presented are consistent with the *Budget Transparency and Accountability Act*, BC Hydro's mandate and goals, and focus on aspects critical to the organization's performance. The targets in this plan have been determined based on an assessment of BC Hydro's operating environment, forecast conditions, risk assessment and past performance.

Doug Allen
Board Chair

Table of Contents

Strategic Direction and Alignment with Government Priorities

In 2021/22, British Columbians continue to face significant challenges as a result of the global COVID-19 pandemic. Recovering from the pandemic will require focused direction, strong alignment and ongoing engagement between public sector organizations and the Government of British Columbia. The government has identified five foundational principles that will inform each Crown agency's policies and programs and contribute to COVID recovery: putting people first, lasting and meaningful reconciliation, equity and anti-racism, a better future through fighting climate change and meeting our greenhouse gas commitments, and a strong, sustainable economy that works for everyone.

BC Hydro is one of the largest electric utilities in Canada and is publicly owned by the people of British Columbia. We generate and provide electricity to 95 percent of B.C.'s population and serve over four million people. The electricity we generate and deliver to customers throughout the province powers our economy and quality of life.

As a provincial Crown Corporation, BC Hydro reports to the Provincial Government through the Minister of Energy, Mines and Low Carbon Innovation. Government's expectations are expressed through the following legislation and policy:

- The *Hydro and Power Authority Act*
- The *Utilities Commission Act*
- The *BC Hydro Public Power Legacy and Heritage Contract Act*
- The *Clean Energy Act* (CEA)
- CleanBC

Our mission is: we are here to safely provide our customers with reliable, affordable, clean electricity. We have set out a three-year plan with strategies, performance measures and targets, aligned with the priorities in the B.C. Government's Mandate Letter to BC Hydro, to fulfill our mission on behalf of our customers and the Province.

Climate change, technological advances and evolving customer energy needs continue to transform our business. While we navigate these ongoing developments, we have the important responsibility of keeping electricity rates affordable for our customers and funding necessary investments in our system to ensure British Columbians continue to receive reliable and clean electricity.

We are implementing the outcomes from the Comprehensive Review of BC Hydro to strategically position BC Hydro for long-term success, while meeting the Province's climate goals and keeping rates affordable for British Columbians. To help advance the Province's CleanBC climate and economic development objectives, we are encouraging our customers to use our clean and reliable electricity to power their homes, vehicles and businesses in order to reduce greenhouse gas (GHG) emissions. We are also advancing affordability initiatives to help our customers save money on their electricity bills and continuing to focus on making it easier for our customers to do business with us.

To ensure sustained economic and social benefits for customers, we manage our capital portfolio with an emphasis on cost consciousness, respect for the environment and communities in which we work, and in particular, strengthening our relationships with Indigenous communities.

BC Hydro will continue making investments to expand and maintain the system to meet our customers' growing needs and expectations, while managing our costs, helping keep electricity bills affordable for our customers and improving our service.

Operating Environment

As a utility that operates in a high hazard industry, we are committed to ensuring our workforce goes home safely every day and that the public is safe around our system. We are continuously working to improve our performance by implementing integrated safety and compliance framework and programs.

The COVID-19 pandemic has presented unprecedented challenges for BC Hydro and our customers. However, it has also made our role as an essential service, providing clean, reliable and affordable electricity to our customers more important than ever. As a Crown Corporation, we will continue to support the Province and our customers to help B.C.'s economy recover from the effects of COVID-19.

BC Hydro will continue to address the considerable challenges of the Site C project to allow us to continue to provide the clean, reliable and affordable electricity that is vital to British Columbia's economic prosperity. Prior to the onset of COVID-19, BC Hydro had identified that the project was facing significant cost pressures that were being assessed, monitored and managed to the best extent possible. The COVID-19 pandemic, along with the need for foundation enhancements on the right bank to contend with unanticipated geotechnical conditions, added further significant cost and schedule pressures.

On February 26, 2021, the Province of B.C. announced an updated cost estimate for the Site C project of $16 billion. This includes a new expected in-service date of 2025, a one-year delay due to COVID-19. The Province also released the independent review of the project by Peter Milburn, with 17 recommendations aimed at improving oversight and governance. The Province and BC Hydro accepted all recommendations and will work to implement them in order to safely complete the Site C project.

BC Hydro is regulated by the British Columbia Utilities Commission (BCUC). As the independent regulator of BC Hydro, the BCUC reviews BC Hydro's costs, proposed rate increases, integrated resource planning and almost all regulatory accounts, programs and capital projects. On December 22, 2020, BC Hydro submitted the Fiscal 2022 Revenue Requirements Application to the BCUC and in 2021/22, we will prepare a comprehensive Revenue Requirements Application for Fiscal 2023 onwards. These applications reflect our efforts to continue to deliver safe and reliable power, while keeping electricity affordable for our customers.

We are developing an Integrated Resource Plan that will outline how BC Hydro is preparing for the evolving energy landscape that includes climate goals, technological advances, changing customer preferences and market conditions. The plan, which will be filed with the BCUC this year, will include electrification scenarios to show how BC Hydro will leverage our clean electricity to support the Province's CleanBC plan to transform and electrify British Columbia's economy. BC Hydro is also developing new measures to monitor our progress in supporting the plan.

The electricity we generate and deliver throughout B.C. meets a high standard of reliability, but we are always looking for ways to improve our service to our customers and help power British Columbia's strong, sustainable economy. We are continuing to build our resilience against cyber and physical attacks on our system to continue to safely provide reliable electricity to our customers.

BC Hydro is focused on delivering our renewed customer service strategy, with the goal of making it easier to do business with us and helping customers make smart energy choices through our conservation and energy management programs. Part of this focus includes working to understand the evolving needs of our customers and how they use the electricity we provide. We will also continue to advance affordability initiatives to help our customers save money on their electricity bills. To help advance the Province's CleanBC climate and economic development objectives, we are encouraging our customers to use our clean and reliable electricity to power their homes, vehicles and businesses in order to reduce GHG emissions.

We continue to make significant investments to expand the system and maintain aging infrastructure, while prudently managing all costs to help keep electricity affordable for our customers. We work across teams, suppliers and experts to ensure thoughtful assessment of how to successfully deliver these projects on time and on budget while respecting the unique community, environmental and Indigenous interests associated with each project.

Operating, maintaining and expanding BC Hydro's extensive electricity system impacts a significant number of Indigenous communities across the province. We continue to pursue meaningful, long-term relationships with Indigenous groups to better understand their interests, so they can be incorporated in our planning and business operations. With the historic passing of the *Declaration on the Rights of Indigenous Peoples Act* in November 2019, BC Hydro is working to implement the United Nations Declaration on the Rights of Indigenous Peoples, the Calls to Action of the Truth and Reconciliation Commission and the Draft Principles that Guide the Province of British Columbia's Relationship with Indigenous Peoples into our business.

With thoughtful planning and prudent decision-making, BC Hydro is well positioned to safely provide reliable, affordable, clean electricity throughout B.C., today and into the future.

Performance Planning

Goal 1: Safety Above All

Objective 1.1: Safety at BC Hydro is a core value. We are committed to ensuring our workforce goes home safely every day, and that the public is safe around our system.

Key Strategies

- Form a strong partnership with operational teams to guide and assist them in creating and sustaining a safe work place.
- Implement an integrated and sustainable safety and compliance framework with defined governance, processes, accountabilities and responsibilities to manage risk.
- Support a learning culture within BC Hydro by using incident and near miss data and investigation learnings to inform improvements in job planning, work methods, training and other elements of our safety framework.
- Continue to standardize and consolidate safety information in one location so employees can easily find and understand rules, procedures and work methods they require to complete their work.
- Continue public education efforts on hazards associated with electricity.
- Protect the public from hazards around our reservoirs and dams through adherence to the Canadian Dam Association Public Safety Around Dams guidelines.
- Develop safety analytic and reporting services that will assist the organization to turn data into actionable information that improves safety outcomes.

Performance Measure(s)[1]	2020/21 Forecast	2021/22 Target	2022/23 Target	2023/24 Target
1.a Zero Fatality & Serious Disabling Injury[2] [Loss of life or the injury has resulted in a permanent disability]	0	0	0	0
1.b Lost Time Injury Frequency [Number of employee injury incidents resulting in lost time (beyond the day of the injury) per 200,000 hours worked]	0.70	0.76	0.74	0.74
1.c Timely Completion of Corrective Actions (%)	97	97	98	98

[1] Performance Measure descriptions, rationale, data source information and benchmarking are available online at www.bchydro.com/performance
[2] Zero Fatality and Serious Disabling Injury – BC Hydro's safety performance measures do not include contractor or public safety injuries or fatalities.

Linking Performance Measure to Objective

1.a Achieving our target of Zero Fatality and Serious Disabling Injury supports our objective that everyone goes home safely, every day.

1.b Lost Time Injury Frequency (LTIF) is an indicator of the likelihood of a full-time employee sustaining a time loss injury in a normal work year and is a comparable metric to other provincial organizations and the Canadian Electricity Association. LTIF of 1 equates to a 1 per cent chance of a time loss injury for any given employee in a work year.

1.c Timely Completion of Corrective Actions supports our strategy towards becoming a learning organization by addressing systemic improvements to our business to manage risk in a timely manner.

Discussion

BC Hydro forecasts that it will achieve its LTIF 2020/21 target largely due to a continued focus on job planning and ergonomics, as most of our lost time injuries result from body mechanic injuries. The 2022/23 target has been reduced by 2.0 percent, while the 2023/24 target has been set to sustain future performance.

Our Timely Completion of Corrective Actions targets focus on meeting the due dates of these actions. Results are reported using the definition of the measure introduced in the 2018/19 – 2020/21 Service Plan: the percentage of safety corrective actions closed on or before the scheduled due date on an annual basis. The 2021/22 and 2022/23 targets sustain our current performance, which supports regulatory reporting requirements and our goal to learn from safety incident data.

Goal 2: Set the Standard for Reliable and Responsive Service

Objective 2.1: BC Hydro will reliably meet the evolving expectations of our customers by prudently planning and investing in the system, improving our service and advancing reconciliation with Indigenous Peoples.

This objective has been updated using more concise language to ensure alignment with Goal 2.

Key Strategies

- Ensure the reliability and resilience of the generation, transmission and distribution system by effectively implementing capital, maintenance and vegetation programs to manage the overall condition of the power system and ensure supply to meet customer load.
- Safeguard the system with risk-prioritized security solutions and prepare our operations with well-practiced emergency response plans to support system reliability and resilience.
- Continue to make it easier for customers to do business with us through a series of customer facing improvements such as: exploring new contact centre technologies, engaging customers in our rate design and project planning processes; exploring new rate proposals to meet our customers' needs; and incorporating the Gender Based Analysis Plus lens to broaden our understanding of how policies and practices impact our customers.
- Sustain gold-level certification under the Progressive Aboriginal Relations program by successfully preparing and presenting BC Hydro's 2021 Progressive Aboriginal Relations Certification submission and clearly demonstrating the corporation's continuous improvement in advancing practices in the areas of leadership, employment, business development and community relationships.
- Continue to advance reconciliation by incorporating the United Nations *Declaration on the Rights of Indigenous Peoples Act*, the Calls to Action of the Truth and Reconciliation Commission and the Draft Principles that Guide the Province of British Columbia's Relationship with Indigenous Peoples into our business.

Performance Measure(s)[1]	2020/21 Forecast	2021/22 Target	2022/23 Target	2023/24 Target
2.a SAIDI (System Average Interruption Duration Index)[2] [Total outage duration (in hours) of sustained interruptions experienced by an average customer in a year (excluding major events)]	3.09	3.20	3.17	3.17
2.b SAIFI (System Average Interruption Frequency Index)[2] [Total number of sustained interruptions experienced by an average customer in a year (excluding major events)]	1.41	1.40	1.38	1.38
2.c Key Generating Facility Forced Outage Factor (%)	1.25	1.80	1.80	1.80
2.d CSAT Index[3] [Customer Satisfaction Index: % of customers satisfied or very satisfied]	91	85	85	85
2.e Progressive Aboriginal Relations Certification[4]	Gold	Gold	Gold	Gold

[1] Performance Measure descriptions, rationale, data source information and benchmarking are available online at www.bchydro.com/performance
[2] Reliability targets are based on specific values, however performance within 10 per cent is considered acceptable given the reliability projection modelling uncertainty, the wide range of variations in weather patterns and the uncontrollable elements that can significantly disrupt the electrical system. BC Hydro reports reliability under normal circumstances, because major events are not predictable and largely uncontrollable. The reliability measure is therefore based on data that excludes major events. BC Hydro reviews performance during major events and takes the performance into consideration in reliability improvement initiatives.
[3] Customer Satisfaction Index (CSAT) is an index measuring customer satisfaction of BC Hydro's three main customer groups (residential, commercial and key accounts). The index is comprised of the five key drivers of satisfaction weighted equally across the three customer types.
[4] Progressive Aboriginal Relations is a certification program by the Canadian Council of Aboriginal Business. It is reviewed on a three-year cycle.

Linking Performance Measure to Objective

2.a &b Customer reliability is measured using the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). These, along with correlated cause analysis for customer outages, support targeted investment, planning and process improvements to meet our customers' needs for reliability.

By measuring the average number of service interruptions and number of hours of sustained interruptions experienced by the average customer in a year, we are able to track our ability to reliably meet the electricity requirements of customers.

2.c A forced outage occurs when a generating unit is unable to start generating or does not stay in service when needed. The Key Generating Facility Forced Outage Factor shows the trend of how the generation assets are performing and supports investment decisions to maintain asset reliability.

2.d The Customer Satisfaction (CSAT) Index measures customer satisfaction with BC Hydro on five key drivers: value for money; commitment to customer service; providing reliable electricity; acting in the best interest of British Columbians; and efforts to communicate to customers and communities. This measure gauges the degree to which BC Hydro is meeting customers' electricity and service needs.

2.e The Canadian Council of Aboriginal Business's Progressive Aboriginal Relations (PAR) Gold certification offers validation of BC Hydro's continuous improvement and focus on enhanced Indigenous relations. With BC Hydro's extensive footprint throughout the province, and our role as a Crown corporation, the comprehensiveness of the PAR certification acts as a measure for us to ensure our policies and practices across the company appropriately reflect Indigenous interests and our employees understand the importance of building and maintaining strong relationships with Indigenous Peoples.

Discussion

SAIDI and SAIFI targets are based on several factors including long-term historic reliability trending, current year performance, previous years' investments and future years' investment plans, while also accounting for annual variability due to weather. Consistent focus on customer reliability has continued to enable the 2021/22 targets to remain stable and to improve in 2022/23 to align with historical performance, planned investment, ongoing process improvements and expected benefits from planned increased investment in transmission and distribution vegetation programs.

There are seven Key Generating Facilities, representing those plants with installed capacity greater than 200 megawatts (MW). Together, they provide over 90 percent of the average annual electricity generated by BC Hydro's facilities. Key Generating Facility Forced Outage Factor is reported as a five-year rolling average and defined as the total forced outage time in a period relative to the total number of hours in the same period (usually one year). Annually, the Forced Outage Factor can be relatively volatile, and applying the historical five-year rolling average smooths the range to provide a more stable measure for which targets can be set. The objective is to keep the Forced Outage Factor below 1.80 percent of the total number of hours per year, which demonstrates the effectiveness of BC Hydro's maintenance and capital investment programs.

BC Hydro's CSAT 2020/21 forecast result reflects our responses to the COVID-19 pandemic, which included providing payment assistance to residential, small business and industrial customers. In 2021/2022 - 2023/2024, we will work to meet a CSAT index of 85.0 by consistently improving customer experience and meeting customers' growing expectations based on their interactions with other organizations.

The Canadian Council of Aboriginal Business' PAR is a certification program designed to help Canadian businesses benchmark, improve and signal their commitment to progressive relationships with Indigenous communities, businesses and people. It evaluates four areas of performance including: leadership actions; employment; business development; and community relations. PAR certification provides a high degree of assurance to Indigenous communities, as certification every three years is supported by an independent third-party verification and is determined by a jury comprised of Indigenous business people. BC Hydro has attained the highest, gold-level designation from the Canadian Council for Aboriginal Business since 2012. In 2021/22, BC Hydro will apply for the next certification and seek to sustain our gold level certification.

Goal 3: Help Keep Electricity Bills Affordable for our Customers

Objective 3.1: BC Hydro will help keep electricity bills affordable by managing our costs, exploring innovative solutions to support our customers and making cost-effective investments to maintain and expand our electricity system.

Key Strategies

- Working with the Province, continue delivering affordability measures, including demand-side management programs targeted to low-income households, to help our customers manage their electricity bills.
- Advance efficient and flexible rate proposals with the BCUC to help keep customers' electricity bills affordable.
- Submit Revenue Requirements Applications to the BCUC consistent with the goal of achieving rate increases that are less than the provincial rate of inflation, on a cumulative basis, for the period of Fiscal 2021 to Fiscal 2030.
- Make all reasonable efforts to keep rates affordable by implementing the outcomes of Phase 1 of the Comprehensive Review, including strategies to reduce future energy procurement costs.
- Implement recommendations of Phase 2 of the Comprehensive Review, to improve affordability of electricity, enable clean technological innovation, reduce GHG emissions through electrification, and advance reconciliation with Indigenous Peoples.
- Safely complete the Site C project within lowest practicable cost by the new expected in-service date of 2025. This includes work to:
    - Implement foundation enhancement measures to address geotechnical issues on the project's right bank.
    - Implement the recommendations of the independent consultant (Milburn) report, which include enhancing the independence, mandate and expertise of the Site C Project Assurance Board and strengthening BC Hydro's risk reporting and management.
    - Provide quarterly progress and exception reporting to Treasury Board.
- Implement our 10 Year Capital Plan so that our customers can continue to receive clean, reliable and affordable electricity.
- Continue to refine and enhance our systematic and disciplined project delivery methodology to ensure that our projects are put into service safely, on time, on budget and to a high standard of quality.
- Achieve benefits of improved procurement and supply chain management practices and tools.

Performance Measure(s)[1]	2020/21 Forecast	2021/22 Target	2022/23 Target	2023/24 Target
3.a Affordable Bills – Residential[2]	1st quartile	1st quartile	1st quartile	1st quartile
3.b Affordable Bills – Commercial[2]	1st quartile	1st quartile	1st quartile	1st quartile
3.c Affordable Bills – Industrial[3]	1st quartile	1st quartile	1st quartile	1st quartile
3.d Project Budget to Actual Cost[4]	-4.09% on $4.07 billion[5]	Within+5% to -5% of budget excluding project reserve amounts	Within+5% to -5% of budget excluding project reserve amounts	Within+5% to -5% of budget excluding project reserve amounts

[1] Performance Measure descriptions, rationale, data source information and benchmarking are available online at www.bchydro.com/performance

[2] As of 2020/21, BC Hydro calculates the Affordable Bills performance measure for residential and commercial customers as the median consumption level for residential and commercial customer classes compared to the equivalent power consumption sub-category from Hydro Quebec's annual report on North American electricity rates. The rankings of the 22 participating utilities are then allocated into quartiles. The 1st quartile ranking represents the six utilities that have the lowest monthly electricity bills on April 1 of a given year.

[3] BC Hydro measures affordability within the industrial category based on the largest consumption level from Hydro Quebec's annual report on North American electricity rates.

[4] This measure compares actual project costs at completion to the original approved expected cost budget for the project, not including project reserve amounts, for capital projects that were put into service during the five-year rolling period.

[5] This represents projects that went or are forecasted to go into service for the five-year period of 2016/17 to 2020/21.

Linking Performance Measure to Objective

3.a, b & c The Affordable Bills measures are based on BC Hydro's rankings in the residential, commercial, and transmission service rate categories in the annual Hydro Quebec report, Comparison of Electricity Prices in Major North American Cities. The report is used as a benchmark to demonstrate that our bills are affordable compared to other major North American utilities.

3.d Since 2015/16, BC Hydro has utilized the Project Budget to Actual Cost measure for the delivery of capital projects, with a target of actual project costs to be within +5 percent to -5 percent of the budget, excluding project reserves at the portfolio level. The +/- 5 percent target is the same over the plan period, as it is the objective to have the entire project portfolio in-service within this actual cost range. BC Hydro has consistently met this performance target, as we continue to prudently manage capital expenditures and keep rates affordable for our customers.

Discussion

The Affordable Bills measure was previously based on residential customers only and was calculated by averaging BC Hydro's ranking across multiple residential sub-categories, as reported in Hydro Quebec's annual report on North American electricity rates. While affordability in the residential rates category is important, we recognize that it is also important to our other customer classes and this measure has now been expanded to include commercial and industrial customers. The methodology for calculating these performance measures uses the median consumption level for the residential and commercial performance measures and the largest consumption level for the industrial performance measure. Median consumption level provides a better representation of the central tendency than average and the largest consumption level provides the best indication of BC Hydro's performance regarding rate competitiveness for large industrial customers.

The Project Budget to Actual Cost measure includes Dam Safety, Generation, Transmission Line, Substation and large Distribution projects, managed by BC Hydro Capital Infrastructure Project Delivery and Properties for the last five years. Annually, BC Hydro reports the past five years' performance at the portfolio level in delivering capital projects.

Goal 4: Help Make Renewable, Clean Power British Columbia's Leading Energy Source

Objective 4.1: BC Hydro will encourage the use of its renewable, clean power for electrification to reduce greenhouse gas emissions and will continue to invest in its energy-efficiency and conservation programs.

This objective was restated to highlight importance of electrification.

Key Strategies

- Support the implementation of the CleanBC plan to increase British Columbians' use of clean energy in transportation, buildings and industry by advancing an electrification plan and related performance measures.
- Support customers with initiatives and rate structures that help them make smart energy choices through our energy management (e.g. energy efficiency and conservation programs) and low carbon electrification initiatives.
- Provide customers with the opportunity to more easily access clean, renewable power to displace the use of higher carbon energy sources.
- As part of the CleanBC plan, partner with the Province and the federal government to help remote communities, with a focus on Indigenous communities, reduce or eliminate diesel generation and replace it with energy from cleaner sources.

Performance Measure(s)[1]	2020/21 Forecast	2021/22 Target	2022/23 Target	2023/24 Target
4.a Energy Conservation Portfolio (New incremental GWh/year)[2]	765	500	500	500
4.b Clean Energy (%)	98.0	93.0	93.0	93.0

[1] Performance Measure descriptions, rationale, data source information and benchmarking are available online at www.bchydro.com/performance
[2] BC Hydro's future Energy Conservation Portfolio targets will be informed by the next Integrated Resource Plan, filed with the BCUC.

Linking Performance Measure to Objective

4.a The Energy Conservation Portfolio performance measure reflects new incremental energy savings from programs, codes and standards and conservation rates. This measures the success of BC Hydro's planned conservation targets. Targets are rounded values and considered to be achieved if performance is within 10 percent of the stated values.

4.b The Clean Energy performance measure demonstrates BC Hydro's efforts to generate clean, sustainable, affordable electricity in order to reduce GHG emissions in the province and continue to meet the 93 percent minimum clean energy objective in the *Clean Energy Act*. The higher the percent clean energy that BC Hydro achieves, the lower the GHG emissions in the province.

Discussion

The targets for Energy Conservation Portfolio are based on BC Hydro's forecast of annual new incremental energy savings and do not reflect past performance and/or adjustments made to energy savings in prior years (e.g., persistence, evaluations, measurement and verification). In some cases, the timing of savings for anticipated codes and standards and timing of large customer projects can shift, which will cause actual incremental energy savings to vary from the targets that have been set for the period.

The Clean Energy performance measure represents the minimum threshold generation output in accordance with the B.C. Government's requirement that at least 93 percent of electricity generation in the province be from clean or renewable resources, as specified in the *Clean Energy Act.* While actual output of the non-clean resources in the system supports system reliability and can vary depending on market conditions and water inflows to our reservoirs, BC Hydro expects that the actual performance will remain close to 98 percent.

Financial Plan

Summary Financial Outlook

Consolidated Statement of Operations[1] ($ millions)	2020/21 Forecast	2021/22 Budget	2022/23 Budget	2023/24 Budget
Domestic	5,191	5,527	5,641	5,765
Trade	1,080	1,121	984	949
Total Revenues	**6,271**	**6,648**	**6,624**	**6,714**
Operating Costs				
Cost of energy	2,231	2,389	2,460	2,494
Personnel expenses, materials & external services[2]	1,236	1,317	1,332	1,364
Amortization	1,006	1,033	1,022	1,041
Grants and taxes	265	274	286	302
Finance charges	838	552	480	435
Other	198	101	120	111
Total Expenses	**5,775**	**5,667**	**5,700**	**5,747**
Net Income before movement in regulatory balances	497	981	924	967
Net movement in regulatory balances	194	(269)	(212)	(255)
Net Income	**691**	**712**	**712**	**712**
Other Selected Financial Information:				
Dividends	**-**	**-**	**-**	**-**
Net Debt[3]	**25,338**	**28,115**	**30,590**	**31,819**
Equity	**6,346**	**7,058**	**7,770**	**8,482**
Capital Expenditures	**3,573**	**4,738**	**4,413**	**3,305**

[1] Table may not add due to rounding.
[2] These amounts are net of capitalized overhead and consist of the following:

	2020/21	2021/22	2022/23	2023/24
Domestic Base Operating Costs	833	905	918	937
Other	403	412	415	427
	1,236	1,317	1,332	1,364

Other largely consists of Powerex & Powertech operating costs, IFRS-ineligible capital overhead phased into operating costs over a 10-year period ending in 2020/21, and expenses subject to regulatory deferral.
[3] Debt figures are net of sinking funds and cash and cash equivalents.

Key Forecast Assumptions, Risks and Sensitivities

Key Assumptions	2020/21 Forecast	2021/22 Budget	2022/23 Budget	2023/24 Budget
Growth and Load				
B.C. Real Gross Domestic Product Growth (%)[1]	(6.7)	3.0	3.8	2.7
Domestic Sales Load Growth (%)[2, 3]	(2.46)	3.54	1.54	2.43
Load and System Exports:				
Domestic Sales Volume (GWh)	50,655	52,448	53,258	54,552
System Exports Volume (GWh)	9,220	6,979	5,893	4,827
Line Loss and System Use (GWh)	4,947	5,376	5,417	5,509
Total Load and System Exports (GWh)	64,821	64,802	64,568	64,887
Energy Generation				
Total System Water Inflows (% of average)	110	100	100	100
Sources of Supply:				
Hydro Generation (GWh)	48,807	46,718	45,635	45,253
System Imports (GWh)	1,257	1,836	2,588	3,291
Independent Power Producers and Long-term Purchases (GWh)	14,502	15,970	16,059	16,036
Thermal Generation & Other (GWh)	255	278	287	307
Sources of Supply (GWh)	64,821	64,802	64,568	64,887
Average Mid-C Price (U.S.$/MWh)	27.87	30.83	29.78	28.67
Average Natural Gas Price at Sumas (U.S.$/MMBTU)	3.11	3.08	2.61	2.46
Financial				
Canadian Short-Term Interest Rates (%)[4]	0.24	0.24	0.30	0.60
Canadian Long-Term Interest Rates (%)[4]	1.49	1.86	2.12	2.37
Foreign Exchange Rate (U.S.$:Cdn$)[4]	0.7452	0.7630	0.7660	0.7712

[1] Economic assumption based on calendar year, 2020/21 to 2021/22 from Ministry of Finance September 2020 First Quarter Report; 2022/23 to 2023/24 from Conference Board of Canada – August 2020.
[2] Includes the impact of Demand Side Management programs.
[3] Excludes system exports.
[4] Financial assumptions from Ministry of Finance, October 2020.

Sensitivity Analysis

Factor	Change	Approximate change in 2021/22 earnings before regulatory account transfers (in $ millions)
Customer Load[1]	+/- 1%	35
Interest Rates[2]	+/- 100 basis points	30
Electricity/Gas trade margins[3]	+/- 10%	30
Hydro Generation (GWh)[4]	+/- 1%	10
Exchange rates (US/ CDN)	+/-$0.01	5

[1] Assumes a percentage change is applied equally to all customer classes. Assumes a change in customer load is offset by a corresponding change in system imports or exports.
[2] Relates to debt subject to interest rate variability.
[3] Trade revenues less trade energy costs.
[4] Assumes a change in hydro generation is offset by a corresponding change in system imports or exports.

Management's Perspective on the Financial Outlook

In December 2020, BC Hydro filed an application with the BCUC for its revenue requirements for 2021/22. BC Hydro expects a decision in spring 2021 which may change the financial projections for revenues and expenses.

The current financial projections for revenues and expenses through 2023/24 were approved by the BC Hydro Board of Directors and submitted to the Ministry of Finance in March 2021.

The COVID-19 pandemic continues to adversely impact global economic activity and has contributed to significant volatility in financial markets. The pandemic could have a sustained adverse impact on economic and market conditions and could adversely impact BC Hydro's future performance if it were to cause a prolonged decrease in customer load, volatility in electricity/gas trade margins and interest rates, difficulty accessing debt, project delays and project cost escalations.

While BC Hydro engages in emergency preparedness (including business continuity planning) to mitigate risks, the persisting uncertainty of this situation limits the ability to predict the ultimate adverse impact of COVID-19 on BC Hydro's performance, financial condition, results of operations and cash flows.

This plan contains forward looking statements, including statements regarding the business and anticipated financial performance of BC Hydro. These statements are subject to a number of risks and uncertainties such as customer load, interest rates, electricity/gas market conditions and our ability to deliver our capital projects on-time and on-budget. These and other risks and uncertainties may cause actual results to differ from those contemplated in the forward-looking statements.

Capital Expenditures by Year and Type and Function

($millions)	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast	2023/24 Forecast
Capital Expenditures by Type[1]				
Sustaining	1,004	1,146	1,259	1,234
Growth	2,569	3,592	3,154	2,071
Subtotal – BC Hydro Capital Expenditures before CIA	3,573	4,738	4,413	3,305
Contributions-in-Aid (CIA)[2]	(160)	(214)	(167)	(171)
Total – BC Hydro Capital Expenditures net of CIA	3,413	4,524	4,246	3,134
Generation	351	388	427	486
Transmission and Distribution	891	995	1,091	1,153
Properties, Technology and Other	224	226	210	215
Site C Project[3]	2,107	3,129	2,685	1,451
Subtotal – BC Hydro Capital Expenditures before CIA	3,573	4,738	4,413	3,305
CIA	(160)	(214)	(167)	(171)
Total BC Hydro Capital Expenditures net of CIA	3,413	4,524	4,246	3,134

1. BC Hydro classifies capital expenditures as either sustaining capital or growth capital:
    - Sustaining capital includes expenditures to ensure the continued availability and reliability of generation, transmission and distribution facilities. It also includes expenditures to support the business, such as vehicles and information technology.
    - Growth capital includes expenditures to meet customer load growth and other business investments. Growth capital includes expenditures to expand existing generation assets as well as expand and reinforce the transmission and distribution system, and includes Site C.
2. Contributions in aid of construction are amounts paid by certain customers toward the cost of property, plant and equipment required for the extension of services to supply electricity.
3. Site C project forecast expenditures have been updated to reflect the costs estimated at $16 billion, which was announced on February 26, 2021.

Projects over $50 million

BC Hydro has the following projects, each with capital costs expected to exceed $50 million, listed according to targeted completion date. These projects have been approved by the Board of Directors.

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Dec 31, 2020 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Capital Cost of Project ($ millions)
Projects Recently Put Into Service				
Fort St. John and Taylor Electric Supply This project maintained adequate supply capability, reduced line losses and improved reliability to the loads in the Fort St. John and Taylor areas by re-terminating 138kV transmission lines at the new Site C switchyard, and the addition of a 75 MVA transformer and new feeder positions.	2020 In-Service	$51	$1	$52
UBC Load Increase Stage 2 Project This project was on behalf of BC Hydro's customer, the University of British Columbia, to continue to reliably meet the growing electricity needs of its Point Grey campus and the surrounding community.	2020 In-Service	$48	$7	$55

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Dec 31, 2020 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Total Capital Cost of Project ($ millions)
Ongoing				
South Fraser Transmission Relocation Project* This project is intended to relocate certain sections of two 230kV transmission circuits (Circuit 2L62 and Circuit 2L58) from their present location adjacent to Highway 99 and in the George Massey tunnel to accommodate the replacement of the tunnel. These two 230kV circuits form a critical part of BC Hydro's transmission network supplying power to customers in Richmond, Delta and the Greater Vancouver area. ***Construction work on the South Fraser Transmission Relocation project is currently suspended pending the government's review of the George Massey Tunnel replacement.***	TBD	$30	$46	$76
Downtown Vancouver Electricity Supply: West End Strategic Property Purchase This project is to acquire property rights to build and connect a new underground substation that will upgrade the aging electricity system in downtown Vancouver.	2021 Targeted In-Service	$67	$14	$81

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Dec 31, 2020 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Total Capital Cost of Project ($ millions)
Peace Region Electricity Supply (PRES) Project This project is needed to provide sufficient transmission system capacity to serve load growth and increase the reliability of electricity supply to existing customers in the South Peace. This project will facilitate reductions in provincial greenhouse gas emissions by enabling electrification of natural gas production, processing, and compression. **The total cost represents the gross cost of the project and has not been netted for potential Federal Government contributions.*	2021 Targeted In-Service	$193	$92	$285*
LNG Canada Load Interconnection Project This project is to facilitate the interconnection of LNG Canada's facility. A new double circuit 287kV transmission line will be constructed from Minette Substation (MIN) to LNG Canada's facility and system reinforcements at MIN will also be implemented. Under BC Hydro's standard tariffs, the customer is required to pay for a portion of this project's costs. **The total cost represents the gross cost of the project and has not been netted for a customer's contribution of $24M.*	2021 Targeted In-Service	$65	$17	$82*

Major Capital Projects (over $50 million)	**Targeted Completion Date (Calendar Year)**	**Project Cost to Dec 31, 2020 ($ millions)**	**Estimated Cost to Complete ($ millions)**	**Approved Total Capital Cost of Project ($ millions)**
Bridge River 2 Upgrade Units 7 and 8 Project This project will replace the two generators and other related equipment to restore the historical operating capacity. Units 7 and 8 were placed into service in 1960, are unreliable and in poor and unsatisfactory condition.	2021 Targeted In-Service	$50	$36	$86
Wahleach Refurbish Generator Project This project will improve the reliability of the generator at Wahleach Generating Facility, and its scope includes replacement of the stator and rotor poles, refurbishment of the remaining major components, and a combination of new, replacement, and refurbishment of the auxiliary components. The project also includes the installation of a new powerhouse crane and structural upgrades to the powerhouse building.	2022 Targeted In-Service	$24	$27	$51
Mica Replace Units 1 to 4 Generator Transformers Project This project will address the reliability and safety risks of the Unit 1-4 Generator Step-up Unit transformers at the Mica Generating Station, which are nearing end of life. There is a heightened reliability and safety risk from continuing to operate these transformers in an underground powerhouse as they age.	2022 Targeted In-Service	$41	$39	$80

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Dec 31, 2020 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Total Capital Cost of Project ($ millions)
G.M. Shrum G1 to 10 Control System Upgrade This project will replace the controls equipment, provide full remote-control capability from the remote-control center, and rectify deficiencies in the current system. The condition of the legacy controls for the GMS generating units, which were originally installed in the 1960s and 1970s, is of growing concern due to increasing maintenance requirements, lack of available spare parts and decreasing reliability. The controls are well beyond their expected life, which causes operating problems and increases the risk of damage to major equipment.	2022 Targeted In-Service	$51	$24	$75
Mount Lehman Substation Upgrade Project This project will increase the firm capacity of the Mount Lehman Substation to address safety and asset health concerns at both the Clayburn and Sumas Way substations.	2023 Targeted In-Service	$20	$39	$59

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Dec 31, 2020 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Total Capital Cost of Project ($ millions)
Street Light Replacement Program The program will convert approximately 95,000 BC Hydro owned and maintained High Pressure Sodium (HPS) and Mercury Vapour (MV) street lights to Light Emitting Diode (LED) street lights. This is required to meet federal polychlorinated biphenyl (PCB) environmental regulations by the end of 2025, manage increasing operations and maintenance costs, and better meet our customers' expectations. Lights have started to be converted and conversions will complete in 2023.	2023 Targeted In-Service	$4	$76	$80
5L063 Telkwa Project This project will increase the reliability and reduce the safety risks of the 500kV radial transmission line (5L063) that provides service for customers in Northwest British Columbia. A portion of the 5L063 line will be relocated away from the current area of unstable terrain.	2023 Targeted In-Service	$15	$51	$66
Mica Modernize Controls Project This project will address the reliability, maintainability, and operability of the Units 1-4 exciters, governors, unit controls and control room controls at the Mica Creek Generating Station.	2023 Targeted In-Service	$26	$30	$56

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Dec 31, 2020 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Total Capital Cost of Project ($ millions)
Capilano Substation Upgrade Project This project will address the existing asset health, reliability, safety, and environmental issues associated with the Capilano Substation, and to ensure that the capacity of the substation meets the long term area needs. The project will also introduce a 25kV source to enable 25kV voltage conversion and facilitate the execution of other future substation projects in the North Shore area.	2024 Targeted In-Service	$11	$76	$87
Sperling Substation (SPG) Metalclad Switchgear Replacement Project This project will address the existing asset health, reliability and safety risks associated with the 12kV 60 series feeder section and the bulk oil breaker in the 12 kV 70/80 series feeder section, insufficient electrical clearances in the 60 series feeder section, and arc flash safety risks associated with the 12kV indoor metalclad switchgear.	2024 Targeted In-Service	$5	$49	$54

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Dec 31, 2020 ($ millions)	Estimated Cost to Complete ($ millions)	Estimated Total Capital Cost of Project ($ millions)
Site C Project*** This project will construct a third dam and a hydroelectric generating station on the Peace River approximately seven kilometres southwest of Fort St. John. It will be capable of producing approximately 5,100 gigawatt-hours of electricity annually and 1,100 megawatts of capacity. Site C will provide clean, renewable and cost-effective power in B.C. for more than 100 years. **Planned in-service date for all units.* ***Site C project total anticipated cost and project cost to date include capital costs, charges subject to regulatory deferral and certain operating expenditures.* ****As announced on February 26, 2021, the cost of the Site C project is estimated at $16 billion, with a one year delay to 2025 for the project in-service date.BC Hydro continues to review the updated cost estimate, along with risks, further to recommended actions in the Milburn Report*	2025* Targeted In-Service	$6,455	$9,545	$16,000**

Information Technology (IT) Projects over $20 million

BC Hydro has the following IT project with capital costs expected to exceed $20 million. This project has been approved by the Board of Directors.

Significant IT Projects (over $20 million in total)	Targeted Completion Date (Calendar Year)	Project Cost to Dec 31, 2020 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Capital Cost of Project ($ millions)
Project Recently Put Into Service				
Supply Chain Applications Project This project replaced BC Hydro's existing PassPort supply chain information technology (IT) system with an SAP-based IT system and made improvements to BC Hydro's supply chain business processes for third-party materials and service acquisitions.	2020 In-Service	$67	$2	$69

Appendix A: Additional Information

Corporate Governance

Information about Corporate Governance can be found at:

http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html.

This includes links to information regarding, and includes all information detailed in the Best Practice Guidelines: Governance and Disclosure Guidelines for Governing Boards of British Columbia Public Sector Organizations:

- Board of Directors
- Executive Team
- Code of Conduct
- Board Governance Manual

Organizational Overview

Information about BC Hydro's organizational overview can be found at:

https://www.bchydro.com/toolbar/about.html

This includes links to information about BC Hydro's operations, governance and mandate.

Appendix B: Subsidiaries and Operating Segments

Active Subsidiaries

As wholly-owned subsidiaries, and like BC Hydro itself, Powerex Corp. and Powertech Labs Inc. follow best practices in corporate governance and subsidiary activities align with BC Hydro's mandate, strategic priorities and fiscal plan.

Powerex Corp.

Powerex Corp., an energy marketer, is a wholly-owned corporate subsidiary of BC Hydro and a key participant in wholesale energy markets across North America. Powerex's business consists of trading wholesale power and natural gas, environmental products (renewable energy credits or other similar products), carbon products (allowances and other similar products), ancillary energy services, and financial energy products.

Through its contractual agreements with BC Hydro, Powerex supports BC Hydro's system requirements by importing and exporting energy. Powerex also markets, through a contractual agreement with the Province, the Canadian Entitlement to the Downstream Power Benefits under the Columbia River Treaty.

The Chief Executive Officer (CEO) of Powerex reports directly to the Board of Directors of Powerex. The Chair of the Powerex Board ensures the Board of BC Hydro is informed of Powerex's key strategies and business activities. The Powerex CEO also informs the BC Hydro President & CEO and Executive Team of Powerex's key strategies and business activities.

Powerex operates in competitive and complex wholesale energy-markets, which can cause net income in any given year to vary significantly. Market, economic and weather conditions, reduced hydro system flexibility, unrealized mark-to-market gains or losses and the strength of the Canadian dollar can materially impact Powerex net income. The Service Plan forecast includes annual trade income from Powerex of approximately $190 million per year for 2021/22 to 2023/24, based on the average earnings over the last five fiscal years. For more information, visit powerex.com

Board of Directors:

- Ken Peterson – Chair
- Len Boggio
- Valerie Lambert
- Chris O'Riley

Powertech Labs Inc.

Powertech Labs Inc., operating in Surrey since its inception in 1979, is a wholly-owned subsidiary of BC Hydro. Powertech is internationally recognized as technical experts in a range of fields related to the electric utility and clean energy industries and offers services and solutions including performance and type testing, asset lifecycle management solutions, engineering studies, and power system modelling and analysis to energy clients, including BC Hydro, and other sectors globally. Powertech is also a technical leader in hydrogen energy, providing certification, performance, and safety testing services for hydrogen components and systems, as well as the design and construction of innovative hydrogen vehicle refueling systems.

The President and CEO of Powertech reports to Powertech's Chair of the Board. The Powertech Board is chaired by BC Hydro's President and CEO and its Directors include senior Executives of BC Hydro.

The Service Plan forecast includes annual net income from Powertech ranging from approximately $2 to $4 million per year for 2021/22 to 2023/24. For more information, visit powertechlabs.com.

Board of Directors:

- Chris O'Riley - Chair
- Melissa Holland
- Kip Morison
- David Wong

Other Subsidiaries

BC Hydro has created or retained a number of other subsidiaries for various purposes, including holding licences in other jurisdictions, to manage real estate holdings and to manage various risks.

All the staff and management needs of the active subsidiaries below are fulfilled by BC Hydro employees, who perform these duties without additional remuneration. Three of these subsidiaries are considered active:

BCHPA Captive Insurance Company Ltd.
Procures insurance products and services on behalf of BC Hydro.

Columbia Hydro Constructors Ltd.
Administers and supplies the labour force to specified projects.

Tongass Power and Light Company
Provides electrical power to Hyder, Alaska from Stewart, B.C. due to its remoteness from the Alaska electrical system.

Nominee Holding Companies and/or Inactive/Dormant Subsidiaries
BC Hydro's remaining subsidiaries either serve as nominee holding companies (indicated with an *) or are considered to be inactive/dormant. The inactive/dormant subsidiaries do not carry on active operations. As of February 28, 2021, these other subsidiaries consisted of the following:

1. British Columbia Hydro International Limited
2. British Columbia Power Exchange Corporation
3. British Columbia Power Export Corporation
4. British Columbia Transmission Corporation
5. Columbia Estate Company Limited*
6. Edmonds Centre Developments Limited*
7. Fauquier Water and Sewerage Corporation
8. Hydro Monitoring (Alberta) Inc.*
9. Victoria Gas Company Limited
10. Waneta Holdings (US) Inc.*
11. 1111472 BC Ltd.

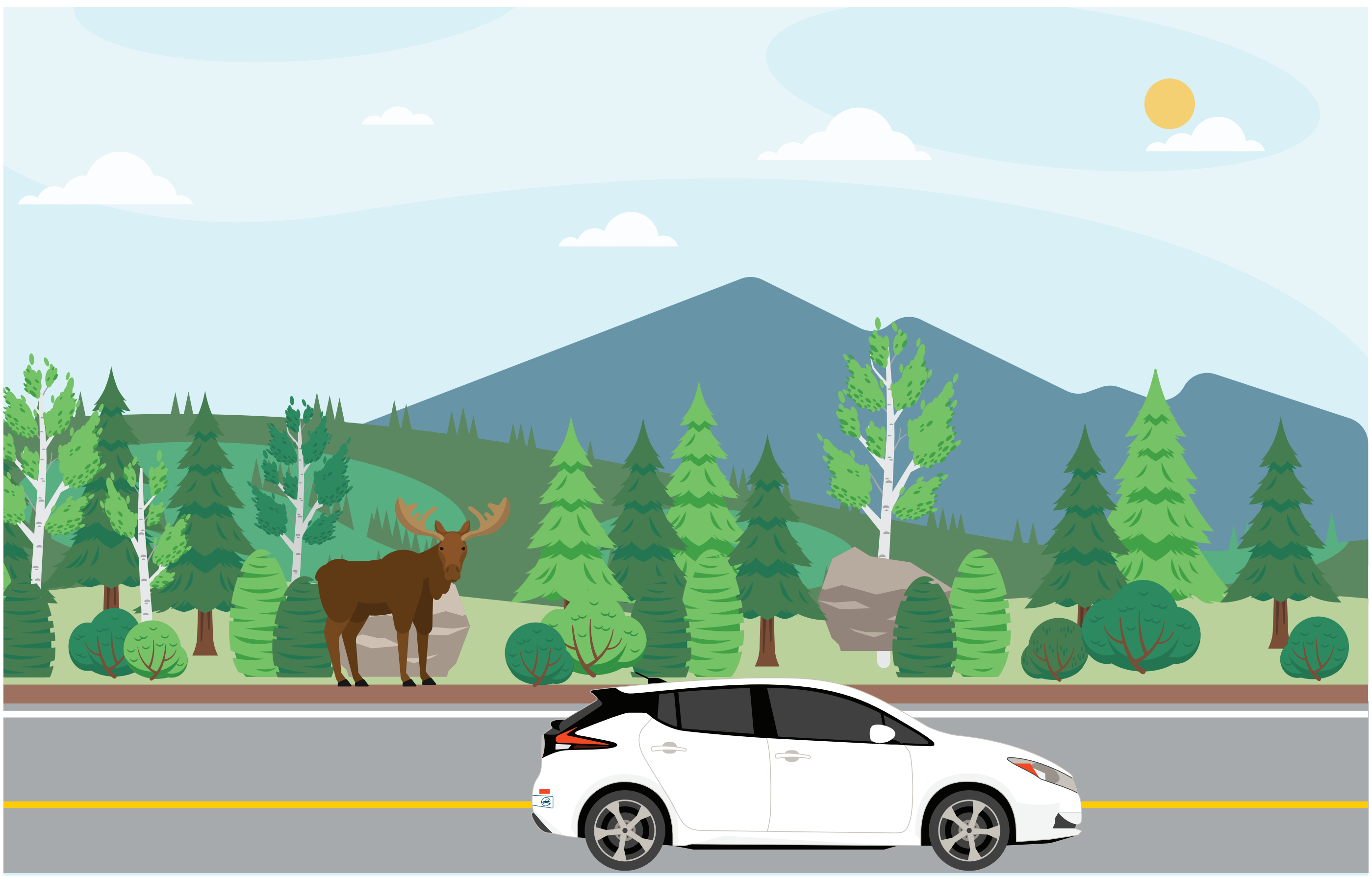
BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix D

Five-year Strategy

Powering a cleaner more sustainable future for all British Columbians

BC Hydro's five-year strategy Fiscal years 2022 – 2026



BC Hydro Power smart

CS–16

Contents

How we operate

At its core, our job is to safely keep the lights on for the people of British Columbia.

This work is constant, complex and important to who we are as a utility.

- It's about planning and managing our reservoirs, generation and downstream discharges, while also considering factors like dam safety, flooding, and fish and fish habitat.
- It's about having the right people and processes in place to safely restore power when a storm brings widespread outages to our neighbourhoods.
- It's about making sure we keep goods and services moving through our company so that everything from pens to power poles to personal protective equipment (PPE), gets where it's needed on time.
- It's about building relationships within our communities and supporting customers who reach out about everything from programs and bill requests, to reporting outages and requesting new connections.
- It's about keeping safety at the heart of everything we do, so that every person working for BC Hydro and interacting with our system goes home safely each day.
- It's about operating our system and making the right capital investments to support our customers' needs today, tomorrow and 20 years from now.

Our core work doesn't change.

An ambitious plan for a sustainable future

This plan represents our strategy for the next five years, ending in fiscal year 2026.

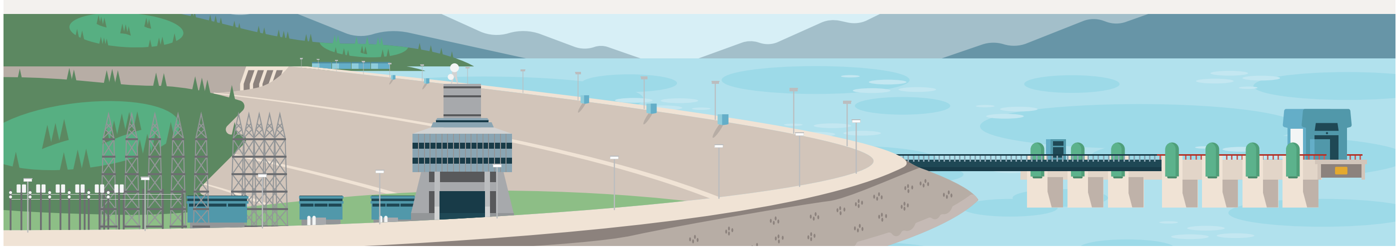
It lays out where we are choosing to invest in addition to our core work. Focusing on these areas will allow us to maximize opportunities, manage challenges, and leave BC Hydro and British Columbia more resilient and better off.

We've considered the outcomes of the government's Comprehensive Review of BC Hydro to contain rate increases, control costs and position BC Hydro for future success. We've accounted for the significant changes and shifts taking place in B.C. and continental energy sectors, in addition to evolving technologies and the changing needs of current and future BC Hydro customers.

We recognize the opportunity we have to strengthen relationships with Indigenous communities. We know our clean electricity can make significant positive impact on climate change and the environment by supporting the reduction of greenhouse gas (GHG) emissions.

This is an ambitious plan. Achieving the objectives we've laid out will require us to make trade-offs to get the most out of scarce resources. It will take targeted investment, organizational focus, and hard work.

We are up for the challenge.



Five years is just a snapshot of a much longer path forward

Doug Allen
Board Chair

Chris O'Riley
President &
Chief Executive Officer

Hi everyone,

We are fortunate to be part of BC Hydro at this juncture in its history; our industry is standing on the precipice of change and we are looking out at new opportunities and growth.

At the same time, we must balance our optimism for the future, with a critical look and appreciation for our changing landscape and the challenges before us. These times call for a clear understanding of our situation and an articulation of a viable path forward.

Our sector is experiencing transformational trends in areas like climate change, technological advances, and the evolution of customer energy use. At the same time, we are dealing with the immediate impacts and uncertainties of the COVID-19 pandemic. The intersection of these events points to the need to reflect on what has driven our success up to now, and what will drive our success moving forward.

Since its formation, BC Hydro has played a pivotal role in the growth and economic prosperity of British Columbia. Development of some of the world's most ambitious hydroelectric projects in the 1960s, 70s and 80s has endowed our province with a large-scale hydro reservoir system that provides an abundance of flexible capacity and clean electricity. Successfully completing Site C will further contribute to this legacy providing British Columbians with clean, reliable and affordable electricity for the next 100 years. While the system has evolved over the years, capacity and flexibility are, and will continue to be, a differentiating strength. Our clean energy has the potential to make a massive difference to the health of the environment, both within B.C. and beyond by displacing more carbon intensive energy sources.

"Development of some of the world's most ambitious hydroelectric projects in the 1960s, 70s and 80s has endowed our province with a large-scale hydro reservoir system that provides an abundance of flexible capacity and clean electricity."

We have a big task before us. We are embarking on the development of our next Integrated Resource Plan, we're completing work to understand and meet the evolving needs of our customers and there's an important role for us to play in supporting British Columbia's climate action and economic growth objectives. Throughout, our core work of providing our important service to our customers will remain constant. It's imperative that we have a corporate strategy in place to guide us as we invest and work toward our refreshed vision: a cleaner, more sustainable future for all British Columbians.

Ours is a long game. Five years is just a snapshot of a much longer path forward. It represents an opportunity to make incremental progress in those areas that will ensure British Columbians get the most benefit from the strengths of the system we manage.

This strategy represents the culmination of a huge amount of work done by staff, the Executive Team and members of the Board on many different streams, including the Government's Comprehensive Review, over the past several years.

We thank everyone for their passionate involvement.

Thriving in a dynamic world

Our plan takes into consideration the environment we operate in, the strengths we have as an organization and the opportunities and challenges that lie ahead.

Check out Appendix B for more details on these considerations.

Here are some of the key drivers that influenced our thinking:

- **Climate Change** is impacting how our system operates, and driving focus on clean energy
- **Technology** is changing how electricity is produced, distributed, and consumed
- **Grid modernization** is enabling efficiency and new functionality
- Increased demand for **storage and capacity resources**
- Commitment to **Indigenous reconciliation and Calls to Action of the Truth and Reconciliation Commission**
- **COVID-19** impacts
- **Customers expect more** information, input into decisions and involvement in managing energy use
- **Economic shifts** have changed who is consuming energy and how much

Site C: a multi-generational investment in affordable, reliable and renewable energy

As we launch this five-year strategic plan, the construction of Site C is at the halfway mark. The project, which will provide British Columbians with clean, reliable and affordable electricity for the next 100 years, is one of the most significant infrastructure investments undertaken in B.C. in recent history.

In October 2020, Site C reached its most important milestone to date when the Peace River was successfully diverted around the dam site. The project also completed and energized the Site C substation, and the first of two new transmission lines was placed into service. Both of these milestones were completed ahead of schedule.

The difficulties facing the project are considerable and have resulted in significant challenges for our team. The global COVID-19 pandemic, along with the need for foundation enhancements on the right bank to deal with unanticipated geotechnical conditions, have resulted in schedule delays and significant cost pressures to completing Site C.

BC Hydro will work with government to implement recommendations resulting from the recent independent review of the Site C project to enhance oversight and management of the project. BC Hydro is committed to completing Site C safely, meeting all compliance requirements, within the revised project schedule and budget.

Successfully completing Site C is key to this strategy and our vision of powering a cleaner more sustainable future for all British Columbians. Site C will provide the clean energy needed to grow our load and decarbonize the economy through electrification. Its clean capacity will support the integration of renewables now and into the future.

A look at our five-year plan

Our mission
stays constant

It's the driver of our core work

We are here to safely provide our customers with reliable, affordable, clean electricity.

Our vision
for the future is clear

It's clean power

A cleaner, more sustainable future for all British Columbians.

Our values
define our culture

They guide our approach to powering the province

We are safe.

We are here for our customers.

We act with integrity and respect.

We are one team.

We are forward thinking.

We include everyone.

To get where we want to be, we'll need to focus on what our province needs.

- Maintain affordability of electricity.
- Meet rising customer expectations.
- Reduce greenhouse gas emissions through efficient electrification.
- Advance reconciliation with Indigenous Peoples.

FOUROVERFIVE

Four goals make up our plan to move BC Hydro forward over the next five years.

- Grow our load
- Control our costs
- Strengthen our resilience and agility
- Advance reconciliation with Indigenous Peoples

A refreshed vision and values

Our vision celebrates our clean energy advantage and our environmental stewardship role in B.C. Sustainability is about making the best choices with available resources; this means leveraging our clean electricity for all British Columbians. For us, respect for our province and the integrity to act in good faith go hand-in-hand, so we've combined these values. To be successful, we need to include a diversity of perspectives and experiences in our decision making. Our new value—We include everyone—declares this expectation and our responsibility to one another.

Four goals will carry us forward

1 Grow our load

Increase load through low carbon electrification.

Develop and implement rate design strategy.

Implement Site C review recommendations and successfully complete Site C.

Strengthen our business development and sales capabilities.

Promote electric vehicle adoption.

Increase understanding of customers.

Develop Integrated Resource Plan.

Identify opportunities for Indigenous Nations.

Cost-effective efficiency programs.

Attract new industries to B.C.

Adopt 100% Clean Energy Standard.

2 Control our costs

Continue culture of cost management.

Pursue agile technology solutions.

Implement integrated work management system.

Achieve process improvements.

Achieve benefits from improved procurement and supply chain.

Build compelling Revenue Requirements Applications.

3 Strengthen our resilience and agility

Implement robust compliance program.

Complete implementation of safety management and assurance system.

Increase investment in training and development.

Increase investment in cybersecurity.

Increase investment in vegetation management and Mandatory Reliability Standards compliance.

Implement COVID-19 learnings. Improve support for front-line employees.

Strengthen our inclusivity.

4 Advance reconciliation with Indigenous Peoples

Finalize Relationship Agreements.

Develop and implement UNDRIP plan.

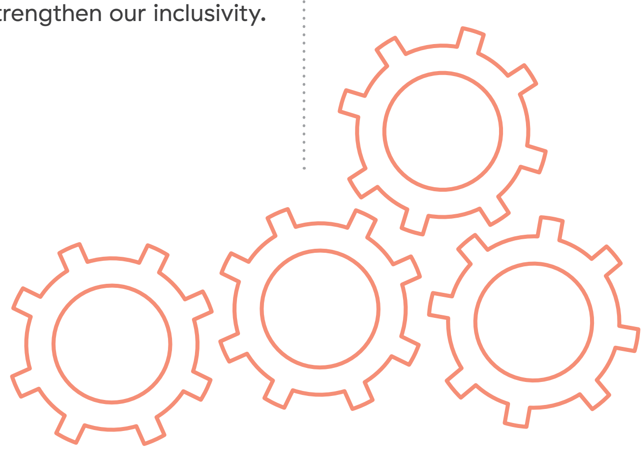
Explore new Indigenous procurement opportunities.

Increase opportunities for Indigenous employment.

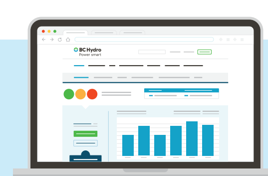
Reduce reliance on diesel generation.

Pursue ownership opportunities such as new radial transmission.

Increase engagement and participation in planning.



We'll track our progress and measure our success as we go along using clearly defined metrics (see Appendix A).



Grow our load

Why it's important

Maintaining and efficiently growing load is a critical part of how we keep our rates affordable and competitive for our customers.

Over the last number of years, we've seen load declining in some sectors due to economic factors and shifts in how we use energy.

Adding to this pressure is the unprecedented loss of load due to the COVID-19 pandemic.

Globally, we're seeing the world react to climate change and the need to urgently reduce carbon emissions. In B.C., we already know the power of clean electricity. We know that encouraging customers to switch to our clean electricity supports the reduction of greenhouse gas emissions (GHGs). The opportunity to grow load through electrification is significant—currently electricity represents only 19% of total energy consumption in B.C.

We have an opportunity to use our clean electricity to electrify the economy. The positive impact electrification can have on the environment, both within B.C., and beyond, is significant. B.C. will need more renewable energy to support growth, transition away from fossil fuels and meet our climate targets. Site C will help our province achieve these important objectives. Wherever possible, we'll extract more value out of technology and infrastructure we've already put in place to avoid the development of additional significant generation infrastructure. Growth can only be successful when we also focus on understanding and delivering on the needs of our existing customers as well as potential new customers.

The affordability equation

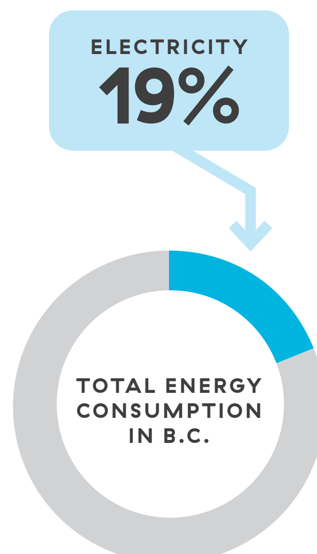
Our rates are the result of dividing the costs to run the system by the volume of electricity we sell.

As with other utilities, many of our costs are fixed, which means they stay the same whether we sell more or less electricity.

How does this relate to rates and affordability for our customers? You can think of it like a math equation or "affordability equation." Our rates are essentially the result of an equation where costs are the numerator and electricity demand is the denominator.

$$\frac{\text{COSTS}}{\text{DEMAND}} = \text{RATES}$$

When electricity demand falls, it puts upward pressure on future rates as our system costs need to be recovered through a lower volume of electricity sales. And when costs increase without load growth or productivity gain, we see a negative impact on affordability.



Grow our load

What we plan to do

- Develop an electrification plan to grow existing and secure new load, pursuing efficient electrification opportunities with industrial customers, the transportation sector, and the built environment (structures and buildings).
- Develop and implement a rate design strategy that supports the objectives of economic efficiency, affordability, decarbonization, and flexibility, and promotes growth of load.
- Implement Site C review recommendations and successfully complete Site C.
- Strengthen our business development and sales capabilities and partner with government to promote B.C.'s clean electricity advantage.
- Implement transportation electrification measures that reduce customer connection costs, encourage off-peak charging of electric vehicles, build out charging infrastructure, and support the growing clean transportation economy.
- Use data analytics and engagement to better understand what our current and future customers need from BC Hydro.
- Develop an Integrated Resource Plan (IRP) to meet future load requirements of the system, while controlling costs.
- Identify opportunities for Indigenous Nations to participate in the efficient growth of electricity load in the province.
- Maintain cost effective efficiency programs, including programs targeted to low-income ratepayers, to support customers to be efficient with their current use of electricity and leverage these programs to offer low carbon electrification programs that encourage growth of electricity.
- Attract innovative new industries to British Columbia and promote B.C.'s clean energy advantage including leveraging Powertech Lab's leadership and experience.
- Pursue a 100% clean energy standard to ensure continued market access and to increase the value of our product.

What success will look like

- We have grown our load and reduced GHGs, balanced with efficiency and conservation, and have the revenue required to make key investments while maintaining affordability.
- We have safely completed Site C, within revised schedule and budget.
- We successfully managed the generation and transmission demands of our load growth while considering cost effectiveness, including mitigating system capacity impacts through rates such as optional time of use and demand response.
- We have helped our customers leverage government programs like the CleanBC Industry Fund to support GHG reduction through electrification.
- We have found opportunities for Indigenous Nations to participate in and benefit from efficient load growth.
- We have attracted new businesses to B.C. by being cost competitive. This could include new industries such as hydrogen, bio-technology, as well as highly mobile energy intensive operations like data centres. This diversification has mitigated load lost from declining sectors.
- The public and our customers clearly understand how conservation and load growth work together.

Growth and conservation: complementary strategies

Our demand-side management programs have always been about the smart and efficient use of electricity. In addition to providing customers with bill savings and giving us more flexibility on the system, it's a more sustainable use of our clean resource.

Electrification is about the efficient use of energy overall. Helping our customers switch to clean electricity helps us reduce carbon emissions.

In this way, growth and conservation are complementary strategies. We can encourage residential customers to improve home insulation to reduce heating costs, while also encouraging them to switch from a gas to an electric vehicle.

Grow our load

Measuring our success

Performance measures supporting five-year strategy	Targets
Load growth supporting CleanBC (GWh)	4700 GWh by end of F26
New connected commercial and industrial load (MW)	750MW (5000 GWh) by end of F26
GHG emissions reduction – electrification (tonnes CO_2e/year)	2.5 million tonnes/year by end of F26
GHG emissions reduction — BC Hydro operations	45% reduction from 2007 levels by 2025
Clean electricity standard	100% clean energy by Q3 F25
Customer Interconnection studies completed on time	80% annual target
Demand-side management capacity (MW)	Target to be developed and included in 2021 Integrated Resource Plan
Customer satisfaction index	85% annual target

Our environmental advantage: clean energy

CleanBC, the provincial government's plan for creating a more sustainable future, sets big goals—and we're a big part of them.

The plan outlines how we'll reduce our greenhouse gas emissions by transforming our buildings, transportation, and how we power our economy and use cleaner energy. A key component of how we'll do that is through clean electricity.

We used to say our conservation program, Power Smart, was our largest environmental program. Today, it's our electrification program because of the reach and affect it can have on emissions. Playing a bigger role in this space, gives us the opportunity to have meaningful impact on the environment, in the economy and in broader society.

CleanBC sets the stage for a new era at BC Hydro—one where clean electricity is the preferred energy source.

CleanBC GHG reduction targets

Sectoral GHG targets for 2030 are expressed as a percentage reduction from 2007 sector emissions:

- Transportation: 27 to 32%
- Industry: 38 to 43%
- Oil and gas: 33 to 38%
- Buildings and communities: 59 to 64%

$ Control our costs

Why it's important

Managing costs is critical to providing affordable and competitive rates that our customers expect.

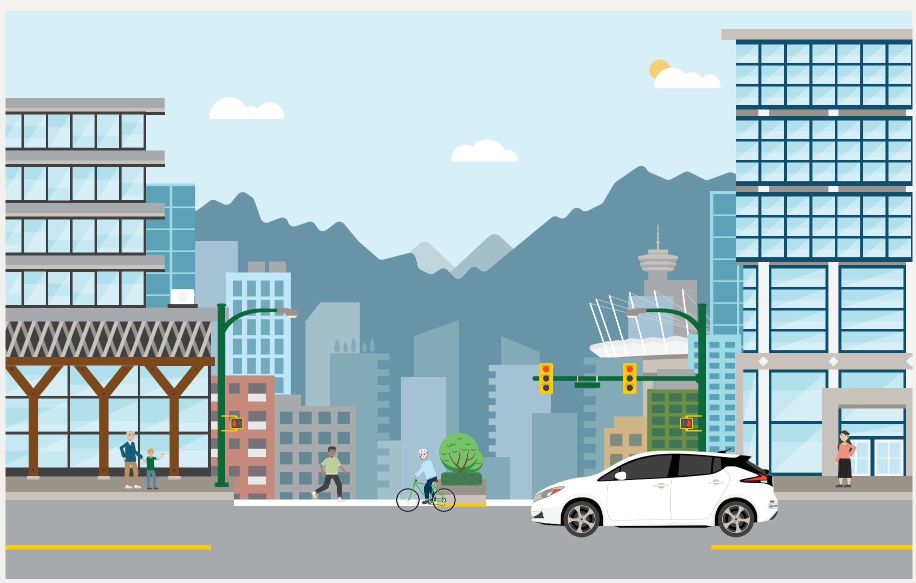
It allows us to address new demands on the business and make investments where they're needed most.

Our ability to absorb cost increases is being challenged and tested by the growing complexity of the business, particularly in areas such as critical infrastructure protection, mandatory reliability standards and cybersecurity. The pandemic has further reduced our revenues adding more pressure to our ability to manage costs.

We have an opportunity to build on the cost-control measures already taken as part of Phase One of the Comprehensive Review of BC Hydro. We'll make focused investments in systems that will increase our efficiency. We'll also identify process improvements that will allow us to meet growing expectations in a resource-constrained environment, while preserving our core mandate of affordability.

Expectations are high

What we're expected to deliver today is far more than the expectations placed on the utilities of the 1950s and 1960s. Along with the growth we've seen in society, there's also been an increase in the expectations for service, for accountability and corporate social responsibility, and for broad protection of the electrical grid. Understanding and meeting changing expectations will always be a focus and key to our success.



Control our costs

What we plan to do

- Continue to promote a culture of sustained cost management throughout the organization.
- Pursue agile technology solutions that are more modest in cost and have a smaller implementation burden than traditional enterprise solutions.
- Invest in an integrated work management system and business process that increases our efficiency and ability to deliver in a cost-constrained environment.
- Increase our capacity to meet growing expectations with existing resources through our process improvement program Work Smart.
- Achieve benefits of improved procurement and supply chain management practices and tools. This includes a focus on category strategies, contract and supplier management and supply chain related business process improvement.
- Encourage regulatory structures and requirements that permit achieving regulator's objectives at least cost to BC Hydro customers.
- Develop revenue requirements applications that build confidence and support for BC Hydro's cost management and budgeting.

What success will look like

- We have successfully managed cost pressures, matched capital investment to load, achieved efficiencies through process improvement and investment in systems, and have been able to maintain affordability for current and future customers.
- We have kept electricity rates affordable by ensuring that rates do not increase above inflation, on a cumulative basis, for the period of Fiscal 2022 to Fiscal 2030.
- We have undertaken necessary investments in management systems and processes required to minimize costs and employ BC Hydro's human and physical capital as efficiently as possible.
- We have maximized opportunities via Powertech and Powerex to maintain affordability and keep rates low.

Control our costs

Measuring our success

Performance measures supporting five-year strategy	Targets
Affordable bills	1st Quartile (residential, commercial and industrial customer classes) annual target
Project budget to actual cost: cumulative five-years	Within +/– 5% of budget excluding reserve amounts

Clean Power 2040: Our power system strategy

The Integrated Resource Plan (IRP), Clean Power 2040, is our long-term plan for cost-effective delivery of secure and reliable energy services over a 20-year horizon: it's the what, when and why of our actions to meet customers' evolving electricity needs. The outcomes of the Comprehensive Review and this strategy provide policy direction and strategic context for our next IRP.

For example: Clean Power 2040 will consider the power system impacts of increased electric vehicle use and actions to manage system capacity constraints. The insights gained may inform our approach to implementing our Electric Vehicle (EV) strategy.

Strengthen our resilience and agility

Why it's important

We need to be prepared for threats ranging from cybersecurity attacks and impacts of climate change, to natural disasters and global pandemics.

Training and development, robust compliance, financial discipline, and strong safety performance all support resilience and ensure our people, assets and facilities are safe. Considering the effects of climate change on our system allows us to plan better and increase our resilience to impacts such as extreme weather events or changes in precipitation patterns impacting our reservoirs. Maintaining the financial health of the organization increases our resilience to challenging economic conditions. It also gives us greater flexibility to take advantage of commercial opportunities.

The day-to-day work we do to deliver on our core business is getting more and more complex. The flexibility and skills employees are demonstrating during the pandemic represent the type of agility we'll need to foster moving forward to be successful in our strategy, as well as our evolving sector. We also need to focus on becoming a more inclusive workplace to give our employees the space to deliver their best work.

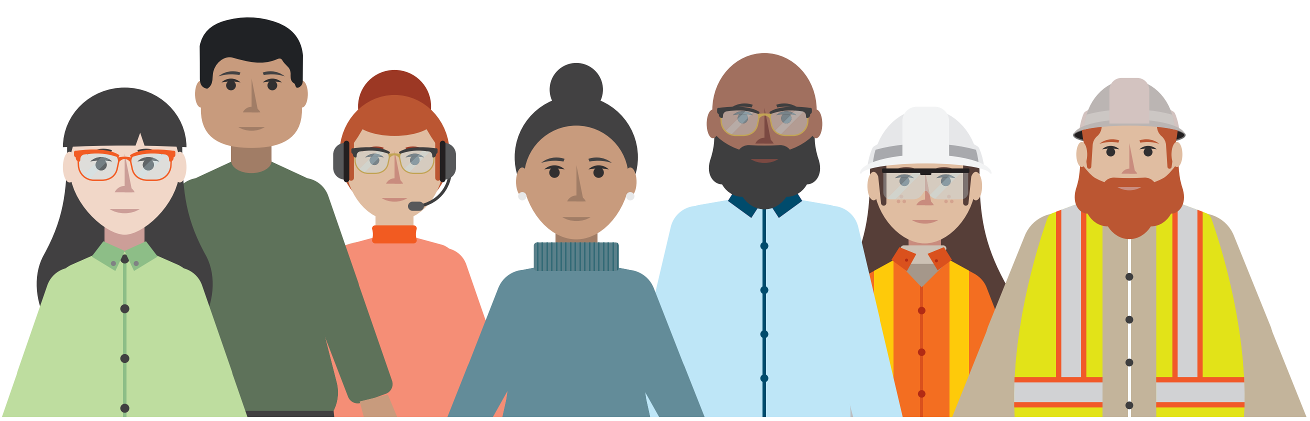
Resilience is the new reliability

resilience [ri-'zil-yən(t)s] *noun*
The capacity to recover quickly from difficulties.

Resilience sets us up to manage through challenges and prevents disruptions to the important service we provide. Being resilient enables reliability—something our customers count on—and it gives us the space to be agile, while knowing our core functions continue to operate successfully.

agility [ə-'ji-lə-tē] *noun*
The ability to think, understand and act quickly.

Agility allows us to position our company to take advantage of opportunities when they arise, and to innovate and find better ways of doing things. Agility is an organizational characteristic we must continue to strengthen.

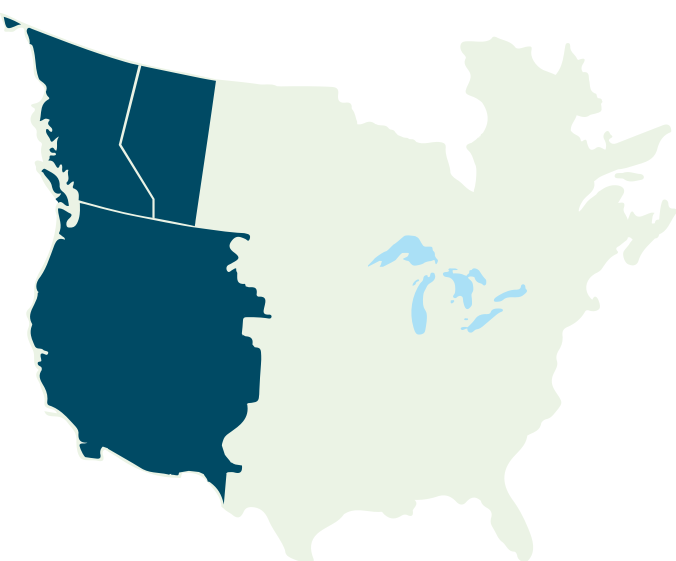


Strengthen our resilience and agility

What we plan to do

- Implement a robust compliance program.
- Complete implementation of a safety management and assurance system to improve the safety performance of our employees and contractors.
- Increase investment in training and development focused on building workforce capabilities that support resilience.
- Increase our investment to defend against cybersecurity threats.
- Increase investment in vegetation management and mandatory reliability standards compliance.
- Implement flexible work model for our office-based employees that incorporates learnings from the pandemic and supports further development of our workforce and properties strategies.
- Improve how we support our front-line employees and managers to safely deliver reliable, clean, and affordable electricity.
- Strengthen our inclusivity within the organization and in the way we engage externally.

WESTERN INTERCONNECTION



What success will look like

- We are in full compliance with all regulatory requirements, have systems to effectively implement new requirements, and are resilient to external threats and disruptions.
- We have built on our experiences during the pandemic and further institutionalized our agility and ability to adapt across a range of domains from technology to workforce.
- A strong, inclusive, highly-engaged workforce that reflects the diversity of B.C.'s workforce.
- We have no significant compliance violations or successful cyber attacks.

More than compliance: Mandatory Reliability Standards

We're part of an interconnected electrical system that covers the western third of North America. Mandatory Reliability Standards (MRS) are designed to assure the reliability and security of that connected system. They were developed following a widespread blackout that affected over 50 million people in the eastern part of North America in 2003. With utilities around the world increasingly being targeted by cyber threats, we each need to do our part to comply with these standards to prevent this from happening again.

Compliance starts with awareness of the standards and how they apply to our work areas. Our MRS Internal Compliance Program outlines how we plan to set up our processes and controls across our company, with clear protocols and ensuring everyone gets the training needed for their work area.

Strengthen our resilience and agility

Measuring our success

Performance measures supporting five-year strategy	Targets
Employee engagement index	At or above Global Utility Index
Workforce diversity	Meet or exceed the representation in the available workforce by 2026: Indigenous people: 5% Women: 30% Visible minorities: 25% People with disabilities: 10%
Inclusion and diversity leadership training	100% of people leaders trained in inclusion and diversity leadership by end of F24
Training hours – operations (incremental to safety training)	34 Training Hours average per Operations employee annually
Zero fatality & serious disabling injury	Zero
Lost time injury frequency	F22 — 0.76 F23 — 0.74, and maintain thereafter
Mandatory Reliability Standards violations	12 or fewer violations in F26

Advancing reconciliation with Indigenous Peoples

Why it's important

Advancing reconciliation is an important part of the role BC Hydro plays in the province.

Reconciliation is a process of learning from our history and coming together to find a path forward. It starts with listening and understanding.

We recognize that mutually-beneficial relationships with Indigenous Nations are critical to operating and growing our system of clean electricity. As a Crown corporation, BC Hydro has an important role to play supporting the province's commitment to reconciliation. In 2019 the provincial government passed the *Declaration on the Rights of Indigenous Peoples Act*, to adopt the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP), which the Truth and Reconciliation Commission confirms as the framework for reconciliation.

We're working with Indigenous Nations to find meaningful paths to reconciliation. Our progress to date includes entering into 13 Relationship Agreements in addition to three historic grievance settlements, as well as other opportunities related to procurement and employment. We have a strong platform to continue building from.

We recognize that many remote communities not connected to our integrated system are Indigenous Nations. Due to many of these communities being serviced by diesel generation, they often face high electricity costs and reliability issues. This represents a significant opportunity for us to help address social and environmental concerns created by lack of access to reliable, clean electricity.

Celebrating Kwantlen's culture and history: Ruskin Dam collaboration

During the redevelopment of the Ruskin Dam an important Kwantlen archeological site was uncovered. Working together, BC Hydro and Kwantlen developed a cultural centre to house the artifacts that were discovered. This experience brought us closer together and led to six panels designed by a Kwantlen artist being installed on the Ruskin Dam. These panels acknowledge the depth of Kwantlen's spiritual, cultural and physical presence in the area, and our commitment to a lasting relationship with them that is built on reconciliation.

Advancing reconciliation with Indigenous Peoples

What we plan to do

- Renew existing Relationship Agreements and finalize four more with Indigenous Nations who are most impacted by our infrastructure.
- Meet our commitments in our Relationship Agreements.
- Develop and publish an UNDRIP implementation plan to demonstrate our commitment to reconciliation and to build transparency around our company's efforts.
- Meet or exceed our Indigenous procurement commitments (in addition to Site C) by exploring opportunities in other parts of our business such as Operations or Properties.
- Continue to create programs that increase opportunities for Indigenous employment and career growth at BC Hydro, such as the Indigenous Professionals in Development (IPID) program or the Try-a-Trade program.
- Reduce reliance on diesel generation in communities that are not connected to BC Hydro's integrated system.
- Pursue Indigenous ownership opportunities such as new BC Hydro radial transmission lines and customer connections.
- Increase opportunities for Indigenous Nations to participate in BC Hydro's planning decisions at a regional level, including co-designing approaches to minimize impacts on the land base.

What success will look like

- We have worked together with Indigenous communities to understand and further reconciliation in a way that creates sustainable benefits.
- All employees understand what UNDRIP is and what it means for BC Hydro and we are actively implementing our UNDRIP action plan.
- We have co-developed unique approaches to environmental protection with Indigenous Nations, such as a new approach to cumulative effects.
- We have successfully come to understand and navigate the complexity of relationships between Indigenous governments and the provincial government and have realized efficiencies in consultation and regulatory processes.
- We have played a role to help address capacity gaps in Indigenous communities and this has greatly helped communities achieve meaningful benefits and engagement with the energy system.
- We have developed new and innovative models for Indigenous participation that are aligned to our business, such as exploring different ownership models for transmission lines or new clean energy projects in remote communities.
- We have introduced new Relationship Agreement models that reflects the principles of UNDRIP and seek to address the ongoing impacts of our facilities.

Advancing reconciliation with Indigenous Peoples

Measuring our success

Performance measures supporting five-year strategy	Targets
Indigenous procurement	$1 billion by the end of F26 (cumulative since 2015)
Non-integrated areas (NIA) diesel reduction	TBD
Indigenous employment at BC Hydro	25% increase from F21 baseline by end of F26
Indigenous awareness training at BC Hydro	80% of employees trained in INDIG-101 and/or INDIG-201 by end of F26
Progressive Aboriginal Relations Certification	Gold level

Understand your role in the plan

This plan is our roadmap for the next five years. It helps frame the work we do at BC Hydro, now and in the future. It's ambitious, and we have the right team to get the job done.

We have an important job. Whether we're working on the electrical system at the front lines, supporting customers in our Contact Centre, managing water resources from our offices and control centres or procuring the goods and services we need to keep the lights on—all our work is important, and this core work always comes first.

We know that as the volume and complexity of our work increases, it can become more difficult to get our work done. This strategy helps us be thoughtful about where we put our incremental efforts over the next five years to maintain the service our customers count on, while also pushing forward to the future.

THINK AHEAD

Think about how your work supports our goals, or what might need to change to make them happen.

Think about how you and your team will have time and energy to advance the strategies.

TALK WITH YOUR TEAM

Get involved and have a voice. Speak up if you don't know or understand something.

Discuss how you can advance the priorities without making a bunch of new initiatives.

Acknowledge the constraints on all of us and be solutions-focused.

TAKE ACTION

Build the priorities into your work plans and performance objectives.

Keep talking with your team about our progress.

Appendix A: Measuring our success

Metrics and targets are an important component of measuring our success but they're not the only thing we need to pay attention to. Not everything is easily measured or quantified. In addition to our measures and targets, we also need to be accountable for qualitative outcomes. For example, it's difficult to quantify the quality of a relationship when thinking about advancing reconciliation with Indigenous Nations, yet this is a critical component of success. Our strategy contains metrics and targets, as well as descriptions of "what success looks like"—and are both important.

Grow our load	
Performance measures supporting five-year strategy	**Targets**
Load growth supporting CleanBC (GWh) This measure tracks growth in load (GWh) related to CleanBC (fuel switching and new clean industries) and represents efforts to support CleanBC through electrification.	*4700 GWh by end of F26 (measured against F20 actual results)
New connected commercial and industrial load (MW) This measure captures load from new or expanded commercial and industrial load.	*750MW (5000 GWh) by end of F26 (measured against F20 actual results)
GHG emissions reduction – electrification (tonnes CO_2e/year) This metric tracks performance on reducing GHGs and supporting CleanBC. It uses the results from the metric "Load Growth Supporting CleanBC" to calculate an associated GHG reduction benefit.	2.5 million tonnes/year by end of F26 (measured against F20 actual results)
GHG emissions reduction — BC Hydro operations (% reduction) This metric tracks BC Hydro's progress reducing GHG emissions related to its own operations in areas such as fleet, buildings, SF_6, non-integrated areas, independent power producers (IPPs), thermal, air travel, and supply chain.	45% reduction from 2007 levels by 2025
Clean electricity standard (% clean energy) This measure represents BC Hydro's provision of a sufficient quantity of clean energy to meet BC Hydro's annual average load served by the integrated power system over a four-year period of time. **Note — final methodology and target subject to government consultation and resulting legislation and regulation.**	100% clean energy by Q3 F25 and maintained thereafter
Customer interconnection studies completed on time (%) This measure tracks BC Hydro's performance meeting the overall timeline for the completion of studies (all types) required for customers to be connected to the grid. The measure encompasses the timeliness of actions of BC Hydro, the customers and third parties to complete the studies.	80% annual target

* The Load Growth Supporting CleanBC and New Connected Commercial and Industrial Load targets are not additive and are not designed to be mutually exclusive; there will be some new projects that are captured in both of the two metrics. Accounting for overlap, the combined targets represent 6,900 GWh/year of load growth from F2021 to F2026, an increment of 2,200 GWh for F2026 over the December 2020 reference load forecast (4,700 GWh). The new commercial/industrial load target measures gross new load growth and does not account for any loss of existing load.

Appendix A: Measuring our success

Grow our load	
Performance measures supporting five-year strategy	**Targets**
Demand-side management capacity (MW) This measure reflects the annual new incremental capacity (MW) savings from the energy conservation portfolio including programs, codes and standards and conservation rates that measure BC Hydro's performance against annual energy targets.	Target to be developed and included in 2021 Integrated Resource Plan
Customer satisfaction index (%) This is an index measuring customer satisfaction of BC Hydro's three main customer groups (residential, commercial and industrial). The index is comprised of the five key drivers of satisfaction weighted equally across the three customer types.	85% annual target

Control our costs	
Performance measures supporting five-year strategy	**Targets**
Affordable bills (quartile benchmark) This metric measures BC Hydro's average bills compared to a sample of North American utilities across three different customer classes, based on survey information taken from the annual Hydro Quebec report, Comparison of Electricity Rates in Major North American Cities.	1st Quartile (residential, commercial and industrial customer classes) annual target
Project budget to actual cost: cumulative five years (% variance) This measure compares actual project costs at completion (not including Site C) to the original approved full scope implementation budgets, not including project reserve amounts, for capital projects that were put into service during the five-year rolling period.	Within +/- 5% of budget excluding reserve amounts – five-year cumulative target

Appendix A: Measuring our success

Strengthen our resiliency and agility	
Performance measures supporting five-year strategy	**Targets**
Employee engagement index (% index) This is a measure of employee engagement. It is derived from a confidential survey. Results are presented based on Percent Favourable score. External benchmarks to global utilities are also provided.	At or above Global Utility Index – reporting based on survey frequency
Workforce diversity This is a measure of the diversity of BC Hydro's workforce in the representation of women, visible minorities, Indigenous people, and people with disabilities. The targets are based on available B.C. workforce in the subset of the labour market in the occupations we hire, as derived from the current census (2016).	Meet or exceed the representation in the available workforce by 2026: Indigenous people: 5% Women: 30% Visible minorities: 25% People with disabilities: 10%
Inclusion and diversity leadership training (% complete) People leaders play an important role in creating an inclusive and harassment-free workplace. This measure assesses progress against the goal of all people leaders completing the training by F24. Leadership training modules include Bias and Diversity, Safety and Inclusion, and Supporting Mental Health.	100% of people leaders trained in inclusion and diversity leadership by end of F24 and maintained thereafter on an annual basis
Training hours – Operations (average hours per Operations employee incremental to safety training) This is a measure of annual training completed by Operations employees incremental to safety training. It represents an investment in workforce capability and resiliency.	34 training hours average per Operations employee annually
Zero fatality & serious disabling injury (number of injuries) This is a measure of an incident where there has been a loss of life or an injury has resulted in a permanent disability (for which a disability pension has been received or is expected). This measure excludes contractors or public safety incidents.	Zero
Lost time injury frequency (frequency) This is a measure that shows the number of injuries resulting in lost time per 200,000 hours worked (excluding contractors). Lost time injuries are those where the employee was absent from work beyond the day of injury. **Note: This metric may be replaced by a 'leading' safety metric in future years.**	F22 – 0.76 F23 – 0.74, and maintain thereafter
Mandatory Reliability Standards violations (number of reportable violations) Measure of BC Hydro's externally reportable MRS violations.	12 or fewer violations in F26

Appendix A: Measuring our success

Advancing reconciliation with Indigenous Peoples	
Performance measures supporting five-year strategy	**Targets**
Indigenous procurement ($) This is a measure of the total dollar value of procurement at BC Hydro with Indigenous Nations across all business groups and procurement. It represents opportunities for Indigenous Nations to share in the benefits of the work that BC Hydro does to build, operate, and maintain the system.	$1 billion by the end of F26 (cumulative since 2015)
Non-integrated areas diesel reduction (%) This measure demonstrates BC Hydro's progress on reducing reliance on diesel generation in communities that are not connected to BC Hydro's integrated system.	TBD
Indigenous employment at BC Hydro (%) This is a measure of Indigenous employment at BC Hydro. It supports efforts to increase the percentage of Indigenous employees at BC Hydro with a particular focus on growing Indigenous participation in non-trade areas. (Currently 4% of BC Hydro employees are Indigenous)	25% increase from F21 baseline by end of F26
Indigenous awareness training at BC Hydro (% complete) This measure evaluates BC Hydro's workforce awareness of Indigenous issues which supports our efforts in advancing reconciliation. The measure assesses progress against employees completing INDIG-101 and/or 201 training over a five-year time period.	80% of employees trained in INDIG-101 and/or INDIG-201 by end of F26
Progressive Aboriginal Relations certification (level – external certification) This measure demonstrates BC Hydro's commitment to progressive relationships with Indigenous communities, businesses and people. BC Hydro prepares a submission once every three years outlining its approach, programs and results, examples and testimonials, and other supporting information. This submission is reviewed and evaluated by Indigenous business leaders in Ottawa where a final determination of certification level (bronze, silver, gold) is provided by an independent jury.	Gold level

Appendix B: A detailed look at the drivers behind our strategy

Our five-year strategy is designed to respond to the context we operate in, our strengths and the opportunities and challenges that lay ahead.

Key trends impacting our sector

COVID-19 AND ECONOMIC UNCERTAINTY

COVID-19 is having a significant impact on economies around the world and British Columbia is no exception. For BC Hydro, there was an unprecedented drop of nearly 10% in provincial energy demand in the months following the onset of COVID-19—twice as much as what resulted from the 2008 recession. This drop in load was largely driven by commercial and industrial customers reducing their operations.

The economic impact and load loss resulting from COVID-19 will be a challenge for BC Hydro as costs increase, load decreases, and affordability becomes more important than ever to our customers.

The trajectory and fall-out of the COVID-19 pandemic will mean unprecedented levels of uncertainty over the next five years. It'll be critical for us to use scenarios and active risk management approaches, and we'll need to maintain flexibility, leaving room to course correct in the decisions we make. Flexibility in combination with strengthened resiliency and values-based decision making are our best lines of defence during this challenging time.

Did you know?

We experienced an unprecedented drop of nearly 10% in provincial energy demand in the months following the onset of COVID-19 – twice as much as what resulted from the 2008 recession.

CLIMATE CHANGE IS TRANSFORMING THE ENERGY LANDSCAPE

Climate change is impacting the frequency and extremes of weather, precipitation and temperature events, reservoir inflow predictability, and patterns in electricity demand and supply. This has led to an increase in infrastructure damage as a result of more extreme storms, wildfires and floods.

Utilities are at the centre of plans to increase focus on low carbon electrification to displace fossil fuels and reduce greenhouse gas emissions. We're starting on strong footing here in B.C. Our investment in hydroelectricity gives us a clean energy advantage and positions B.C. as a leader over jurisdictions that rely heavily on fossil fuel generation.

TECHNOLOGIES ARE EVOLVING, AND THE COMPETITIVE LANDSCAPE IS SHIFTING

The costs of solar and wind generation and small-scale battery storage have decreased significantly, resulting in more utilities and even customers adopting these technologies. We're also seeing customers use electricity in new ways as technologies advance and electricity becomes a more prevalent fuel option in all aspects of life, from electric vehicles to more efficient space heating and cooling.

Our competitive landscape is impacted not only by competing fuel choices such as natural gas, but also by new options for self-generation of electricity by organizations and customers. Under this model, we see the role of the traditional utility shift from providing a product (energy), to providing reliability and energy management services. Rate design and price signals become important as well. This will challenge our ability to retain existing customers, while also attracting new ones.

Appendix B:
A detailed look at the drivers behind our strategy

Did you know?

British Columbia's electricity grid is part of a much larger network that includes Alberta, plus portions of 14 western U.S. states and a small part of Mexico. Power trading with these jurisdictions supports grid reliability and affordability for our customers.

TRADITIONAL LOAD PROFILE IS CHANGING

Economic drivers in B.C. are changing, resulting in many traditional power users, such as pulp and saw mills, reducing operations or shutting down. To encourage economic growth, increase demand for electricity and drive clean innovation, we must adapt to this changing economic environment, both supporting existing customers while also attracting new ones.

CUSTOMER EXPECTATIONS ARE SHIFTING

Customers today expect more from energy providers than just reliable service. They want more information, input into decisions that affect them and more ability to manage their energy use. Traditionally conservative utilities face the challenge of meeting customer expectations for customized services set by more agile and innovative industries, such as telecommunications providers. We've made progress in enhancing the customer experience by introducing tools such as access to analytics to monitor energy use and a mobile platform for our customers to interact with us. Understanding and meeting changing customer expectations will always be a focus.

GRID MODERNIZATION IS CHANGING THE WAY WE OPERATE

Smart-grid technology provides opportunities for smart and flexible end-use devices or community-based energy resources. We've made significant investments in grid modernization to date, including the introduction of smart meters, an expansive network of automatic reclosers, and new technology in the control centres. This platform puts us in a strong position to take advantage of enhanced functionality and make incremental investments in modernizing our grid. Enhanced functionality includes demand forecasting tools, distributed energy management systems, and communication and control technologies.

ELECTRICITY TRADE IS EVOLVING

We're seeing utilities in other jurisdictions rapidly increase their use of intermittent renewables, as well as system-wide interest in clean supply. As these utilities retire thermal resources, resource adequacy becomes an increasingly important issue. We already have a strategic advantage thanks to our investment in hydroelectricity, which can help with the integration of intermittent resources. Moving forward, optimizing our system flexibility and ensuring market access will be key components of our strategy to maximize trade opportunities, particularly with jurisdictions looking for clean, reliable supply.

Appendix B:
A detailed look at the drivers behind our strategy

Did you know?

The CleanBC Plan sets a target of a 40% reduction in GHGs by 2030 (from a 2007 baseline). We anticipate that policy designed to meet the 2030, 2040 and 2050 GHG reduction targets, could create significant additional demand for our clean electricity.

Our strengths

We are starting from a strong foundation. Our organization thrives on challenges. We are highly capable, experienced, and have a broad range of resources and tools at our disposal.

OUR SUPPLY OF CLEAN ELECTRICITY

We will have a surplus of electricity expected to last until the end of the decade due to the supply of electricity from our existing assets, long-term electricity purchase agreements and the clean electricity generated by Site C when it comes online in F2025. This surplus provides an opportunity to electrify additional loads, support clean growth and reduce provincial greenhouse gas (GHG) emissions, while limiting the need to develop significant generation infrastructure.

To meet this opportunity, we're not relying solely on this expected surplus. We have proven demand-side management resources at our disposal, as well as the declining cost of renewables and batteries as additional options for procuring clean and cost-effective supply.

OUR FOCUS ON EFFICIENT ENERGY USE

We're in a position to support both efficiency and electrification with customers as complementary strategies. Demand-side management can reduce overall costs for BC Hydro, provide customers bill savings opportunities and preserve flexibility, all while supporting government programs that will reduce emissions. We're also starting to promote converting existing use of fossil fuels to efficient use of clean electricity wherever possible.

OUR STRONG FINANCIAL FOOTING

Phase One of the Comprehensive Review of BC Hydro, released in 2019, included two key outcomes to keep electricity rates affordable and set BC Hydro up for future success: enhanced regulatory oversight of BC Hydro, and a new five-year rate forecast that reflects cost and revenue strategies to keep rates affordable

We worked with the government to develop a number of strategies to keep rates affordable:

- Wrote off the $1.14 billion balance in our rate smoothing account: This reduced the amount of money we need to collect from our customers and reduced pressure on rates.
- Reduced our forecast capital program by $2.7 billion over the next 10 years: We've carefully considered system impacts in this decision, and for the most part, these reductions are due to project deferrals.
- Managed the cost of energy procurement: We have worked with the provincial government to develop a new Biomass Energy program that will address the expiry of electricity purchase agreements for biomass projects in the next few years. We will acquire less energy from biomass producers at lower prices than current contracts. The Standing Offer Program was also suspended indefinitely.

Appendix B:
A detailed look at the drivers behind our strategy

Did you know?

BC Hydro has made significant progress in improving the customer experience. We receive high customer satisfaction ratings and our rates are among the most affordable in North America.

OUR FOCUS ON OUR CUSTOMERS

We exist to serve our customers and provide them with an important service they rely on every day. With a service area covering most of the province, we must take the time to understand our diverse customer base. While we won't always be able to meet every individual need, we are always better off when we listen and are open to input. We need to maintain focus in this area.

OUR STRONG, CAPABLE AND RESILIENT WORKFORCE

We have a dedicated, engaged, and highly-skilled workforce. From the front line to the office, our employees drive our day-to-day success and our ability to manage effectively through challenging circumstances, like storms or wildfires.

We're now seeing this commitment extend to the global emergency of the COVID-19 pandemic. Our team has adopted new protocols to continue safe delivery of critical services. Many employees transitioned to working remotely in a matter of days, and the entire team maintained an impressive level of effectiveness while adapting to new working circumstances.

The day-to-day work we do to deliver on our core business is getting more and more complex. We believe the flexibility and skills employees are demonstrating during the pandemic represent the type of agility we'll need to foster moving forward to be successful in our strategy, as well as our evolving sector. We also need to focus on becoming a more inclusive workplace to give our employees the space to deliver their best work.

OUR RELATIONSHIPS

High-quality relationships based on trust enable us to successfully fulfill our mandate. We recognize that building trust requires us to be open and transparent, to listen and take input, and to build upon the efforts of those who came before us. It is essential that we maintain and strengthen the relationships we have with our employees, customers, Indigenous Peoples, the public, regulators and our shareholder.

Appendix B:
A detailed look at the drivers behind our strategy

Did you know?

We have successfully entered into 13 Relationship Agreements in addition to three historic grievance agreements with Indigenous Nations. These agreements have given us a deeper understanding of the interests of Indigenous Nations so we are able to find better alignment with our business.

OUR COMMITMENT TO ADVANCING INDIGENOUS RECONCILIATION

We acknowledge the impact the development and ongoing operations of our electricity system has on Indigenous Nations. Indigenous Nations were displaced when BC Hydro flooded land for Williston reservoir, and as our infrastructure expanded across the province, so did the impacts of that infrastructure.

BC Hydro is committed to doing better. We are guided by our Statement of Indigenous Principles and have made a commitment to incorporate the United Nations Declaration of Rights of Indigenous People (UNDRIP) and the Calls to Action of the Truth and Reconciliation Commission into its business.

We've built strong relationships with Indigenous Nations and the progress we've made in this area will serve as a platform to build on moving forward. We have shifted the company to take a relationship-based approach with Indigenous Nations, particularly those where we have a significant infrastructure presence. This has led to significant growth in Indigenous procurement (over $500M in the last several years), new employment and training programs for Indigenous Peoples and an approach to environmental protection that better represents Indigenous values. Moving forward, we must continue to explore ways to bring more transparency and participation into our planning decisions by creating deeper involvement through the Integrated Resource Plan and regional plans.

OUR STEWARDSHIP ROLE IN BRITISH COLUMBIA

As a Crown corporation, BC Hydro plays a stewardship role in British Columbia that recognizes social, environmental and community objectives. Water Use Planning is an example of our broader stewardship role. When we make decisions on how to operate our hydro system we consider not just economic and electric power needs, but also what is environmentally and socially responsible. This includes valuing biodiversity for the benefit of future generations and finding a balance between uses of water such as domestic water supply, flood management, fish and wildlife, recreation, heritage and electric power needs.

We adhere to a set of environmental principles that guide our actions and decisions. Our environmental strategy is based on four key objectives: being in environmental compliance; minimizing habitat loss and fragmentation from BC Hydro projects and operations; achieving environmental benefits that also have additional value; and, supporting climate actions and targets.

Appendix B: A detailed look at the drivers behind our strategy

Did you know?

A 100% clean standard would see B.C. commit to meeting 100% of its electricity loads with clean electricity, something western U.S. states have committed to. By building on our hydroelectric base, it's possible B.C. could achieve this standard much sooner than other jurisdictions, making our province a regional leader.

OUR MARKET ACCESS AND ELECTRICITY TRADING CAPABILITIES THROUGH POWEREX

Powerex, a wholly-owned subsidiary of BC Hydro, is a leading marketer of wholesale electricity. Powerex's power marketing and trade activities help optimize BC Hydro's electricity system resources, improve the security and reliability of electricity supply for the province, and provide significant economic benefits to the people of British Columbia.

The flexibility of BC Hydro's predominantly hydroelectric generating system enables Powerex to purchase electricity from the market when prices are lower, and sell electricity to the market when prices are higher. This flexibility also enables Powerex to take advantage of differences in demand between the winter-peaking north and summer-peaking southern U.S., and between peak and off-peak periods.

Looking ahead, we need to ensure our continued participation in energy markets. Pursuing a 100% clean energy standard is one way B.C. can ensure continued market access and increase the value of our product.

OUR LEADERSHIP IN INNOVATION AND CLEAN TECHNOLOGY THROUGH POWERTECH LABS

Powertech Labs, a wholly-owned subsidiary of BC Hydro, is one of the largest and most diverse testing and research labs in North America. Powertech can leverage its team of scientists, technicians, professional engineers, researchers, and specialists to stimulate economic growth here in B.C. One way they can do this is by supporting the province's Hydrogen Strategy and increase its focus on the development of hydrogen technology and production for transportation, industry and low carbon fuel production.

Appendix B:
A detailed look at the drivers behind our strategy

The opportunities and challenges that lay ahead

We know we will face both opportunities and challenges as we implement our strategy. The following highlights what we consider to be some of these.

ACHIEVING ADEQUATE LOAD GROWTH TO UTILIZE EXISTING AND PLANNED RESOURCE CAPACITY

Growing load through efficient electricity use is fundamental to this strategy. It is the primary path that allows us to maintain affordability while managing cost pressures and making critical investments. While we cannot control external factors such as economic uncertainty, we can foster a growth mentality and ensure the tools we have at our disposal, such as rate design, and capital investment, fully support our load growth objective.

UNDERSTANDING THE DIVERSE POPULATION WE SERVE

To best serve the diverse population we interact with (employees, customers, stakeholders, Indigenous Nations, and others), we're applying Gender-Based Analysis Plus (GBA+) in our decision making to help us better understand the different impacts programs and services have on different segments of B.C.'s population. This tool will help ensure programs and services are working for all British Columbians and ensure the voices of a shifting demographic are heard and considered in decision making.

BUILDING RELATIONSHIPS THAT ADVANCE INDIGENOUS RECONCILIATION

BC Hydro plays an important role in progressing reconciliation with Indigenous Peoples in B.C. This is a time where we must continue to listen to and learn from Indigenous Peoples as we continue building this path towards reconciliation. We have been investing in building stronger relationships with Indigenous communities and we believe only by working together will we be able to achieve mutual success.

COMPLETING SITE C

Site C has been and will continue to be a challenging project. COVID-19 resulted in significant impacts to the Site C project due to the activities that were scaled back at the dam site at the onset of the pandemic. Pandemic aside, we were already managing significant financial pressures on the project, including a geological risk on the right bank. The Site C review provided 17 recommendations aimed at improving oversight and governance to ensure the project is completed safely and results in clean, reliable and affordable power for decades to come. We need to fulfill these recommendations and work together with our contractors to complete the project in the most efficient and safe way possible.

Did you know?

Gender-Based Analysis Plus (GBA+) is an analytical tool used to assess how diverse groups of people may experience policies, programs and initiatives. It examines a range of identity factors (e.g. Indigeneity, age, gender, education, language, race, ability, economic situation, etc.)

Appendix B: A detailed look at the drivers behind our strategy

Did you know?

The consequences of not meeting our compliance requirements are high.

1. It opens us up to increased risk, impacting the safety, security and reliability of our grid.
2. It hurts our reputation as a responsible utility capable of minimizing risk to the bulk electric system, and it means we lose the confidence of our regulators and utility partners.
3. It can result in hefty fines that take dollars away from programs we want and need to invest in, hurting our customers' best interests.

INCREASING EXPECTATIONS AND COMPLIANCE REQUIREMENTS

Expectations and compliance requirements are increasing in volume and complexity. Our ability to absorb cost increases is being challenged and tested by the increasing complexity of the business, particularly in areas such as critical infrastructure protection, Mandatory Reliability Standards and cybersecurity. We're also seeing an increase in service and societal expectations, along with diverse regulatory requirements from bodies such as the BC Utilities Commission and the Canada Energy Regulator. To accommodate these demands we need to find efficiencies in other areas of our business and find better approaches for rolling out new requirements.

MAINTAINING AFFORDABILITY FOR CUSTOMERS

Factors impacting affordability for customers extend beyond the cost of electricity. Our customers are facing rising costs in a range of areas and some also face other financial hardships which impact affordability. As a Crown corporation, and extension of the government, this increases pressure on us to ensure we not only provide affordable electricity, but also recognize and address the hardships some of our customers may be facing.

MAINTAINING OUR LARGE SYSTEM AND AGING INFRASTRUCTURE

One of our strengths is our flexible provincewide system of generation, transmission, and distribution infrastructure. At the same time, we remain aware that as the average age of our assets continues to grow, maintenance costs increase. These costs put pressure on our objective of maintaining affordability.

ADAPTING TO THE IMPACTS OF CLIMATE CHANGE

Climate change impacts our system and operations in many ways. From increased risk of wildfires to changes in water flows. These impacts require us to look at increasing the resilience of our infrastructure, adapting how we plan and operate the system, and being prepared to respond to severe weather events.

MANAGING ORGANIZATIONAL CAPACITY

Delivering on our mission of safely providing our customers with reliable, affordable, clean electricity is getting more challenging. The environmental factors and challenges outlined in this plan put additional pressure on our resource-constrained company. We need to get incrementally more efficient at how we do our work to better utilize our resources. This plan is intended to ensure we are targeted in where we put incremental effort.

BC Hydro
Power smart

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix E

Performance Metrics

Integrated Planning

Metrics	F23 Targets	F24 Targets	F25 Targets
Safety			
• Zero Fatality and Serious Disabling Injury – Employees (#)	0	0	0
• Lost Time Injury Frequency - Employees	0.27	0.27	0.27
• Timely Completion of Corrective Actions (%)	98%	98%	98%
• Lost Time Injury - Employees and Contractors (#)	2	2	2
Financial			
• O&M ($M)	$365.3	$372.6	$388.5
• Revenue - Interconnections ($K)	$2,330	$2,330	$2,330
• Revenue - Shared Assets and Leases ($K)	$10,462	$10,483	$10,504
Compliance			
• MRS Reported Non-Compliance Reduction Against F21 (%)	60%	70%	80%
• Mandatory Reliability Standards - Mitigation Plan Actions Completed on Time (%)	96%	97%	98%
• P1 Asbestos Actions > 90 days to complete (#)	0	0	0
• PCB Phase Out Progress (# of Units of Electrical Equipment - Excluding Streetlights)	1,080	1,090	75
People			
• Headcount Equivalent (HCE) - Active Employees Only (#)	986	988	993
• Training Hours (Excluding Safety Training) per HCE (hours)	22.0	22.0	22.0
• Engineering Utilization Rate (Based on Regular Hours) (%)	76.4%	76.6%	76.8%
Operational / Service Delivery			
• SAIDI (System Average Interruption Duration Index)	3.17	3.17	*N/A
• SAIFI (System Average Interruption Frequency Index)	1.38	1.38	*N/A
• 5-Year Rolling Average Forced Outage Factor Performance (Key Generating Stations) (%)	1.80%	1.80%	*N/A
• **Capital Delivery Management**			
o Enterprise Capital Project Write-Offs (For Deferral) ($M)	$0.0	$0.0	$0.0
o Ex-Plan Projects ($M)	N/A – Info Only		
o Ex-Plan Projects (#)	N/A – Info Only		
o Integrated Planning Project O&M ($M)	$11.3	$11.3	$11.3
o Variance Between Power System Capital Expenditure Forecast and Plan in F22 RRA Test Period (%)	± 7.5%	± 7.5%	± 7.5%
• **Customer Interconnections**			
o Interconnection Requests Received (#/MW)	N/A – Info Only		
o MW of Interconnection Projects Going into Service (#/MW)	N/A – Info Only		
o Interconnections - Studies Completed On Time (All Types) (%)	80%	80%	80%

*Target will be confirmed during the annual Service Plan process

Metrics	F23 Targets	F24 Targets	F25 Targets
• **Load Forecast Accuracy**			
o Residential Energy (Temp. Normalized GWh) (within range)	19,697 / 19,678 / 20,262	19,691 / 19,918 / 20,567	19,618 / 20,047 / 20,767
o Light Industrial and Commercial Energy (Temp. Normalized GWh) (within range)	16,893 / 18,786 / 19,673	16,779 / 18,731 / 19,716	16,656 / 18,643 / 19,724
o Large Industrial Energy (GWh) (within range)	9,511 / 13,183 / 16,570	9,476 / 14,042 / 17,874	10,358 / 14,982 / 19,984
o Total Domestic Energy for Above Three Sectors (Temp. Normalized GWh) (within range)	46,101 / 51,647 / 56,504	45,942 / 52,691 / 58,159	46,630 / 53,672 / 60,476
• **Vegetation Management**			
o Distribution Forced Outages – Vegetation Originated (%)	37%	35%	30%
o Transmission ROW Maintained (%)	20%	20%	20%

Capital Infrastructure Project Delivery

Metrics	F23 Targets	F24 Targets	F25 Targets
Safety			
• Zero Fatality & Serious Disabling Injury (#)	0	0	0
• Lost Time Injury Frequency	0.19	0.19	0.19
• Timely Completion of Corrective Actions (%)	98%	98%	98%
• Lost Time Injury - Employees and Contractors (#)	5	5	5
• Medical Attention, Treatment - Employees and Contractors (#)	9	9	9
• Near Misses - Employees & Contractors (#)	325	325	325
• Good Catches - Employees & Contractors (#)	325	325	325
• Safe Work Observations (#)	3,050	3,050	3,050
Financial			
• Operating Costs Before Capital Overhead ($M)	$84.8	$86.3	$87.6
• Capital Delivery Spend ($M)	$690.2	$807.8	$984.4
Compliance			
• MRS Reported Non-Compliance Reduction Against F21 (%)	60%	70%	80%
• Priority Environmental Incidents (#) - BC Hydro	≤14	≤14	≤14
• Project Delivery projects with PCB Removal (of last piece of equipment containing ≥43ppm PCB) at Risk of not Meeting Federal Deadline of December 31, 2025 (#)	0	0	0
People			
• Headcount Equivalent (HCE) - Active Employees Only (#)	715	715	715
• Training Hours (Excluding Safety Training) per HCE (Hours)	24.0	24.0	24.0
Operational / Service Delivery			
• Project Budget to Actual Cost: Cumulative 5-years (± 5%)	± 5.0%	± 5.0%	± 5.0%
• Performance against First Full Funding Cost: Projects ≤ Target (%)	50%	50%	50%
• Performance against First Full Funding Schedule: Projects ≤ Target (%)	50%	50%	50%
• Capital Additions All Capital Infrastructure Project Delivery ($M)	$549.1	$556.0	$731.7
• Indigenous Procurement: Contracts Committed ($M) – BC Hydro	$85.0	$50.0	$40.0
• GHG Emissions - Buildings (tCO2e) - BC Hydro	11,200	11,000	10,700
• GHG Emissions – Corporate Air Travel (tCO2e) - BC Hydro	1415	1415	1415

Operations

Metrics	F23 Targets	F24 Targets	F25 Targets
Safety			
• Zero Fatality and Serious Disabling Injury – Employees (#)	0	0	0
• Lost Time Injury Frequency - Employees	1.30	1.30	1.26
• Timely Completion of Corrective Actions (%)	98%	98%	98%
• Lost Time Injury – Employees (#)	29	29	28
• Medical Attention, Treatment – Employees (#)	34	34	33
• Lost Time Injuries and Medical Attention, Treatment – Contractors (#)	Info Only	Info Only	Info Only
Financial			
• O&M ($M)	$266.8	$269.2	$275.3
• Total Capital Delivered by Operations ($M)	$711.0	$697.0	$686.7
• Total Capital Delivered by Program and Contract Management ($M)	$451.3	$431.6	$421.7
• Total Maintenance Delivered by Operations ($M)	$266.1	$271.6	$278.3
• Total Maintenance Delivered by Program and Contract Management ($M)	$210.2	$216.6	$224.2
Compliance			
• MRS Reported Non-Compliance Reduction Against F21 (%)	60%	70%	80%
• Mandatory Reliability Standards – Mitigation Plan Actions Completed on time (%)	96%	97%	98%
People			
• Headcount Equivalent (HCE) - Active Employees Only (#)	2,607	2,613	2,632
• Training Hours (Excluding Safety Training) per HCE (Hours)	35	30	30
Operational / Service Delivery			
• SAIDI (System Average Interruption Duration Index)	3.17	3.17	*N/A
• SAIFI (System Average Interruption Frequency Index)	1.38	1.38	*N/A
• 5-Year Rolling Average Forced Outage Factor (FOF) Performance (Key Generating Stations) (%)	1.80%	1.80%	*N/A
• Connect Time Met – Express Connects (% met in 10 Days)	85%	85%	85%
• Estimated Time of Restoration (ETR) Compliance (%)	75%	75%	75%
• Estimated Time of Restoration (ETR) Accuracy (% within 60 minutes)	80%	80%	80%
• Clean Energy (%)	93%	93%	*N/A

*Target will be confirmed during the annual Service Plan process

Safety and Compliance

Metrics	F23 Targets	F24 Targets	F25 Targets
Safety			
• Zero Fatality and Serious Disabling Injury – Employees (#)	0	0	0
• Lost Time Injury Frequency - Employees	0.26	0.26	0.26
• Timely Completion of Corrective Actions (%)	98%	98%	98%
Financial			
• O&M ($M)	$65.6	$66.1	$68.0
• Capital ($M)	$4.5	$4.6	$4.1
Compliance			
• MRS Reported Non-Compliance Reduction Against F21 (%)	60%	70%	80%
• Mandatory Reliability Standards – Timely self-report submissions within 90 days (%)	100%	100%	100%
• Mandatory Reliability Standards - Completed Assurance Activities per Compliance Assurance Plan (%)	90%	93%	95%
• Mandatory Reliability Standards – Mitigation Plan Actions Completed on time (%)	96%	97%	98%
• WorkSafeBC Incident Full Investigation Deadlines Met (30 Day Deadline) (%) – BC Hydro	98%	98%	98%
People			
• Headcount Equivalent (HCE) - Active employees only (#)	374	395	412
• Training Hours (excluding safety training) per HCE (Hours)	15	15	15
Operational / Service Delivery			
• Formal Verifications Completed by Safety completed on Contractors (%)	95%	95%	95%
• Safe Work Observations Completed by Field Safety Assurance (%)	95%	95%	95%
• Compliance Checks Completed by Safety (%)	95%	95%	95%
• Safe Work Observations Completed by Safety Advocates (%)	90%	90%	90%
• Safety Advocate Compliance Checks, Non-compliances (#)	0	0	0
• Assurance reviews of established Safety programs (%)	95%	95%	95%
• Assurance review of Safety Framework completed / continual improvement actions identified (%)	100%	100%	100%
• Assurance Reviews of Emergency Management Plans Completed (%)	95%	95%	95%
• Physical Security Assurance Activity Corrective Actions Completed / Identified (%)	95%	95%	95%
• Mandatory Reliability Standards Physical Security Preventative Actions & Lessons Learned Communicated (%)	95%	95%	95%

Finance, Technology, Supply Chain

Metrics	F23 Targets	F24 Targets	F25 Targets
Safety			
• Zero Fatality & Serious Disabling Injury – Employees (#)	0	0	0
• Lost Time Injury Frequency	0.94	0.94	0.94
• Timely Completion of Corrective Actions (%)	98%	98%	98%
• Lost Time Injury - Employees (#)	7	7	7
• Medical Aid, Treatment – Employees (#)	7	7	7
Financial			
• O&M ($M)	$308.4	$314.9	$319.1
• Capital ($M)	$163.3	$132.5	$115.1
Compliance			
• MRS Reported Non-Compliance Reduction Against F21 (%)	60%	70%	80%
• Mandatory Reliability Standards - Mitigation Plan Actions Completed on Time (%)	96%	97%	98%
People			
• Headcount Equivalent (HCE) - Active Employees Only (#)	966	976	970
• Training Hours (Excluding Safety Training) per HCE (Hours)	18	18	18
Operational / Service Delivery			
• Number of Critical Priority Incidents (#) - BC Hydro	4	4	4
• Business Impact Due to Critical and High Priority Incidents (Hours) - BC Hydro	600	600	600
• GHG Emissions – Fleet (tCO2e) - BC Hydro	22,088	22,088	22,088
• Project Delivery - % Business Requirements Met for Closed Projects (YTD Reported Quarterly) (%)	90%	90%	90%
• Project Implementation Cost Met - % Closed Projects Within Budget (YTD Reported Quarterly) (%)	80%	80%	80%
Cybersecurity			
• Bitsight Security Rating - BC Hydro	Advanced	Advanced	Advanced
• BitSight Security Rating Ranking Amongst Canadian Peers - BC Hydro	Upper Quartile	Upper Quartile	Upper Quartile

Metrics	F23 Targets	F24 Targets	F25 Targets
Safety			
• Zero Fatality and Serious Disabling Injury – Employees (#)	0	0	0
• Lost Time Injury Frequency - Employees	0.17	0.17	0.17
• Timely Completion of Corrective Actions (%)	98%	98%	98%
• Lost Time Injury – Employee (#)	1	1	1
• Monthly Review of Safe Work Observations (#)	12	12	12
Finance			
• O&M ($M)	$96.6	$98.6	$100.8
• Demand Side Management (DSM) Program Spend ($M)	$83.4	$85.1	$87.1
• Low Carbon Electrification (LCE) Program Spend ($M)	$39.7	$44.1	$50.6
Compliance			
• MRS Reported Non-Compliance Reduction Against F21 (%)		N/A	
People			
• Headcount Equivalent (HCE) - Active Employees Only (#)	747	747	747
• Training Hours (Excluding Safety Training) per HCE (Hours)	20	20	20
Operational / Service Delivery			
• Communications: Favourable attitude – Monthly average (%)	65%	66%	67%
• Communications: Public confidence – Monthly average (%)	72%	74%	76%
• Social Media Channel Growth (# New Followers) (Twitter, Instagram, Facebook, LinkedIn, YouTube)	21,120	23,232	25,555
• Social Media Engagements (#)	165,000	181,500	199,650
• Energy Conservation Portfolio (New incremental GWh/year)	500	500	500
• BC Hydro Customer Satisfaction (%)- BC Hydro	85%	85%	85%
• Accounts Receivable >60 days (% of revenue)	5%	5%	5%
• Contact Centre -10+ Mins Wait Time (%)	2%	2%	2%
• Contact Centre - First Call Resolution (%)	75%	75%	75%

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix F

Electric Load Forecast Report Fiscal 2021 to Fiscal 2041

BC Hydro's Electric Load Forecast Report Fiscal 2021 to Fiscal 2041

Load Forecasting
Energy Planning & Analytics

December 2020

BC Hydro
Power smart

Executive Summary

This report provides a forecast of electricity sales to our customers and total gross system electricity requirements from fiscal 2021 to fiscal 2041. BC Hydro's load forecasts are used in a variety of business applications. In particular the December 2020 Load Forecast is being used in the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application and the 2021 Integrated Resource Plan (IRP). This report is supplemental to the information provided in those documents. Its purpose is to provide further information on the methodology and drivers underlying the forecast results.

After introducing key concepts, we describe the methodology and results of the major sector forecasts that make up the December 2020 Load Forecast, namely; Residential, Commercial, Light Industrial, and Large Industrial. These sector forecasts are followed by details on the anticipated demand from emerging demand from electric vehicles. We present the high and low forecast uncertainty bands then we discuss our peak demand forecast and Non-Integrated Area forecast.

Where possible, the report identifies Low Carbon Electrification (LCE) or fuel switching components within the load forecast which capture specific policies and measures contained in the CleanBC Plan, such as the Zero Emission Vehicles (ZEV) Act. This report also includes the results of an accelerated electrification scenario, which estimates the total demand from electrification if provincial GHG reduction targets are achieved. This work was developed by Navius Research for consideration in the IRP and the report is included as an appendix to this document.

The summary table on the following page contains the results of the December 2020 Load Forecast on a billed sales basis from fiscal 2021 to fiscal 2041. In addition to developing this reference sales forecast, we also develop a high and a low band around the reference forecast. The bands represent a range in future demands for electricity and demonstrate some of the range of uncertainty. The uncertainty bands for the December 2020 Load Forecast were generally developed by considering discrete low and high scenarios for all major sectors.

COVID-19 Pandemic

The Load Forecasting department began work on the December 2020 Load Forecast in mid-April 2020 which was still early in our understanding of how the COVID-19 pandemic would impact customer demand. The approach taken was to build on the COVID-19 scenarios that were developed in March and April 2020 and to incorporate updated information and assumptions, such as updated actual sales data and a new economic outlook from the Conference Board of Canada. Due to timing issues associated with developing up-to-date assessments of the COVID-19 pandemic's economic impacts, the Conference Board of Canada developed an economic forecast for only the Metro Vancouver area, which we extrapolated for use in our regional models.

While the December 2020 Load Forecast incorporates the estimated impacts of COVID-19 on electricity demand, considerable uncertainty remains. Determining the full impact of the pandemic to the economy (and by extension, BC Hydro's load) over the next few years will continue to be a challenge. In general, the December 2020 reference load forecast assumes the economy will return to pre-pandemic growth trends beginning in fiscal 2021, although recovery pathways will differ across various sectors. This is often described as a "K-shape" recovery. The reference load forecast also incorporates structural changes in the economy over the long term, which relate to people continuing to work or study from home. The December 2020 high forecast generally assumes COVID-19 results in no adverse impacts over the forecast period, while the low forecast assumes more adverse COVID-19 impacts relative to the reference case.

Energy Demand

The energy demand forecast captures the total consumption of energy (or sales) in a given year. In summary, our total firm sales forecast is expected to grow by an average of 1.1 per cent per year over the next twenty years, after adjusting for rate impacts and

Demand-Side Management Savings (DSM)[1]. Most of this growth is due to increased demand in oil and gas and Liquified Natural Gas (LNG) in the Large Industrial Sector and demand from light duty Electric Vehicles which is included in our Residential and Commercial Load Forecasts. Forecast values are provided in Table 1.

Peak Demand

The peak demand forecast estimates the highest consumption of electricity in a one-hour period over the course of a year. The peak forecast closely follows the growth pattern of the energy forecast., with the following exceptions:

a) Distribution peak (which is comprised of residential, commercial, and light industrial sectors) has a higher contribution to the time of the system peak than transmission peak (large industrial sector). This results in the distribution peak representing a larger share of the total peak forecast in comparison to the energy forecast.

b) The Electric Vehicle forecasts have a proportionally higher impact on peak demand than energy due to charging profile assumptions.

Table 2 shows the twenty-year forecast for the major components of the peak forecast.

[1] The DSM plan used in the December 2020 Load Forecast was approved in the Fiscal 2022 to Fiscal 2024 Annual Business Plan. It does not include any potential recommended actions from the 2021 Integrated Resource Plan.

Table 1 – December 2020 Energy Load Forecast after Adjustments for Rate Impacts and Demand-Side Management

	Major Customer Sectors					Other Loads			Total Domestic Sales		
Fiscal Year	Residential	Commercial	Light Industrial	Light Industrial & Commercial	Large Industrial	Irrigation & Street Lights	Inter Utility Sales to City of New Westminster & FortisBC Electric	Total Firm Export Sales to Seattle City Light & Hyder Alaska	Total Domestic Sales - Reference	Low Domestic Sales	High Domestic Sales
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)
Temperature Normalized Actuals											
F2015	17,973	14,460	4,227	18,687	14,055	296	966	306	52,283	52,283	52,283
F2016	18,019	14,257	4,148	18,405	13,698	322	971	309	51,724	51,724	51,724
F2017	17,952	14,582	4,275	18,856	13,106	312	1,053	319	51,599	51,599	51,599
F2018	17,997	14,513	4,364	18,877	13,513	308	1,017	313	52,025	52,025	52,025
F2019	17,876	14,557	4,422	18,979	13,766	304	897	309	52,131	52,131	52,131
F2020	18,349	14,336	4,311	18,648	13,236	285	1,049	312	51,878	51,878	51,878
Forecast											
F2021	19,799	12,864	4,326	17,190	12,165	313	1,224	311	51,002	49,093	53,185
F2022	19,789	13,654	4,628	18,282	12,437	306	1,129	313	52,256	48,060	55,761
F2023	19,678	13,968	4,825	18,794	13,183	295	1,124	311	53,384	47,838	58,243
F2024	19,892	13,921	4,810	18,730	14,042	290	1,127	311	54,393	47,646	59,857
F2025	20,033	13,820	4,825	18,645	14,982	290	1,153	311	55,414	48,374	62,216
F2026	20,250	13,774	4,841	18,615	15,896	291	1,148	313	56,513	48,122	64,914
F2027	20,494	13,723	4,867	18,590	16,335	291	1,234	311	57,255	48,064	67,957
F2028	20,809	13,698	4,896	18,594	16,741	292	1,252	311	57,999	48,010	70,110
F2029	21,112	13,655	4,913	18,568	16,745	292	1,286	311	58,314	47,069	73,039
F2030	21,458	13,627	4,917	18,544	16,757	292	1,314	313	58,678	47,006	73,921
F2031	21,812	13,598	4,935	18,533	16,754	292	1,363	311	59,065	46,971	74,737
F2032	22,215	13,580	4,952	18,532	16,828	293	1,398	311	59,577	46,956	75,387
F2033	22,593	13,556	4,977	18,533	16,791	293	1,432	311	59,953	46,956	75,959
F2034	23,019	13,544	5,006	18,551	16,759	293	1,468	313	60,402	46,991	76,680
F2035	23,460	13,537	5,037	18,573	16,727	294	1,512	311	60,878	47,032	77,402
F2036	23,948	13,543	5,071	18,613	16,690	294	1,543	311	61,400	47,068	78,232
F2037	24,379	13,536	5,101	18,637	16,645	294	1,553	311	61,819	47,072	78,948
F2038	24,852	13,543	5,134	18,677	16,608	294	1,564	313	62,308	47,133	79,729
F2039	25,328	13,543	5,172	18,715	16,577	295	1,567	311	62,793	47,197	80,493
F2040	25,833	13,558	5,215	18,773	16,543	295	1,574	311	63,329	47,301	81,318
F2041	26,360	13,605	5,279	18,884	16,575	295	1,605	311	64,030	47,608	82,266
Compound Annual Growth Rates											
5-year History CAGR (F15 - F20)	0.4%	(0.2%)	0.4%	(0.0%)	(1.2%)	(0.8%)	1.7%	0.4%	(0.2%)	(0.2%)	(0.2%)
5-year CAGR (F20 -F25)	1.8%	(0.7%)	2.3%	(0.0%)	2.5%	0.3%	1.9%	(0.1%)	1.3%	(1.4%)	3.7%
10-year CAGR (F20 - F30)	1.6%	(0.5%)	1.3%	(0.1%)	2.4%	0.2%	2.3%	0.0%	1.2%	(1.0%)	3.6%
20-year CAGR (F20 - F40)	1.7%	(0.3%)	1.0%	0.0%	1.1%	0.2%	2.0%	(0.0%)	1.0%	(0.5%)	2.3%

Table 1 Notes

1. All forecast values include all adjustments for LCE/fuel switching, rate impacts, Demand-Side Management savings, and voltage-ampere reactive and voltage optimization (VVO) savings.
2. Light Industrial/Commercial is the sum of the loads in the light industrial sector and commercial sectors.
3. Total Domestic Sales is the sum of the loads from the Main Customer Sectors and Other Loads. BC Hydro own use is not included.

Table 2 - December 2020 Peak Forecast - After Rate Impacts and After Demand-Side Management

Fiscal year	Coincident Distribution (MW)	Coincident Transmission (MW)	Other Utilities (MW)	Transmission Losses (MW)	Total Integrated System Peak (MW)	Low Integrated Peak Forecast (MW)	Ref Integrated Peak Forecast (MW)	High Integrated Peak Forecast (MW)
Temperature normalized actuals								
F2020	8,005	1,440	384	642	10,471	10,471	10,471	10,471
Forecast								
F2021	7,793	1,468	471	673	10,405	10,163	10,405	10,799
F2022	8,047	1,474	472	691	10,684	10,049	10,684	11,182
F2023	8,169	1,543	471	704	10,887	10,023	10,887	11,571
F2024	8,217	1,644	473	707	11,041	10,011	11,041	11,867
F2025	8,243	1,746	474	710	11,173	9,983	11,173	12,260
F2026	8,318	1,797	475	716	11,307	9,945	11,307	12,592
F2027	8,395	1,844	476	724	11,439	9,907	11,439	13,119
F2028	8,482	1,866	478	731	11,557	9,880	11,557	13,402
F2029	8,575	1,868	479	737	11,660	9,780	11,660	13,918
F2030	8,674	1,869	481	744	11,768	9,760	11,768	14,156
F2031	8,782	1,865	482	752	11,881	9,743	11,881	14,399
F2032	8,902	1,872	484	761	12,018	9,726	12,018	14,645
F2033	9,027	1,871	485	769	12,152	9,724	12,152	14,902
F2034	9,156	1,868	486	778	12,288	9,712	12,288	15,159
F2035	9,293	1,864	488	788	12,433	9,702	12,433	15,442
F2036	9,441	1,861	490	798	12,589	9,689	12,589	15,740
F2037	9,587	1,857	491	808	12,743	9,688	12,743	16,032
F2038	9,734	1,854	492	818	12,898	9,685	12,898	16,316
F2039	9,880	1,851	494	828	13,053	9,686	13,053	16,591
F2040	10,023	1,848	496	838	13,204	9,680	13,204	16,853
F2041	10,181	1,849	497	849	13,376	9,704	13,376	17,127
Compound Annual Growth Rates								
5-year CAGR (F20 to F25)	0.6%	3.9%	4.3%	2.0%	1.3%	-1.0%	1.3%	3.2%
10-year CAGR (F20 to F31)	0.8%	2.4%	2.1%	1.4%	1.2%	-0.7%	1.2%	2.9%
20-year CAGR (F20 to F41)	1.2%	1.2%	1.2%	1.3%	1.2%	-0.4%	1.2%	2.4%

Table of Contents

1.0 Introduction

BC Hydro is the third largest utility in Canada and serves 95 per cent of British Columbia's population. BC Hydro's total energy requirements, including losses and sales to other utilities and non-integrated areas (NIAs), were 57,003 GWh in fiscal 2020. Excluding the NIAs, the total integrated system energy requirements were 56,663 GWh.

Load forecasting is central to BC Hydro's long-term planning, medium-term investments, and short-term operational & forecasting activities. BC Hydro's Electric Load Forecast is used to provide decision-making information for electricity rates, as well as where, when, and how much electricity we expect to need from the BC Hydro system. About two thirds of the forecast is based on Statistically Adjusted End Use (SAE) econometric (regression) models that use historical billed sales data combined with economic forecasts and inputs from internal, government and third-party sources. The other one third of the forecast is derived from individual forecasts of our large industrial customers.

BC Hydro's load forecasting activities include the preparation of a number of time and location specific forecasts before and after certain adjustments in order to provide information for decision makers.

In developing the reference load forecast, BC Hydro evaluates the impact of public policy commitments such as the CleanBC plan based on the legislation, regulations and funding in place to achieve the policy's stated objectives. The December 2020 reference load forecast incorporates legislative and policy measures related to CleanBC that were already in place or were close to being enacted, giving them a higher degree of certainty. For example:

- Light duty electric vehicle (EV) load - The CleanBC Plan made a firm commitment to a Zero Electric Vehicle (ZEV) mandate that was enacted in legislation on May 20, 2019. Accordingly, the EV forecast is included in the Load Forecast.
- BC Government-Funded Fuel Switching – The impact of the fuel switching component of the government-funded CleanBC Better Buildings/Homes program, which BC Hydro is administering on behalf of the Government of B.C, is captured in the Load Forecast.
- BC Hydro Low Carbon Electrification (LCE) – BC Hydro's Low Carbon Electrification (LCE) projects/programs, described in Appendix N of the Fiscal 2022 Revenue Requirements Application, support CleanBC strategies.
- Large Industrial Electrification. The CleanBC Plan includes providing clean electricity supply to natural gas production in the Peace region and increasing access to clean electricity for large operations with new transmission lines and interconnectivity to existing lines. Accordingly, forecast load growth from specific projects in the oil and gas (including LNG) sub-sector is included in the Load Forecast and in our estimate of electrification-related loads.

Where possible, specific load forecast components that are also captured in the Clean BC plan, such as the examples listed above, will be identified and quantified in this document. However, its important to note the December 2020 Load Forecast is a comprehensive load forecast encompassing updates to many inputs and model calibration periods. Accordingly, for many of the load forecast components it is not practical to precisely isolate specific quantitative impacts of the CleanBC policy measures from other changes between load forecast vintages.

BC Hydro has been supporting electrification and greenhouse gas emission reductions for a number of years. In August 2020 BC Hydro initiated work to develop an Electrification Plan designed to consolidate the actions already underway as well as new actions to increase low carbon electrification, attract additional load, and connect customers more efficiently. Electrification from fuel switching helps to achieve provincial greenhouse gas targets, while new customer load not tied to fuel switching aids provincial economic growth, and both help to keep rates affordable while BC Hydro is in an energy surplus situation.

The December 2020 Load Forecast was finalized prior to the Electrification Plan. Because the Electrification Plan consolidates actions already underway, some plan components such as the CleanBC-driven measures described above are reflected in the December 2020

Load Forecast. Additional components and revised estimates for the existing components will be incorporated into future load forecasts.

The assumptions used in the December 2020 Load Forecast are reasonable for use in the Revenue Requirements Application, given the duration of the test period. For long-term planning purposes, the December 2020 Load Forecast is supplemented with additional scenario that inform contingency plans preparing BC Hydro to meet the demand anticipated from British Columbia achieving its legislated climate change greenhouse gas reduction targets on schedule. More information on this scenario is outlined in this report and a detailed summary is provided as Appendix F to this report.

BC Hydro develops an electricity sales forecast for each of its main customer sectors including residential, commercial, light industrial, and large industrial. We also develop a forecast of electricity sales to other utilities and firm exports supplied by BC Hydro. The methodology used for each sector, as well those for other utilities and firm exports, are the focus of this report.

In addition to the reference forecast, we develop high and low uncertainty bands which represent ranges around the reference forecast. These high and low uncertainty bands are produced because there is uncertainty in the input variables that predict future loads and in the predictive capabilities of the forecasting models themselves. The December 2020 Load Forecast also includes an accelerated electrification scenario which was developed for consideration in the 2021 Integrated Resource Plan. To complete this work, BC Hydro retained Navius Research to estimate the electricity demand impact using models and an analytical approach similar to that used by the BC Government's Climate Action Secretariat in developing the CleanBC Plan. The accelerated electrification scenario presents the estimated impact on load growth if provincial GHG reduction targets are consistently met over the milestone years of 2025, 2030 and 2040. The scenario estimates the demand over and above BC Hydro's December 2020 reference load forecast, and the analysis reflects the incremental need for electricity that could be expected relative to that load forecast.

The next section provides an overview of the components and steps involved in developing our total integrated gross system requirements forecast.

Finally, detailed information is available in the appendices to this report. The appendices include:

- comparison of the December 2020 Load Forecast to March 2020 Load Forecast and COVID-19 Scenarios,
- a description of the SAE models and equations,
- a description of the temperature normalization process,
- peak demand forecast methodology,
- the Conference Board of Canada's "B.C. Economic Outlook 2020" used in preparation of this load forecast,
- the Navius electrification report, and
- summary tables containing the December 2020 Load Forecast,

2.0 Load Forecast Components

The load forecast is comprised of many components which come together in various ways to compile forecasts used for different purposes. This section describes the different components and combinations.

2.1 BUILD UP OF TOTAL INTEGRATED GROSS SYSTEM REQUIREMENTS

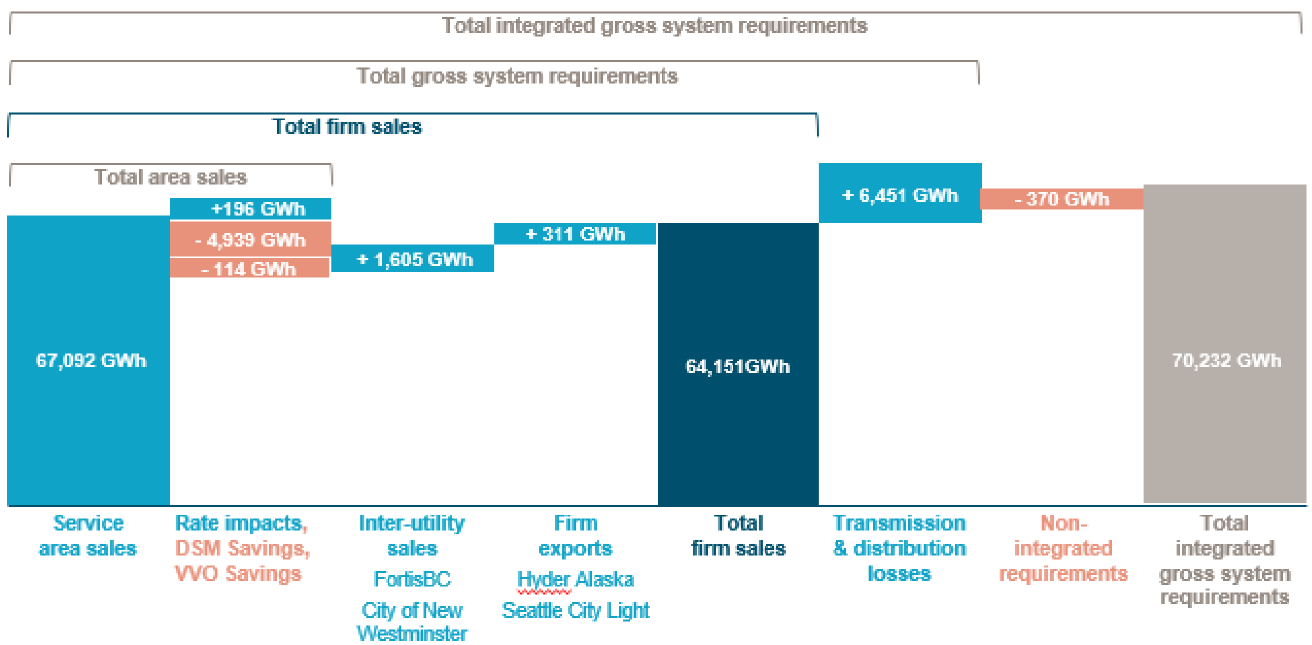
The highest level of our forecast is called total integrated gross system requirements. It is used to optimize operations of our system in the short-term and to plan our system over the long-term. For short-term analysis, the forecast is used by BC Hydro's Generation System Operations business unit in monthly energy studies.

The forecast of BC Hydro's total gross system requirements is built up from a series of components and steps, including:

- A forecast of electricity sales to all customers in our service area (service area sales). This includes a forecast for our main customer sectors (i.e., residential, commercial, light industrial and large industrial) and other loads including street lighting customers, irrigation customers, and electricity used by BC Hydro assets, such as distribution substations. We refer to this BC Hydro asset-related consumption as BC Hydro own use,
- A forecast of electricity sales to other utilities supplied by BC Hydro under contracts and tariffs. Service area sales plus sales to other utilities results in total firm sales, and
- A forecast of system distribution and transmission losses (i.e., total losses). Total firm sales and total losses results in total gross system requirements.

Figure 2.1 illustrates the build-up of our forecast of total gross system requirements and integrated total gross system requirements based on one of the three forecast types, namely: after considering rate impacts and savings associated with our Demand-Side Management (DSM) plan and voltage-ampere reactive and voltage optimization (VVO) savings.

Figure 2-1 Build-up of Total Integrated Gross System Requirements Forecast after Rate Impacts, DSM and VVO Savings for Fiscal 2041



The loads used to develop each of the major components of total integrated gross system requirements are summarized in the following sections.

2.1.1 Service Area Sales

The service area sales forecast includes the forecast for our main customer sectors (i.e., residential, commercial, light industrial, large industrial, etc.). Developing these forecasts is a detailed process which involves a number of different forecasting models.

Table 2.1 below shows that service area sales are the sum of our individual model projections plus load additions.

Table 2-1 – Summary of Model Projections and Load Additions Which Make Up Service Area Sales

Service Area Sales =	Model Projections	+ Load Additions			
Major Sector	**Model Description**	**Electric Vehicles**	**Codes & Standards Overlap**	**Low Carbon Electrification / Fuel Switching**	**Estimated DSM Persistence Drop Off**
tResidential	Accounts forecast x use per account forecast (from 4 SAE models)	85% of light duty EV forecast	**Yes**	**Yes**	N/A
Commercial	Sales forecast (from 8 SAE models)	15% of light duty EV forecast	**Yes**	**Yes**	N/A
Light Industrial	Sub-sector models and individual customer forecasts, plus construction loads	N/A	N/A	**Yes**	N/A
Large Industrial	Sub-sector forecasts by customer	N/A	N/A	**Yes**	**Yes**
Other Elements	Individual trend analysis models for Irrigation, Street Lighting, an BC Hydro own use	N/A	N/A	No	N/A

A description of each of these components is provided below.

2.1.1.1 Model Projections are Used for Each Major Customer Sector

Model projections are forecasts for our main customer sectors: residential, commercial, light industrial, and large industrial. These are laid out in the following sections of this document:

- Section 3 outlines our projections of electricity sales to the residential sector,
- Section 4 outlines our projections of electricity sales to the commercial sector,
- Section 5 outlines our projections of electricity sales to the light industrial sector, and
- Section 6 outlines our projection of electricity sales to the large industrial sector.

2.1.1.2 Load Additions are Added to Major Customer Sectors

In addition to our model projections, unique customer segments and technologies or adjustments are also included in our customer sector forecasts. A description of each load addition follows.

2.1.1.2.1 Electric Vehicles

A forecast of light duty electric vehicle load is included in our residential and commercial sector forecasts. A description of forecast methodology and results are outlined in Section 7. We are developing and implementing a new Electric Vehicle model, which expands the forecasting capability to also include medium and heavy duty vehicles. Results will be incorporated into future load forecasts when the model is available and testing of the model is complete.

Load from the light duy EV model is allocated to the residential and commercial sectors at 85 per centand 15 per cent is added to the respectively.

2.1.1.2.2 Codes and Standards Overlap

Codes and standards are minimum end-use efficiency requirements that come into effect in a jurisdiction, and that are enabled by legislation or by regulation of manufacturers. U.S. based codes and standards are reflected in the average stock efficiency forecast of residential and commercial end uses of electricity. The average stock efficiency forecasts are produced by the U.S. Energy Information Administration (EIA). The EIA efficiency forecast is one of the main inputs of the residential and commercial SAE models and the forecasts from these models are the starting point for the load forecasts for these sectors.

BC Hydro's DSM plan also includes savings that can be achieved through government policy instruments such as codes and standards that influence the use of energy and target similar end uses as those represented in the EIA efficiency forecast data. As such, there is a potential for overlap in efficiency requirements for end uses of electricity that are enabled from codes and standards as modelled by EIA assumptions and our DSM plan.

The EIA assumes that no new legislation or regulations fostering efficiency improvements beyond those currently embodied in l aw or government programs will take place over the forecast horizon. These efficiency level assumptions are documented by the EIA in the annual energy outlook. BC Hydro has reviewed the EIA's documentation on minimum efficiency standards on end use of electricity and technologies and compared those to the efficiency standards of end use electricity and technologies contained in our DSM plan. Using this information, BC Hydro was able to determine where there were overlaps in codes and standards on various residential and commercial end uses of electricity and technologies.

Some examples of overlap in codes and standards for the residential sector are lighting, dishwashers, stand-by power, TVs, freezers, refrigerators and clothes washers. For the commercial sector some examples include lighting, large clothes washers, walk in coolers, large refrigerators, air conditioning, packaged terminal air conditioning, and dry transformers.

After the areas where overlap are determined, an adjustment is made to account for the overlap in codes and standards. The adjustment is applied to the SAE models' projections to mitigate potential double counting by using an estimate of the overlap between EIA assumptions reflected in our models and codes and standards that result in electricity savings which are contained in our DSM plan.

Load adjustments for overlap in codes and standards, including lighting, have been in place since our 2010 Load Forecast. In 2019, Navigant Inc. completed an independent review of the overlap in codes and standards in the EIA projections with those within BC Hydro's DSM plan. The review determined that there were some end use technologies that appeared in both the SAE model (i.e., EIA based end use efficiencies) and the DSM plan. Accordingly, the December 2020 Load Forecast has been adjusted to improve alignment with this review.

For the non-lighting code items that were considered to be an overlap, BC Hydro applied 50 per cent of the forecast of DSM savings of these various codes and standards which overlapped with the EIA. The 50 per cent assumption is a high-level estimate because there are a number of uncertainties, we were not able to address as part of our evaluation. These uncertainties include the following:

- There are differences in timing between our service area relative to the geographic areas incorporated in the EIA model (Pacific region) on when the various code and standards come into place,
- There are differences in end uses and technology modelled in the DSM plan and those modelled in the EIA. For example, in the area of refrigeration, not all of the same types of refrigerators are modelled from the same starting point on efficiency and types of various refrigerators. There may also be differences in compliance rates between our service area relative to what is assumed in the EIA model,
- The EIA model only includes the impacts of past U.S, legislation and regulations and does not include future codes and standards. Our DSM plan includes savings from future regulations that are planned and announced , and
- Using the savings from the DSM plan as the basis to determine the impact of the overlap of codes and standards on our load forecast is at best a proxy estimate.

For lighting codes and standards, where there is also overlap for various lighting technologies (i.e., different types of a light bulbs), we have left the base year (i.e. 2020) efficiency level of indoor and outdoor lighting as provided by the EIA unchanged over the forecast period. This method for lighting was chosen to provide consistency with previous forecasts that had already identified an overlap with lighting codes and standards.

We continue to assess the extent of the overlap over the various diverse set of electrical appliances and uses of electricity as part of our continuous improvement efforts. Further work in this area may lead to revised overlap projections.

2.1.1.2.3 Low Carbon Electrification (LCE) / Fuel Switching

Low Carbon Electrification (LCE) refers to actions that encourage the use of electricity for the purposes of reducing greenhouse gas emissions. Similarly, fuel switching refers to the customer choosing electricity over a feasible fossil fuel alternative. In our load forecasting process we add estimated loads related to LCE and fuel switching to capture the following:

1) BC Hydro's Low Carbon Electrification (LCE) projects and programs; and
2) The impact of the fuel switching component of the government funded CleanBC Better Buildings/Homes program, which BC Hydro is administering on behalf of the Government of B.C.

Throughout this document the load additions related to the above load additions are referred to as LCE/fuel switching.

It should be noted that some fuel switching loads are also imbedded in the forecast for certain large industrial customers who have undertaken projects to use electricity in lieu of fossil fuel alternatives. These are captured in the large industrial forecast and not included in this load addition. Further details are provided in sections 6 and 8.2.6 of this report.

2.1.1.2.4 Estimated DSM Persistence Drop Off

In developing the large industrial load forecast, we have included the estimated DSM persistence drop off in each of the large industrial sub-sectors based on analysis by our Conservation and Energy Management group. We now assume that once an efficiency project has been implemented, the customer will continue to replace like for like equipment at the end of its lifecycle.

2.1.2 Adjustments for Rate Impacts, DSM Savings, and VVO Savings

Service area loads are adjusted to account for rate impacts, Demand-Side Management savings, and VVO energy savings.

2.1.2.1.1 Rate Impacts

Load reductions that result from rate impacts are calculated separately for each of our main sectors. Rate impacts are based on:

- an electricity price elasticity of -0.1 applied to the major sectors including residential, light industrial, commercial, and customers that make up the large industrial sector, and

- a projection of bill impacts informed by the forecast underlying the Fiscal 2022 Revenue Requirements Application which covers fiscal 2021 to fiscal 2026, with bill impacts beyond fiscal 2026 equal to an assumed annual inflation rate of two per cent.

2.1.2.1.2 Demand-Side Management (DSM) Savings

The incremental savings from our DSM plan are computed separately for each customer sector and at the BC Hydro service area level. The forecast of DSM savings reflected in our December 2020 Load Forecast is based on a DSM plan which included updated information to reflect COVID-19 impacts. DSM savings from fiscal 2021 to fiscal 2041 are based on incremental activities to the fiscal 2020 base year, which was the last year of actual sales. The DSM plan used in the December 2020 Load Forecast was approved in the Fiscal 2022 to Fiscal 2024 Annual Business Plan. It does not include any potential recommended actions from th e 2021 Integrated Resource Plan.

BC Hydro's DSM plan is comprised of initiatives that have the objective of reducing customers' energy consumption and by doing so, reducing their electricity bills. The main components of BC Hydro's DSM plan are:

- Programs: Programs are available to all customer sectors and deliver a mix of information, access to technology and services, technical assessment and support, and financial assistance to all customer classes to address barriers to cost effective Demand-Side Management. Programs are designed to capture additional Demand-Side Management potential that remains beyond that obtained from codes and standards and rate structures.
- Codes and Standards: Codes and standards refer to a range of government policy instruments that influence the use of energy, including product/equipment regulations, building codes and tax measures. BC Hydro supports the development of these codes and standards and works with communities on municipal zoning/building permitting processes, as well as enhanced approaches for Indigenous and remote communities.
- Rates: Rate structures are changes to the design of electricity rates to provide more economically efficient price signals to customers which encourage conservation. BC Hydro currently has conservation rate structures in place for residential and large industrial (transmission voltage) customers.
- Supporting Initiatives: Supporting initiatives include public engagement and awareness activities and general management and infrastructure.

2.1.2.1.3 VVO Savings

VVO savings refer to volt-ampere reactive and voltage optimization (VVO) energy savings at our distribution substations.

VVO is a strategic initiative focused on realizing financial value to BC Hydro and its distribution customers.

VVO is an industry-recognized practice of optimizing the distribution-supply voltage for distribution customers to realize a reduction in energy consumption (i.e., energy savings). In other words, VVO is a way of reducing energy consumption, and its focus is not to reduce line losses. By reducing energy consumption for distribution customers, BC Hydro can reduce the amount of energy it needs to supply (i.e., produce or purchase), resulting in financial benefits for BC Hydro, lower energy rates and energy bills for its customers. From the customer's perspective, the customer realizes a financial benefit because they receive lower rates, consume less energy, and therefore, have lower energy bills.

The principle underlying the VVO application is that when VVO is enabled at a substation, distribution supply voltage is optimized (i.e., reduced) to the lower-end of the acceptable operating voltage range for the voltage critical distribution customers - as voltage is reduced, distribution-voltage customers could draw less power and consume less energy than they would otherwise do so if VVO was not enabled.

The projected VVO energy savings are estimated and incorporated into the energy load forecast. The forecast of VVO savings is developed for our distribution system and is also incremental to the fiscal 2020 base year. VVO savings are applied to residential, light industrial and commercial sectors on load share basis

2.1.2.2 Other Elements of Service Area Sales

Forecasts for other small loads such as irrigation customers, street light customers, and BC Hydro's own use are developed separately, and these forecasts are included as part of our total area sales. With the exception of BC Hydro own use, all of these loads are developed with trend analysis. The forecast of BC Hydro own use is developed with trend analysis for the base load and supplemented with additional construction load for the Site C Project. The construction loads are based on estimates provided to BC Hydro from the various contractors involved in the construction of the Site C Project. The details of the trend analysis and forecast results for these other loads are not covered in this report.

2.1.2.3 Inter-Utility Sales and Firm Exports

The next component represented in Figure 2-1 includes sales to the City of New Westminster and FortisBC Electric. Sales to these two utilities make up total inter-utility sales. Sales to Seattle City Light and Hyder, Alaska make up total firm exports. Rate impacts using the same price elasticity and bill impact projections as described above are applied to loads from the City of New Westminster and Hyder, Alaska. Sales to Seattle City Light are determined by a treaty and as such rate impacts are not applied. For sales to FortisBC Electric, rate impacts are built into a methodology that determines the electricity sales. That methodology and the forecasted inter-utilities sales and firm exports are detailed in Section 8. The combined forecast of inter-utilities sales, firm exports, and total area sales is the forecast of total firm sales.

2.1.2.4 Transmission and Distribution Losses

When electricity is moved from one location to another, losses occur. To account for this, transmission and distribution losses are estimated by applying loss factors to the individual loads that make up total firm sales. The estimated losses are added to the total firm sales to calculate total gross system requirements, as shown in Figure 2-1.

2.1.2.5 Non-Integrated Area Requirements

The Non-Integrated Areas (NIA) consist of a number of small communities located in parts of B.C. not connected to BC Hydro's integrated transmission grid. Further details on these areas is provided in Section 11.

2.1.2.6 Total Integrated Gross System Requirements

Finally, total integrated gross system requirements are calculated by reducing total gross system requirements by the sales and losses from loads in our Non-Integrated Areas.

2.2 TYPES OF FORECASTS

Different types of forecasts are produced to serve different needs within BC Hydro and to meet requirements set out by the BC Utilities Commission (BCUC).

2.2.1 BCUC Required Forecasts

Following the BCUC Resource Planning Guidelines, BC Hydro develops three types of forecasts:

- before considering rate impacts, Demand-Side Management and VVO savings,
- after considering rate impacts, but before Demand-Side Management and VVO savings, and
- after considering rate impacts, Demand-Side Management and VVO savings.

These forecast types allow us to identify the specific effects associated with future electricity price (rate) changes and Demand-Side Management savings. Each type is calculated for each of the forecast components outlined previously in Section 2.1.

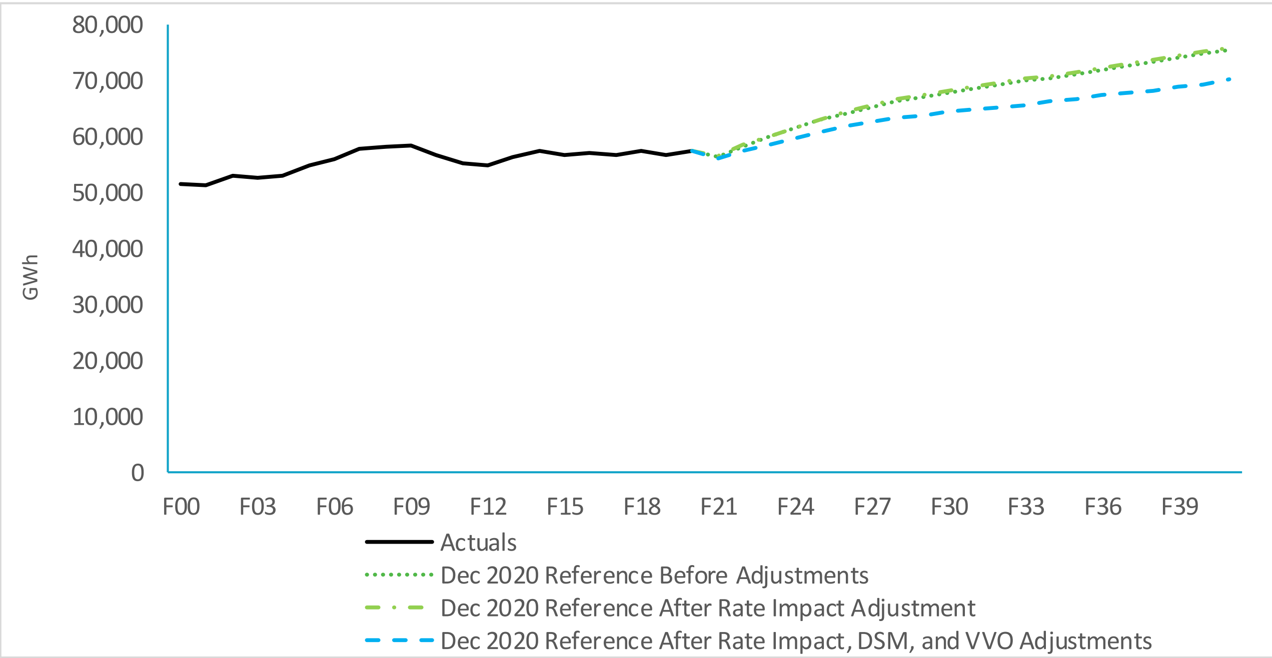
For example, we have three forecasts of total firm sales:

- the reference forecast of total firm sales before rate impacts includes all model projections for main sectors, load additions, forecasts for irrigation customers, streetlights customers, BC Hydro own use, and sales to inter-utilities and firm exports,
- the reference forecast of total firm sales after rate impacts includes the estimated effects of rate impacts, and
- the reference forecast of total firm sales after Demand-Side Management and VVO savings is the same as total firm sales after rate impacts but also includes load reductions for Demand-Side Management and VVO.

This convention for naming the three types of forecasts is used through the rest of the document.

Figure 2-2 below is provided to illustrate these three types of forecasts.

Figure 2-2 – December 2020 Reference Load Forecast Total Integrated Gross System Requirements Before and After Adjustments



As shown in Figure 2-2 the rates adjustment has a minor effect on the overall forecast while the DSM impact is more significant and serves to reduce load by an increasing amount over time.

When each of the other forecast components is calculated in the same three ways, they can be combined to make up three types of total gross system requirement and integrated gross system requirements, and the results for these forecasts are summarized in tables contained in Appendix G of this report.

2.2.2 Billed and Accrued Sales Forecasts

Our forecasts are based on relationships between load drivers and billed sales. As such, the forecast of future customer loads is in the form of billed sales projections. In our revenue requirements applications, accrued sales projections are derived from the billed sales forecasts. In general terms, billed sales represent what was billed to our customers in a month or over a fiscal year in line with our billing cycle, which may span several months. Accrued sales represent the electricity consumed during a calendar month, which involves accruals of an estimate of the unbilled sales in that month, in accordance with accounting standards.

2.2.3 Forecasts to Characterize Uncertainties

To quantify the various uncertainties in the factors that increase or decrease load, BC Hydro develops a high and a low uncertainty band around our reference forecast. The details of our uncertainty band process are contained in Section 8 of this report.

3.0 Residential Forecast

3.1 RESIDENTIAL SECTOR DESCRIPTION

At the end of fiscal 2020, there were almost 1.9 million residential accounts served by BC Hydro and electricity sales were 18,349 GWh. This represents about 35 per cent of BC Hydro's total firm sales on a billed basis. Residential customers use electricity for a variety of what we call "end-uses." These include space heating, cooling, lighting, water heating, cooking, refrigeration, and other plug-in loads which include computer equipment and home entertainment systems. Since space heating and cooling loads are dependent on the outside temperature, residential sales can be affected by temperature. As such, our forecasting process, like most utilities, develops a residential sales forecast based on a historical rolling average of temperatures over the past 10 years, or also referred to as a "temperature normalized basis." More information on temperature normalization is available in Appendix C of this report.

BC Hydro has four main service regions. In fiscal 2020 electricity use across these regions as a percentage of total residential sales was:

- Lower Mainland 54 per cent,
- Vancouver Island 25 per cent,
- South Interior 13 per cent, and
- North Region[2] eight per cent.

Historical trends in our residential sector include:

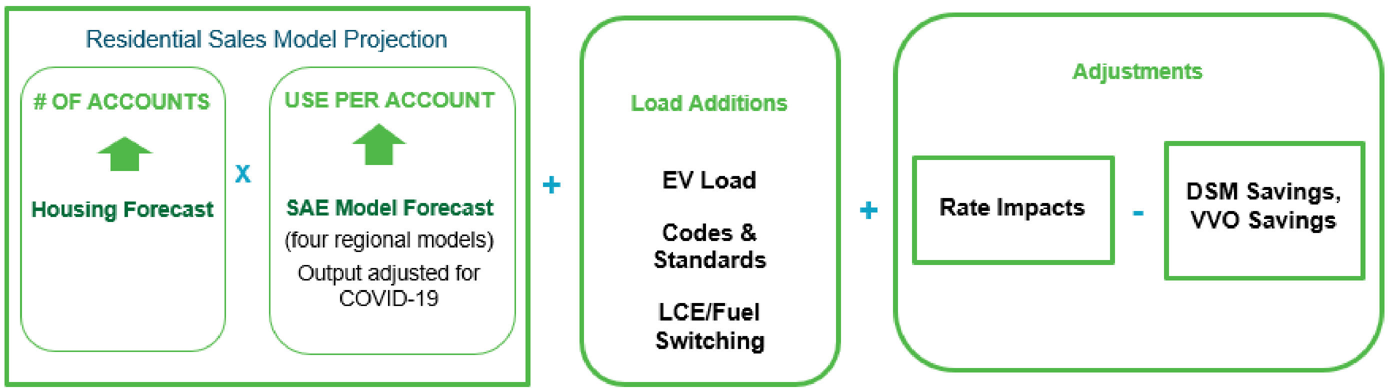
- strong historical growth in accounts which have increased an average of approximately 27,000 accounts per year over the past five years ending fiscal 2020,
- a movement to denser multiple housing units, and
- a decline in the average use per account.

3.2 RESIDENTIAL FORECAST METHODOLOGY

Figure 3-1 below shows our residential forecasting process and the build-up of the Residential Reference Load Forecast.

[2] The North Region includes customers connected to our integrated grid and those in our non-integrated areas. More information on the Non-Integrated Areas forecast is provided in Section 3.2.

Figure 3-1 Residential Reference Load Forecast Build-up



The equation used to develop the residential sales model projection, represented in the left side of Figure 3-1, is:

Equation 3-1

$$\begin{aligned}&\mathit{Residential\ Sales\ Regional\ Model\ Projection}\\&= \mathit{Number\ of\ Residential\ Accounts} \times \mathit{Average\ Use\ Per\ Account}\end{aligned}$$

This equation is used to develop model projections of sales for each of our four service regions. The sum of the four regional model projections makes up the total residential sales model projection.

The number of residential accounts comes from our residential accounts forecast, which is based housing projections that come from the Conference Board of Canada's economic forecast.

Average use per account, comes from our four regional SAE models. The SAE models' inputs include monthly billed sales data on the average use per account and other load drivers that are specific to the residential sector. The SAE models for the December 2020 forecast are calibrated using the past 10 years of historical drivers, ending in fiscal 2020. To fully utilize our available data, the SAE models included historical sales up to July 2020. For the December 2020 Load Forecast, the SAE model average use per account was adjusted to account for impacts of COVID-19, as described in section 3.2.2.3 below.

The residential sales model projection is then adjusted for load additions and adjustments for rate impacts, DSM savings, and VVO savings, as described in Section 2.1.2, to calculate the residential load forecast.

3.2.1 Residential Accounts Forecast Methodology

BC Hydro's residential accounts forecast is derived from projections of net housing stock growth provided by the Conference Board of Canada (CBoC). Typically, the CBoC provides a housing stock projection for 15 sub-areas within BC for two basic housing types: (1) single family dwellings and (2) multiple housing types (row, apartments, and mobiles). BC Hydro then applies a ratio to the housing stock projections, which reflects the relationship between housing stock to residential accounts and adds the adjusted projection to the existing number of accounts[3]. The 15 sub-area residential accounts forecasts are then aggregated to the four major service regions.

The equation used to develop the residential accounts forecast is as follows:

[8] The term "ratio" mentioned above is a historical average ratio of account growth to growth in net housing stock for two housing types housing for each of the 15 sub-regions. In December 2020 we used the same average ratio of 0.9 used in the October 2018 residential accounts forecast.

$$Number\ of\ accounts\ =\ previous\ year\ forecast\ of\ accounts\ +\ ratio\ \times\ net\ housing\ stock\ projection$$

Due to timing issues associated with developing up-to-date assessments of the COVID-19 pandemic's economic impacts, the CBoC was only able to provide BC Hydro with an economic forecast for the Metro Vancouver area, rather than at the BC Hydro 15 sub-area level. Normally, the CBoC calibrates its BC Hydro 15 sub-regional economic forecast model to its provincial model. When the CBoC released its provincial economic forecast in April 2020, it determined that the economic impact and recovery assumptions with in that forecast were too optimistic (i.e., faster economic recovery) relative to the what was actually occurring and expected to continue to occur within BC. The CBoC similarly concluded that a subsequent economic forecast using its BC Hydro model, informed by its April 2020 provincial forecast, would also be too optimistic. The CBoC also determined it was not able to update its provincial model in time to meet BC Hydro's December 2020 Load Forecast development schedule. To meet BC Hydro's load forecast schedule, the CBoC determined it could use its Metro Vancouver area economic model to provide a limited suite of the economic drivers used in BC Hydro's load forecast models. This economic forecast is contained in the CBoC's "B.C. Economic Outlook 2020" report (CBoC 2020 Report)

Using the more current Metro Vancouver area economic forecast, BC Hydro developed various methods for extrapolating the forecast results to each of BC Hydro's four service regions. The necessary trade-off in favour of using more current economic impact analysis over geographic specificity introduces additional uncertainty to the BC Hydro load forecast. However, this uncertainty is mitigated by the fact that the Metro Vancouver area represents the largest portion of BC Hydro's overall load and there is a considerable geographic overlap between the Metro Vancouver area and the Lower Mainland service region. The extrapolation method used to develop the residential accounts forecast is described below. Similar extrapolation methods were also applied to other economic drivers and customer sectors. Those methods are described further in this document, where applicable.

Since our accounts forecast requires a regional housing stock forecast as an input, we used the following methodology to develop a regional housing stock forecast using the information we had available:

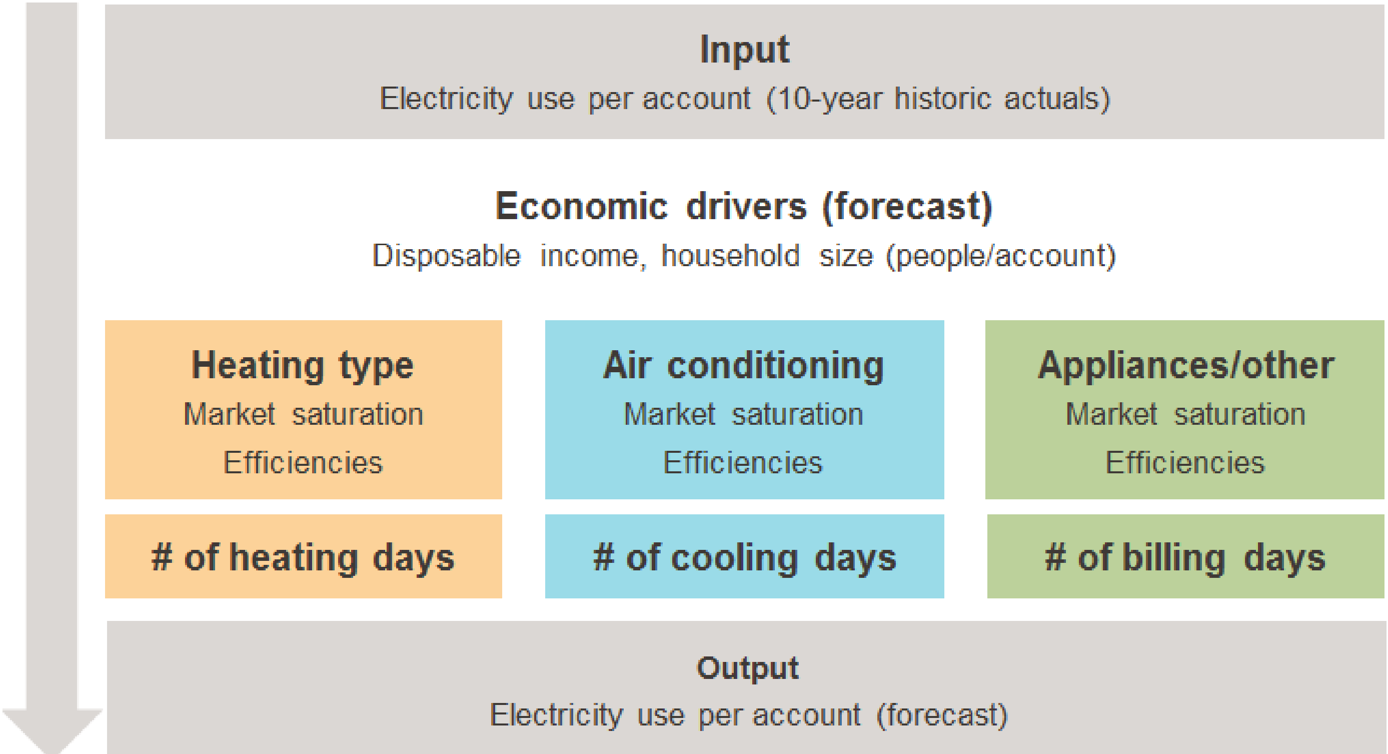
1. The historical housing stock came from CBoC's 2019 Report.
2. The Lower Mainland housing stock forecast was developed by applying the Metro Vancouver annual housing stock annual growth rate from the CBoC's 2020 Report to the last year of history (i.e., fiscal 2019).
3. An adjustment factor was calculated by comparing the newly developed Lower Mainland housing stock forecast to the July 2019 Lower Mainland housing stock forecast.
4. The adjustment factor was applied to the remaining three regional housing stock forecasts (i.e., Vancouver Island, South Interior, North Region) from the CBoC's 2019 Report.

3.2.2 Residential Average Use Per Account Methodology

BC Hydro uses an industry standard SAE model to estimate the average residential use per account for each of our four main service regions. The SAE approach is used by approximately 60 different utilities and organizations throughout North America. This method has been reviewed in several previous regulatory applications including the Fiscal 2021 – Fiscal 2021 Revenue Requirements Application.

Figure 3-2 below is a graphical representation of the SAE model inputs and outputs.

Figure 3-2 Residential SAE Model Inputs and Outputs



Our residential SAE models are an end-use regression model which establishes a historical relationship between the average use per account and the historical values for the following variables:

- economic variables including real personal disposable income and household size represented by people per account,
- non-economic variables including the average efficiency of residential end use of electricity, appliance shares (i.e., percentages of customers that have a specific residential electrical appliance), and
- temperature variables represented by heating and cooling degree days.

The forecasts for these variables and the estimated coefficients of our four regional residential SAE regression models determine the model projections of the average use per account over the forecast period for each region.

The SAE model approach has the following main characteristics:

- A regression element that develops a historical relationship between heating, cooling, and other major end uses of electricity and the average use per account developed from billing data on residential electricity sales and accounts.
- An end-use efficiency element which reflects: (i) future average efficiency projections of residential end uses of electricity for the Pacific region, as developed in 2020 from the U.S. EIA; and (ii) regional BC Hydro data on appliance shares for various end-uses of electricity such as lighting and refrigeration. Regional data on saturation rates come from our historical residential customer end use survey (REUS) while forecasts come from the EIA.
- A temperature element which is measured in heating and cooling degree days. The model is estimated with actual heating and cooling degree days and the forecast is based on a normal temperature which is defined as a ten-year rolling average of monthly heating and cooling degree days that are region specific. Using a ten-year rolling average will better reflect current trends relative to longer term averaging periods.

- An economic element that reflects future projections of economic variables such as real disposable income and household size represented by people per account. The model also contains elasticities which are estimates of the percentage increase in use per account for a one percentage increase in economic variables. The economic forecasts and elasticities are region specific for each model. As described above the CBoC could only develop economic projections for the Metro Vancouver area. BC Hydro's method for extrapolation to develop real disposable income and household size to each of our four service regions is described below. As a result, BC Hydro used the available data from the CBoC and derived its own economic forecasts using the methodology described below.

As described in section 3.2.1., the Metro Vancouver economic forecast is provided in the CBoC's "B.C. Economic Outlook 2020"(CBoC 2020 Report) was developed only for the Metro Vancouver area. BC Hydro used the 2020 forecast and the CBoC's prior July 2019 regional economic forecasts to develop its four regional disposable income and population forecasts. The methodology used is as follows.

3.2.2.1 Regional Population Forecast

The following method for developing updated population forecasts for each BC Hydro's four service regions from CBoC's Metro Vancouver area forecast is similar to that used to develop the regional residential accounts forecasts described in section 3.2.1.

1. Use the historical regional population from CBoC 2019 Report.
2. Develop the Lower Mainland population forecast by applying the Metro Vancouver annual population growth rate forecast from the CBoC 2020 Report to the last year of history (i.e., fiscal 2019).
3. Calculate an adjustment factor by comparing the newly developed Lower Mainland population forecast to the July 2019 population forecast.
4. Apply the adjustment factor to the remaining three regional population forecasts from the CBoC 2019 Report.

In the residential SAE models, the population and accounts forecasts are used to calculate the people per account for the forecast period.

3.2.2.2 Regional Disposable Income Forecast

While the CBoC 2020 Report includes the most relevant economic drivers used to develop our load forecast (i.e., housing stock, population, GDP, and employment), it does not include a regional disposable income forecast. Disposable income is not a significant driver in the residential SAE models (i.e., its elasticity coefficient is low). Nevertheless, for model input completeness, we developed a method to estimate disposable income by performing a regression analyses between disposable income and GDP, population and employment, respectively, to determine which of those other economic drivers was the most statistically significant predictor of disposable income.

Based on our analysis, we found total GDP to be the best predictor.

To develop regional GDP forecasts from the CBoC's Metro Vancouver GDP forecast, we applied the same extrapolation process used to develop regional housing stock and population forecasts. We then used a linear regression shown below to determine the required statistical parameters for developing a regional disposable income from GDP.

$$Regional\ Disposable\ Income = m \times Regional\ Total\ GDP + b$$

Where m is the slope and b is the y-intercept.

BC Hydro used the available 18 years of regional history of total GDP and disposable income from the CBoC 2019 Report and used the above equation to determine its coefficients (i.e., slope and y-intercept).

We then used those statistical coefficients as well as the regional total GDP forecast to develop a regional disposable income forecast.

3.2.2.3 COVID-19 Adjustments to Residential Use per Account Forecast

The December 2020 Load Forecast incorporates the COVID-19 pandemic's estimated impacts on residential use per account that would not otherwise be captured in our SAE models, recognizing there is uncertainty in quantifying those impacts. Two main factors we considered include:

1. People working from home due to public health measures, and
2. Changes in daily usage patterns as more people are working from home and spending more time at home.

To capture the impact of COVID-19 on the residential use per account, BC Hydro compared five months of actual residential consumption data in fiscal 2021 (April 2021 to August 2021) on an electric heating and non-electric heating basis to the previous year to observe the pattern changes associated with COVID-19. The following methodology was used to adjust the regional residential SAE use per account forecasts:

- For non-electrically heated homes, we assumed the observed five-month average increase in use per account would continue for the rest of fiscal 2021.
- For electrically heated homes, we assumed the observed five-month average increase in use per account would continue until November 2020 and will increase to an assumed 10 per cent for the remainder of the fiscal year. This assumption was based on our professional judgement.
- We calculated weights for each of the two heating types based on their associated share of accounts and a total adjustment factor was calculated.
- We used this adjustment factor to adjust the regional SAE model projections for fiscal 2021.
- For fiscal 2023 (and beyond), we assumed 10 per cent of people will continue to work from home even as the provincial economy returns to normal following the lifting of COVID-19 public health measure. For comparison, 50 per cent of people were estimated to be working from home as of August 2020. Our assumption that 10 per cent more people will continue to work from home as the post-COVID normal is based on professional judgment in consultation with the CBoC. This assumption was carried forward throughout the forecast period as we assumed there will be a permanent structural change due to COVID-19.
- For fiscal 2022, we took the monthly average of use per account between fiscal 2021 and fiscal 2023.

3.3 RESIDENTIAL FORECAST RESULTS

3.3.1 Residential Accounts Forecast

Table 3-1 outlines the December 2020 Load Forecast's expectations for residential customer accounts out to fiscal 2041.

Table 3-1 Residential Accounts History and Reference Forecast

Fiscal Year	Residential Accounts Forecast (Number of Accounts)
Actual	
F2015	1,727,945
F2016	1,751,296
F2017	1,776,503
F2018	1,803,752
F2019	1,833,106
F2020	1,863,569
Forecast	
F2021	1,882,761
F2022	1,917,132
F2023	1,945,968
F2024	1,972,370
F2025	1,999,173
F2026	2,021,681
F2027	2,044,245
F2028	2,066,835
F2029	2,089,396
F2030	2,111,897
F2031	2,132,766
F2032	2,153,073
F2033	2,172,860
F2034	2,192,177
F2035	2,211,047
F2036	2,229,491
F2037	2,247,543
F2038	2,265,216
F2039	2,282,491
F2040	2,299,356
F2041	2,315,842
Compound Annual Growth Rates	
5-year History CAGR (F15 - F20)	1.5%
5-year CAGR (F20 - F25)	1.4%
10-year CAGR (F20 - F30)	1.3%
20-year CAGR (F20 - F40)	1.1%

The account forecast shows an average annual growth of about 27,121 (1.4%) accounts over each of the next five years ending fiscal 2025. This is slightly lower than the historical five-year average growth rate which was about 27,125 (1.5%) accounts per year.

3.3.2 Residential Forecast Build-up

Table 3-2 below shows the details of the residential forecast build up for select years as examples to show how the Residential Reference Load Forecast is derived. This forecast is an aggregation of model projections including the COVID-19 adjustments described in section 3.2.3, load additions for codes and standards overlap, EVs, LCE/fuel switching and adjustments for rate impacts, DSM savings, and VVO savings.

Table 3-2 – Residential Reference Load Forecast Build-up

Fiscal Year	Accounts (# Accounts)	COVID-19 Adjusted SAE Use per Account (kWh/ Account)	Model Projection[1] (GWh)	Codes Overlap Adjustments (GWh)	EV Load Additions (GWh)	LCE/Fuel Switching Additions (GWh)	Rate Impacts[2] (GWh)	DSM (GWh)	VVO (GWh)	Residential Load Forecast (GWh)
F2021	1,882,761	10,477	19,723	37	135	17	48	(152)	(10)	19,799
F2022	1,917,132	10,304	19,753	77	229	36	61	(355)	(12)	19,789
F2023	1,945,968	10,132	19,714	108	309	36	37	(511)	(14)	19,678
F2024	1,972,370	10,112	19,943	136	400	36	52	(659)	(16)	19,892
F2025	1,999,173	10,065	20,119	164	504	36	28	(800)	(18)	20,033
F2026	2,021,681	10,037	20,289	189	624	36	62	(930)	(19)	20,250
F2031	2,132,766	10,016	21,360	288	1,534	36	68	(1,441)	(33)	21,812
F2036	2,229,491	10,108	22,534	368	2,841	19	75	(1,845)	(44)	23,948
F2041	2,315,842	10,263	23,765	448	4,270	0	83	(2,150)	(57)	26,360

Table notes:

1. A model projection is average use per account times the number of residential accounts which equals model sales. The model projection above is the sum model projections from all four regions, including the adjustments made for COVID-19.
2. Rate Impacts is an estimation of load reduction based on formula that include our forecast of real electricity rate increases, a price elasticity assumption of -0.1 and the residential model projections, load adjustments, and load additions.

3.3.3 Residential Reference Load Forecast

Table 3-3 provides the Residential sector sales history and Reference Load Forecast after adjustments.

Table 3-3 – Residential Sales History and Reference Load Forecast After Adjustments

Fiscal Year	Residential Reference Forecast (GWh)
Actual (Temperature Normalized)	
F2015	17,973
F2016	18,019
F2017	17,952
F2018	17,997
F2019	17,876
F2020	18,349
Forecast	
F2021	19,799
F2022	19,789
F2023	19,678
F2024	19,892
F2025	20,033
F2026	20,250
F2027	20,494
F2028	20,809
F2029	21,112
F2030	21,458
F2031	21,812
F2032	22,215
F2033	22,593
F2034	23,019
F2035	23,460
F2036	23,948
F2037	24,379
F2038	24,852
F2039	25,328
F2040	25,833
F2041	26,360
Compound Annual Growth Rates	
5-year History CAGR (F15 - F20)	0.4%
5-year CAGR (F20 - F25)	1.8%
10-year CAGR (F20 - F30)	1.6%
20-year CAGR (F20 - F40)	1.7%

3.4 RESIDENTIAL USE PER ACCOUNT FORECAST AFTER ADJUSTMENTS

Table 3-4 provides the historical and forecast residential average use per account. The forecast use per account includes all post-model adjustments and is therefore a more appropriate comparison the historical use per account than the unadjusted SAE model projections.

Table 3-4 - Residential Reference Use per Account Forecast Results After Adjustments

Fiscal Year	Residential Use per Account Including All Adjustments (kWh/Account)
Actual (Temperature Normalized)	
F2015	10,587
F2016	10,387
F2017	10,177
F2018	10,053
F2019	9,830
F2020	9,927
Forecast	
F2021	10,516
F2022	10,322
F2023	10,112
F2024	10,085
F2025	10,021
F2026	10,016
F2027	10,025
F2028	10,068
F2029	10,104
F2030	10,160
F2031	10,227
F2032	10,318
F2033	10,398
F2034	10,500
F2035	10,610
F2036	10,742
F2037	10,847
F2038	10,971
F2039	11,097
F2040	11,235
F2041	11,382
Compound Annual Growth Rates	
5-year History CAGR (F15 - F20)	(1.6%)
5-year CAGR (F20 - F25)	0.6%
10-year CAGR (F20 - F30)	0.4%
20-year CAGR (F20 - F40)	0.7%

The results indicate that average residential use per account is expected to increase relative to historic trends primarily due the change in consumption patterns due to COVID-19, which more than offsets a declining use per account trend primarily driven by increased end-use efficiency improvements. Over the forecast period, residential use per account is also expected to increase relative to historical trends due to the following factors:

- The assumption that COVID-19 will have a permanent structural change on the commercial sector causing more people (i.e., 10 per cent) to continue to work from home;
- The expected growth in light duty electric vehicles; and
- Other factors such as fuel switching and economic drivers (i.e., disposable income and people-per-account) will have tend to increase use per account although these are currently not as significant as COVID-19 structural change assumptions associated with COVID-19 and EVs.

3.5 RESIDENTIAL FORECAST UNCERTAINTIES

The Residential Reference Load Forecast reflects the combination of several forecasts such as account growth, use per account projections, adjustments for code and standards, load additions, and load reductions. There are uncertainties associated with the key economic variables (i.e., housing stock, population) and non-economic variables (temperature, end-use efficiency, COVID-19, EVs, LCE/fuel switching). Each of these uncertainties create both upside and downside risks for the residential load forecast. Certainly, COVID-19 has introduced a substantive additional layer of uncertainty to the load forecast.

As such there is uncertainty in all of these components that make up the residential forecast. While some of these uncertainties may offset each other, there could be conditions that could lead to a variance in the forecast where the actuals are higher or lower than forecast.

There are also uncertainties associated with the modelling itself, such as the accuracy of using statistically determined relationships between drivers and load to forecast loads at a point in time where the nature of those relationships may be changing. Our unadjusted residential use per account forecasts come from our SAE models, which reduces the risk that our residential forecasting models are not capturing a proper relationship between residential electricity consumption and economic drivers. However, as discussed in earlier sections, the need to modify our method to develop economic drivers for BC Hydro's four service regions based on the CBoC's Metro Vancouver economic forecast adds additional modelling uncertainty. However, we believe this uncertainty is small relative to other uncertainties given the overall robustness of our residential SAE models and that a large portion of BC Hydro's residential load is in the Metro Vancouver area.

While some uncertainties may offset each other, there could be conditions that could lead to a variance in the forecast where the actuals are higher or lower than forecast. Some of the major uncertainties that result in upside and downside risks are list below.

3.5.1 Number of Accounts

Housing trends may differ from the CBoC forecast. Factors that could impact housing trends in B.C. over the next several years include:

- provincial housing policy on affordable supply via targeted smaller unit construction,
- federal commitments to affordable housing, and
- government policy aimed at reducing demand and rising house prices through taxes and tightening of mortgage rules.

There is uncertainty as to how consumers will react to all of these measures which are occurring simultaneously.

3.5.2 Use Per Account

The unadjusted use per account forecast is based on our SAE model projections which reflect economic factors (real disposable income, household size) and changes in average efficiency and market penetration (i.e., saturation) of residential appliances. All of these factors have the potential to contribute to uncertainty in our load projections. In addition, government policies that increase or lower incentives for load adjustments, such as EVs and fuel switching under CleanBC's Better Buildings/Home program contribute to use per account variances.

Examples of other factors that influence use per account in an upward direction include:

- increases in home sizes (e.g., larger single-family dwellings),
- increases in air conditioning and other cooling devices, and
- increases in electronic devices.

Examples of other factors that decrease use per account are:

- increases in smaller home sizes (i.e., faster movement towards denser multiple housing units),

- increased use of programmable devices (e.g., thermostats), and
- customers becoming more conscious of electricity use.

3.5.3 Temperature

In the short term, temperature can be highly variable relative to our assumptions of a rolling 10-year average trend. Therefore, in any one year, there is a risk that temperature and associated weather may have an impact on residential sales. For example, after the El Nino event of fiscal 2015, sales to the residential sector declined by close to five per cent between fiscal 2014 and fiscal 2015 mainly due to warmer temperatures. Like most utilities, we develop a forecast based on historical temperature average or on a temperature normalized basis. This is standard practice across most utilities rather than developing an electricity sales forecast based on a prediction of future temperatures and weather conditions.

3.5.4 COVID-19

The COVID-19 pandemic adds uncertainty to the residential load forecast. The upside and downside risks relative to the reference forecast include the following:

- Timing of when public health measures are lifted is sooner/later than forecast.
- Pace and magnitude of the post-COVID economic recovery affecting residential load drivers (housing stock, population, disposable income) is better/worse than forecast
- People working from home due to public health policies and as permanent structural changes are higher/lower than assume, and
- Change in daily usage (use per account) patterns associated with more people are working from home and spending more time at home results in higher/lower electricity consumption than assumed .

The high and low forecasts are developed to capture some of this uncertainty. Further information on the residential high and low forecasts is provided in section 8.4.1.

4.0 Commercial Forecast

4.1 COMMERCIAL SECTOR DESCRIPTION

At the end of fiscal 2020, there were 185,488 commercial accounts and commercial billed sales totalled 14,338 GWh. The commercial sector as of fiscal 2020 was about 28 per cent of BC Hydro's total firm sales.

Within the commercial sector we group customers based on the type of service they receive:

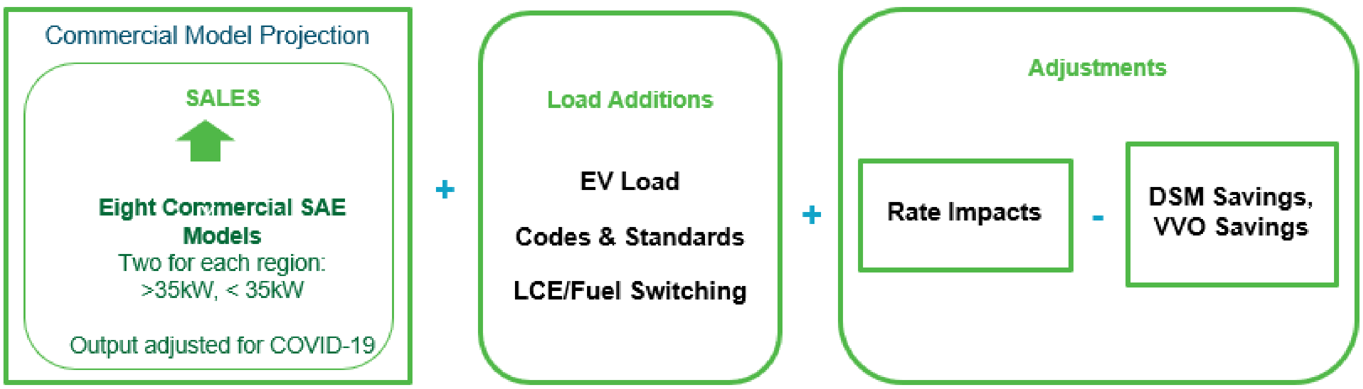
- customers with a demand under 35 kW peak demand within a month , which includes operations such as small offices, small retail stores, restaurants, and motels, and
- customers with a demand greater than 35 kW peak demand within a month which includes buildings such as large offices, larger retail stores, hospitals and hotels.

Given the diversity of businesses and type of operations within the commercial sector, commercial electricity sales are not as sensitive to temperature as the residential sector. However, some commercial customers such as schools, restaurants, and smaller health care facilities are more sensitive to temperature Therefore we still factor historical average temperature variables (i.e., heating and cooling degree days) into our commercial forecasting models. As such, the commercial forecasts are prepared on a temperature normalized basis and the actual commercial sales are temperature normalized. For details on the temperature normalization process see Appendix C of this report.

4.2 COMMERCIAL FORECAST METHODOLOGY

Similar to the residential sector, the commercial sector load forecast development begins with model projections. Our commercial model projections come from eight SAE models. These eight models correspond to our four major service regions (Lower Mainland, Vancouver Island, South Interior, and North Region) each then divided into the two levels of electrical service mentioned earlier (< 35 kW or > 35 kW). Most commercial sales are in the Lower Mainland over 35 kW customer group and Vancouver Island over 35 kW customer group. Combined, these two customer groups make up over half of the total commercial sales. Figure 4-1 shows the commercial forecasting process and build-up.

Figure 4-1 Commercial Reference Load Forecast Build-up



Looking to the left-hand portion of Figure 4-1, the starting point in the commercial forecasting process is the commercial SAE model projections.

The general structure of our commercial SAE models is the same as the SAE model diagram shown in the Residential Section (Figure 3-1 of section 3.2) with two exceptions: the inputs are different, and model projections for the commercial sector are different, as they are on a billed sales basis versus an average use per account basis.

Each of our eight commercial SAE models is an end use regression model which determines a relationship between historical commercial billed sales and historical values of these two types of variables:

- **economic variables** including employment, retail sales and commercial GDP; and
- **non-economic variables** including the average efficiency of commercial end uses of electricity and shares of commercial end uses (i.e., the percentages of commercial customers which have a specific commercial end use). The history and forecast of bo th these variables come from the 2020 dataset developed by the U.S. EIA for the Pacific region. Other non-economic variables include temperature variables represented by heating and cooling degree days.

The forecasts for these variables and the estimated regression coefficients of the eight commercial SAE regression models determine the commercial model projections of electricity sales over the forecast period. Similar to the residential SAE model, our commercial SAE models are calibrated to the past 10 years of history, ending in fiscal 2020.

Within our SAE commercial models, one factor determining the projected growth in electricity sales is the anticipated level of future economic activity and its impact. The relationship between the commercial sales and these economic variables are represented as economic elasticities (distinct from price elasticities) in the SAE model.

For December 2020 the SAE model sales forecast was adjusted for impacts of COVID-19 as described in section 4.2.2 below.

Once the billed sales forecast is complete, the same adjustments are made to the commercial forecast as the residential forecast. These adjustments are described in section 4.2.2 below.

4.2.1 Conference Board of Canada – Economic Drivers

As described in section 3.2.1, the CBoC's 2020 economic forecast was developed only for the Metro Vancouver area. BC Hydro used this forecast and CBoC's prior July 2019 regional economic forecasts to develop its four regional commercial GDP and retail sales forecasts. We used the same methodology outlined in section 3.2.2.1 (population) to derive the regional employment forecasts. Since the CBoC was not able to provide a commercial GDP forecast for Metro Vancouver, and we used a similar linear regression methodology to that methodology outlined in section 3.2.2.2 (disposable income) to derive the regional commercial GDP forecasts from the CBoC's GDP forecasts.

4.2.2 COVID-19 Adjustments to Commercial SAE Model Projections

Similar to the residential sector, the commercial sector forecast incorporates the COVID-19 pandemic's estimated impacts that would not otherwise be picked up in our commercial SAE models. Estimating the pandemic's impacts on commercial sector sales entails a greater degree of uncertainty relative to estimating its impact on residential use per account. This increased uncertainty arises because the pandemic's impact was not uniformly distributed among all commercial classes. For example, accommodation and food service (restaurants) business have been more impacted relative to food retail (i.e., grocery stores) businesses.

To capture the short term and long-term impacts of COVID-19 on such a diverse sector, we used analyzed actual consumption patterns for 15 specific business classes (NAICs codes).[4]

To capture the impact of COVID-19 on the commercial sector, we compared the available five months of actuals in fiscal 2021 (April 2021 to August 2021) to the previous year to observe the patterns associated with COVID-19. The following methodology was used to adjust the regional commercial SAE sales forecasts:

- For fiscal 2021, we used the same 15 business classes (by NAICs code) identified by the CBoC to perform the comparison between the first five months of actuals in fiscal 2021 and the previous year.
    - For each business class we used our professional judgement and the observed consumption trends up to August 2020 to assume a per cent decline at the end of F2021 (i.e., March 2021).
    - We then linearly interpolated from July 2020 (actual) to March 2021 (assumed) to come up with a trend.
- For fiscal 2022, BC Hydro took the monthly average between fiscal 2021 and fiscal 2023.
- For fiscal 2023 (and beyond), we used our historical data to calculate the proportion of office buildings load making up the total commercial sector load of office load. We then assumed 10 per cent of that office load to reflect a permanent structural change due to the pandemic. This assumed is based on professional judgment in consultation with the CBoC.

4.3 COMMERCIAL FORECAST RESULTS

4.3.1 Commercial Forecast Build-up

Table 4-1 below shows the details of the commercial forecast build-up for select years as examples to show how the Commercial Reference Load Forecast is derived. This forecast is an aggregation of model projections including the COVID-19 adjustments described in section 4.2.2, load additions for codes and standards overlap, EVs, LCE/fuel switching and adjustments for rate impacts, DSM savings, and VVO savings.

[4] NAICS - North American Industry Classification System

Table 4-1 – Commercial Reference Load Forecast Build-up

Fiscal Year	COVID-19 Adjusted SAE Model Projection[1] (GWh)	Codes Overlap Adjustment (GWh)	EV Load Addition (GWh)	LCE/Fuel Switching Load Addition (GWh)	Rate Impact[2] (GWh)	DSM (GWh)	VVO (GWh)	Commercial Load Forecast (GWh)
F2021	12,863	31	24	19	31	(97)	(8)	12,864
F2022	13,715	70	40	48	42	(252)	(10)	13,654
F2023	14,131	105	54	48	26	(386)	(11)	13,968
F2024	14,152	139	71	48	36	(513)	(13)	13,921
F2025	14,140	171	89	48	20	(633)	(14)	13,820
F2026	14,132	202	110	48	42	(744)	(15)	13,774
F2031	14,088	322	271	46	43	(1,145)	(26)	13,598
F2036	14,038	400	501	46	44	(1,451)	(35)	13,543
F2041	14,011	480	754	12	45	(1,650)	(46)	13,605

Table Notes

1. The model projection is the sum total of all commercial SAE model projections, including the adjustments made for COVID-19.
2. Rate Impacts is an estimation of load reduction based on formula that include our forecast of real electricity rate increases, a price elasticity assumption of -0.1 and the residential model projections, load adjustments, and load additions.

4.3.2 Commercial Reference Load Forecast

Table 4-2 provides the Commercial sector sales history and Reference Load Forecast, after adjustments.

Table 4-2 – Commercial Sales History and Reference Load Forecast After Adjustments

Fiscal Year	Commercial Reference Forecast (GWh)
Actual (Temperature Normalized)	
F2015	14,539
F2016	14,345
F2017	14,576
F2018	14,494
F2019	14,557
F2020	14,336
Forecast	
F2021	12,864
F2022	13,654
F2023	13,968
F2024	13,921
F2025	13,820
F2026	13,774
F2027	13,723
F2028	13,698
F2029	13,655
F2030	13,627
F2031	13,598
F2032	13,580
F2033	13,556
F2034	13,544
F2035	13,537
F2036	13,543
F2037	13,536
F2038	13,543
F2039	13,543
F2040	13,558
F2041	13,605
Compound Annual Growth Rates	
5-year History CAGR (F15 - F20)	(0.3%)
5-year CAGR (F20 - F25)	(0.7%)
10-year CAGR (F20 - F30)	(0.5%)
20-year CAGR (F20 - F40)	(0.3%)

4.4 COMMERCIAL FORECAST UNCERTAINTIES

Similar to the residential sector, COVID-19 has increased the complexity in developing a long-term commercial load forecast. For the commercial sector, this uncertainty is even greater due to the sector's broad diversity.

The commercial load forecast reflects the combination of several forecasts such as model projections, adjustments for codes and standards, load additions, and load reductions. There are uncertainties associated with the key economic variables (i.e., commercial GDP, employment, retail sales) and non-economic variables (temperature, end-use efficiency, COVID-19, EVs, LCE/fuel switching). Each of these uncertainties creates both upside and downside risks for the commercial load forecast. Even more than the residential sector, COVID-19 has introduced a substantive additional layer of uncertainty to the commercial sector forecast.

There are also uncertainties associated with the modelling itself, such as the accuracy of using statistically determined relationship between drivers and load to forecast loads at a point in time where the nature of those relationships may be changing. Our unadjusted commercial sales forecasts come from our SAE models which reduces the risk that our commercial forecasting models are not capturing a proper relationship between historical sales and drivers of commercial loads. In addition, our commercial forecasting models have multiple drivers of load as opposed to a single load driver. This reduces forecast risk in that our model projections are from multiple external forecasts rather than one external forecast of one economic variable. However, as discussed earlier sections, the need to modify our method to develop economic drivers for BC Hydro's four service regions based on the CBoC's Metro Vancouver economic forecast adds additional modelling uncertainty. However, we believe this uncertainty is small relative to other uncertainties given the overall robustness of our commercial SAE models and that a large portion of BC Hydro's commercial load is in the Metro Vancouver area.

While some uncertainties may offset each other, there could be conditions that could lead to a variance in the forecast where the actuals are higher or lower than forecast.

Examples of other factors that could result in lower than forecast commercial sales include:

- a high Canadian dollar lowers tourism and retail sales, and
- growth in online shopping and internet business that could result in less activity and future expansion in commercial stores and therefore reduce demand for electricity sales to the commercial retail sector.

Examples of other factors that could lead to higher than forecast commercial sales include:

- a lower Canadian dollar which encourages tourism and retail sales, and
- expansion of the technology sector in B.C.

The COVID-19 pandemic adds additional uncertainty to the commercial load forecast. The upside and downside risks relative to the reference forecast include the following:

- Timing of when public health measures are lifted relative to what is forecast.
- Pace and magnitude of the post-COVID economic recovery affecting commercial load drivers (commercial GDP, employment, retail sales) that may be better/worse than forecast

5.0 Light Industrial Forecast

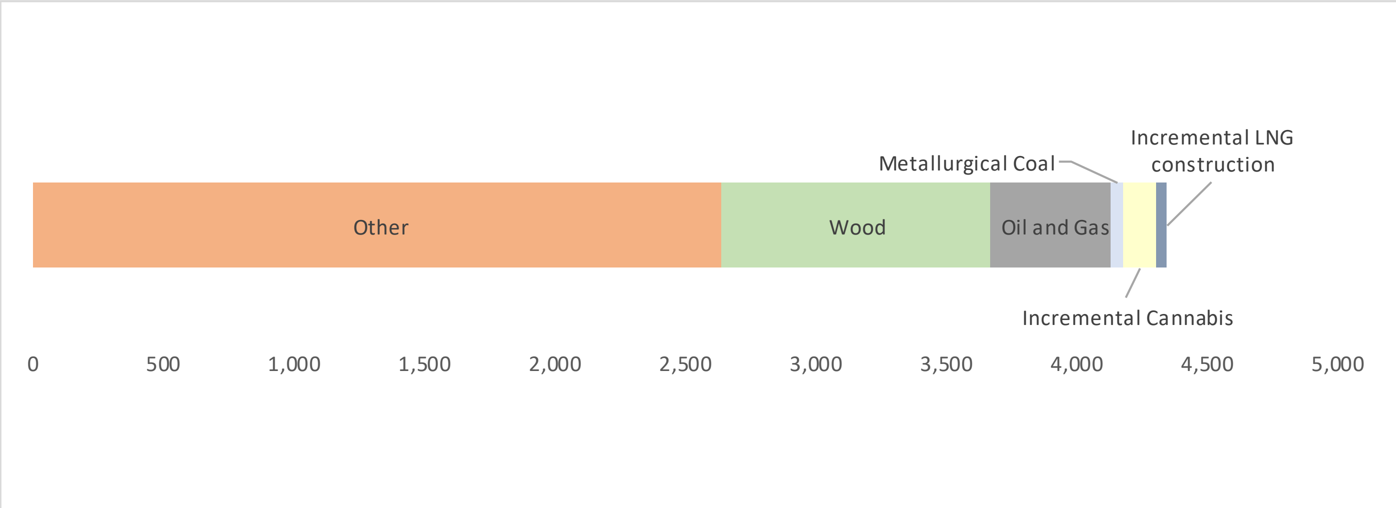
5.1 LIGHT INDUSTRIAL SECTOR DESCRIPTION

The light industrial sector consists of approximately 30,000 customers connected at the distribution level. At the end of fiscal 2020, sales to the light industrial sector were 4,311 GWh or nine per cent of our total firm sales. The light industrial sector is subdivided into the following sub-sectors:

- other industrial loads which include various activities such as agriculture, construction, and manufacturing (other),
- forestry
- oil and gas,
- metallurgical coal mining,
- incremental cannabis, and
- incremental LNG construction loads.

Figure 5-1 below shows the relative contribution of each of the above sub-sectors, based on the fiscal 2021 forecast.

Figure 5-1 – Light Industrial Sub-Sectors Fiscal 2021 (GWh)



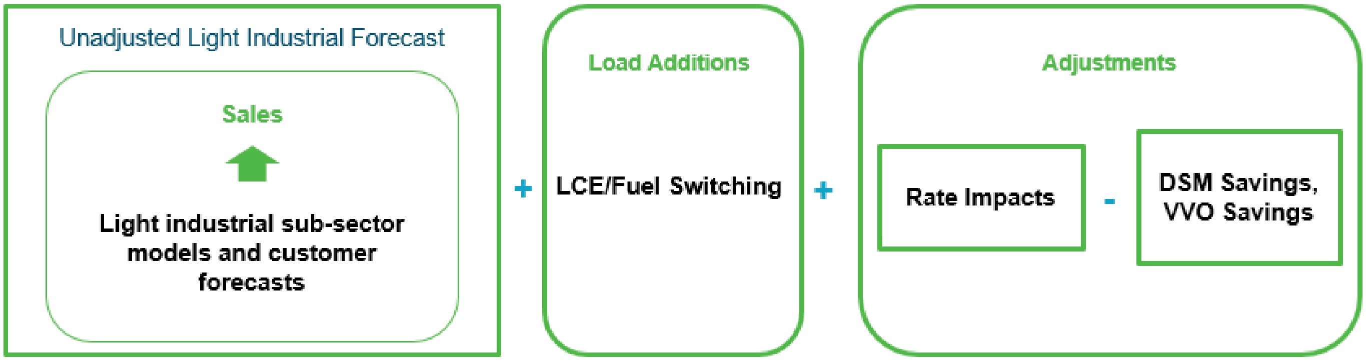
The light industrial sector is not sensitive to temperature variation and is therefore not prepared on a temperature normalized basis.

5.2 LIGHT INDUSTRIAL FORECAST METHODOLOGY

The Light Industrial Reference Load Forecast is an aggregation of model projections and customer forecasts from the sub-sectors listed above. As described in Section 2.1.2, adjustments to these base model projections are made to build up the complete light industrial load forecast.

Figure 5-2 shows the light industrial forecasting process and build-up.

Figure 5-2 Light Industrial Reference Load Forecast Build-up



Each of the sub-sectors uses a different forecast methodology. These methodologies are described below. Since the light industrial sector is not developed on an end-use basis there is no need for adjustments due to overlaps in codes and standards. In addition, there is no allocation of EV load to this sector.

5.2.1 Other Light Industrial Loads

Other light industrial load projections are based on a regression model of sales to real provincial GDP.

Equation 5-1 is the model used to develop the projections for the other light industrial loads. The parameters of this model are informed by coefficients from a regression model of the log of sales per unit of provincial GDP and a time trend.

The model used to project the other light industrial loads is the following expression:

Equation 5-1

$$INDD = \left(e^{\propto + \beta T}\right) \times GDP$$

Where:

INDD is other light industrial billed sales (excluding sales for the forestry, oil and gas, coal sub-sectors, cannabis, and LNG construction),

α and β are the regression coefficients from a log regression model of the log of sales per unit of provincial GDP, and a time trend,

e is exponential base,

T is a time trend variable, and

GDP represents the provincial real GDP forecast.

The statistical characteristic and results of the regression mode are provided in Table 5-1. These results provide the coefficients for our forecasting model. The regression model is a good fit to the historical data, and therefore viewed as a sound model to develop the forecast.

Table 5-1 – Regression Results

Variable and Statistics	Result
Constant	2.387 (p-value of 0.0%)
Independent Trend Variable	-0.004 (p-value of 0.0%)
Adjusted R-Square	0.3
Auto-correlation Range (AR)	1-1.34
Durbin-Watson Statistic	1.1
Auto-correlation test result	Indeterminate

The GDP forecast used for the December 2020 light industrial regression for the other sub-sector is shown in Table 5-2 below.

Table 5-2 - GDP forecast Used for Light Industrial Other Sub-sector

Fiscal Year	GDP Growth
F2021	(6.7%)
F2022	3.0%
F2023	3.8%
F2024	2.7%
F2025	1.8%
F2026	2.2%
F2027	2.2%
F2028	2.3%
F2029	1.9%
F2030	1.5%
F2031	1.9%
F2032	1.9%
F2033	1.9%
F2034	1.8%
F2035	1.7%
F2036	1.8%
F2037	1.7%
F2038	1.7%
F2039	1.8%
F2040	1.8%
F2041	1.9%

Table notes:

1. The source for F2021 and F2022 is the Ministry of Finance First Quarterly report released September 2020.
2. The source for F2023-F2041 is BC Hydro's provincial forecast based on the CBoC's Metro Vancouver forecast.

5.2.2 Forestry

Customers within the forestry sub-sector encompass sawmills, panel mills and pellet plants. Mill by mill production projections are developed for this sub-sector by the same experts who develop production forecasts for the large industrial wood products segment. The individual mill production forecasts are aggregated together on a regional basis and then multiplied by intensity factors (i.e. kWh/unit of production) to develop regional model projections. These projections are then aggregated to make up the total forestry sub-sector forecast.

5.2.3 Oil and Gas

Oil and gas customers are involved in production and processing, transportation (pipelines, pump stations, truck terminals) and support services for the oil and gas industry. This sub-sector's forecast is determined on an account by account basis. Account projections are developed with information from BC Hydro Distribution area planners and Load Interconnections personnel. Probability assessments are carried out on customer requests from natural gas processing plants and natural gas pipeline customers that make up most of the growth in the current forecast.

5.2.4 Metallurgical Coal Mining

There are three metallurgical coal mining customers. This forecast is developed on an account by account basis using a probability weighted approach.

5.2.5 Incremental Cannabis

The incremental forecast is developed on and account by account basis, with consideration of customer requested loads that are deemed highly probable based on their advanced stage of progress in BC Hydro's interconnection process.

5.2.6 Incremental LNG Construction Loads

The additional required load expected to power the construction of LNG plants and other facilities is considered. These construction loads are considered separately from plant operational requirements and are removed from the forecast once construction is complete.

5.3 LIGHT INDUSTRIAL FORECAST RESULTS

5.3.1 Unadjusted Light Industrial Forecast

Over the past five years, electricity sales across all light industrial customers have grown by 0.4 per cent on average (i.e., five-year average compound annual growth rate). This growth has been led by increases in sales in the other light industrial sub-sector.

Table 5-3 shows the forecast for the light industrial sector before LCE/fuel switching additions and adjustments for rate impacts, DSM and VVO savings. The load additions and adjustments are applied to the consolidated light industrial forecast, which is provided in Table 5-5.

Table 5-3 – Light Industrial Sales History and Reference Load Forecast Before Adjustments

Fiscal Year	Other (GWh)	Wood (GWh)	Oil and Gas (GWh)	Metallurgical Coal (GWh)	Incremental Cannabis (GWh)	Incremental LNG construction (GWh)	Total (GWh)
Actual							
F2015	2,486	1,211	479	51			4,227
F2016	2,471	1,199	455	22			4,148
F2017	2,582	1,232	440	21			4,275
F2018	2,685	1,150	481	37	12		4,364
F2019	2,760	1,138	427	53	44		4,422
F2020	2,766	1,014	418	50	64		4,311
Forecast							
F2021	2,633	1,034	458	50	123	42	4,341
F2022	2,699	1,150	527	46	151	102	4,675
F2023	2,787	1,160	575	45	209	102	4,878
F2024	2,848	1,155	615	43	213	12	4,886
F2025	2,887	1,155	634	43	213	7	4,938
F2026	2,936	1,155	616	43	217	7	4,974
F2027	2,985	1,155	616	43	217	7	5,024
F2028	3,040	1,155	616	43	218	7	5,079
F2029	3,084	1,155	616	43	218	7	5,123
F2030	3,115	1,155	616	43	218	7	5,154
F2031	3,158	1,155	616	43	218	7	5,197

Fiscal Year	Other (GWh)	Wood (GWh)	Oil and Gas (GWh)	Metallurgical Coal (GWh)	Incremental Cannabis (GWh)	Incremental LNG construction (GWh)	Total (GWh)
F2032	3,203	1,155	616	43	218	-	5,235
F2033	3,247	1,155	616	43	218	-	5,280
F2034	3,290	1,155	616	43	218	-	5,322
F2035	3,330	1,155	616	43	218	-	5,362
F2036	3,373	1,155	616	43	218	-	5,406
F2037	3,416	1,155	611	43	218	-	5,443
F2038	3,460	1,155	606	43	218	-	5,482
F2039	3,506	1,155	601	43	218	-	5,523
F2040	3,553	1,155	601	43	218	-	5,571
F2041	3,604	1,155	601	43	218	-	5,621
Compound Annual Growth Rates							
5-year History CAGR (F15 - F20)	2.2%	(3.5%)	(2.7%)	(0.4%)			0.4%
5-year CAGR (F20 - F25)	0.9%	2.6%	8.7%	(2.8%)	27.1%		2.8%
10-year CAGR (F20 - F30)	1.2%	1.3%	4.0%	(1.4%)	13.0%		1.8%
20-year CAGR (F20 - F40)	1.3%	0.7%	1.8%	(0.7%)	6.3%		1.3%

Table notes:

1. The actuals for cannabis are estimates based on the spot (incremental) loads for customers included in the October 2018 Load Forecast. Forecast.
2. The actuals for LNG construction are captured under the actuals for other subsector. As such, historical and forecast compound growth rates are not shown.
3. Forecast values do not indluce LCE/Fuel switching adjustments.

The light industrial subsector is expected to experience modest growth in fiscal 2021, as the drop in the other subsector due to COVID-19 pandemic impacts on provincial GDP is offset by incremental additions to cannabis and LNG construction loads, as well as a small increase in the oil and gas subsector.

The other subsector is forecast to recover in fiscal 2022 and returns to pre-pandemic load levels by the end of fiscal 2023. The light industrial sector is forecast to grow approximately 1,300 GWh by fiscal 2041, with growth led by the other subsector (~800 GWh), as well as oil and gas (~200 GWh), incremental cannabis (~200 GWh) and forestry (~100 GWh).

5.3.2 Light Industrial Forecast Build-up

Table 5-4 below shows the details of the light industrial forecast build up for select years as examples, to show the progression from the unadjusted forecast projections above to the Light Industrial Reference Load Forecast. This forecast includes the unadjusted aggregation of the various segments making up the light industrial sector, load additions for LCE/fuel switching additions and adjustments for rate impacts, DSM and VVO savings.

Table 5-4 – Light Industrial Reference Load Forecast Build-up

Fiscal Year	Light Industrial Model Projections / Customer Forecast [1] (GWh)	LCE/Fuel Switching Load Additions (GWh)	Rate Impact[2] (GWh)	DSM (GWh)	VVO Savings (GWh)	Light Industrial Load Forecast[3] (GWh)
F2021	4,341	0	11	(24)	(2)	4,326
F2022	4,675	0	14	(59)	(2)	4,628
F2023	4,878	28	9	(87)	(3)	4,825
F2024	4,886	28	12	(114)	(3)	4,810
F2025	4,938	28	7	(144)	(4)	4,825
F2026	4,974	28	15	(171)	(4)	4,841
F2031	5,197	28	15	(298)	(7)	4,936
F2036	5,406	28	16	(370)	(9)	5,071
F2041	5,621	28	17	(375)	(11)	5,279

Table notes:

1. Includes the other sub-sector model projections and customer forecasts for wood, oil and gas, metallurgical coal, incremental cannabis and incremental construction loads for future LNG terminals.

5.3.3 Light Industrial Reference Load Forecast

Table 5-5 shows the Light Industrial sales history and forecast after adjustments.

Table 5-5 – Light Industrial Sales History and Reference Load Forecast After Adjustments

Fiscal Year	Light Industrial Reference Forecast (GWh)
Actual	
F2015	4,227
F2016	4,148
F2017	4,275
F2018	4,364
F2019	4,422
F2020	4,311
Forecast	
F2021	4,326
F2022	4,628
F2023	4,825
F2024	4,810
F2025	4,825
F2026	4,841
F2027	4,867
F2028	4,896
F2029	4,913
F2030	4,917
F2031	4,935
F2032	4,952
F2033	4,977
F2034	5,006
F2035	5,037
F2036	5,071
F2037	5,101
F2038	5,134

Fiscal Year	Light Industrial Reference Forecast (GWh)
F2039	5,172
F2040	5,215
F2041	5,279
Compound Annual Growth Rates	
5-year History CAGR (F15 - F20)	0.4%
5-year CAGR (F20 - F25)	2.3%
10-year CAGR (F20 - F30)	1.3%
20-year CAGR (F20 - F40)	1.0%

5.4 LIGHT INDUSTRIAL UNCERTAINTIES

The Lignt Industrial Reference Load Forecast represents an aggregation of model projections, sub-sector specific customer loads, incremental new loads, and other adjustments.

For the other sub-sector portion of the large industrial forecast there are uncertainties associated with GDP as the key economic growth driver. For this sub-sector, the regression model we have used to develop the sales projection is statistically robust (no autocorrelation) and has a good fit to the historical data (high R-square value). However, since the forecast largely relies upon the GDP forecast, there is a risk that actual GDP growth may vary from forecast. The COVID-19 pandemic's impact on provincial GDP adds further uncertainty. In addition, the other light industrial sub-sector is largely composed of manufacturing loads. These loads may respond differently to other factors such as tariffs, exchange rates, technology changes and commodity prices which could impact sales. This also ho lds true for the forestry, mining and oil and gas light industrial sub-sectors.

For discrete new loads there are uncertainties not only with respect to the likelihood those loads will materialize, but also their timing. Key examples include:

- Uncertain growth potential for the cannabis industry.
- Uncertain timing of loads associated with major projects under construction. We anticipate that these loads will materialize but they could vary over the short term based on construction schedules and when construction will begin to ramp up.

For the light industrial loads related to the other sub-sector, the forecast largely relies upon the GDP forecast, there is a risk that actual GDP growth may vary from forecast.

The high and low forecasts are developed to capture some of this uncertainty. Further information on the light industrial high and low forecasts is provided in section 8.3.3

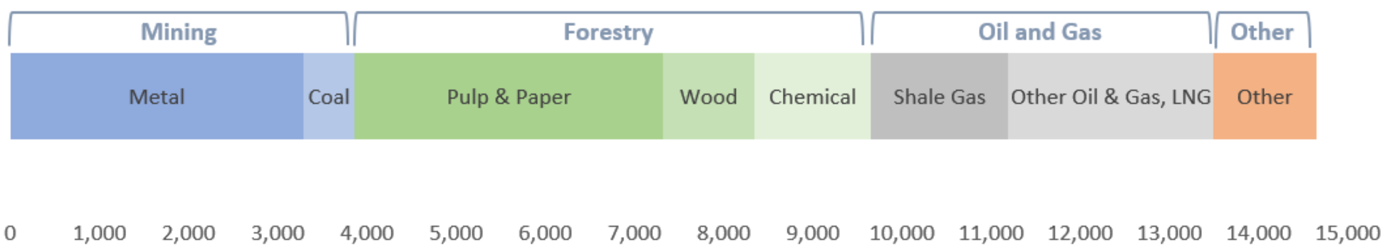
6.0 Large Industrial Forecast

6.1 LARGE INDUSTRIAL SECTOR DESCRIPTION

The large industrial sector is comprised of about 190 customers that account for about 26 per cent of BC Hydro's total firm sales. The individual customers are organized into four main sub-sectors: mining, forestry, oil and gas (including LNG), and other large industrial customers. While light industrial customers are connected at distribution voltages, large industrial customers are connected at transmission voltages. Most of our large industrial customers are involved in extracting, processing and manufacturing resource-based commodities, which are largely exported outside B.C. Export volumes can vary from year to year in response to market forces and consequently, electricity sales to this sector can also vary.

Figure 6-1 below shows the segmentation of the large industrial sector and relative size of load based on fiscal 2020 actuals.

Figure 6-1 - Large Industrial Sub-Sectors and Segments – Fiscal 2020 Actuals (GWh)

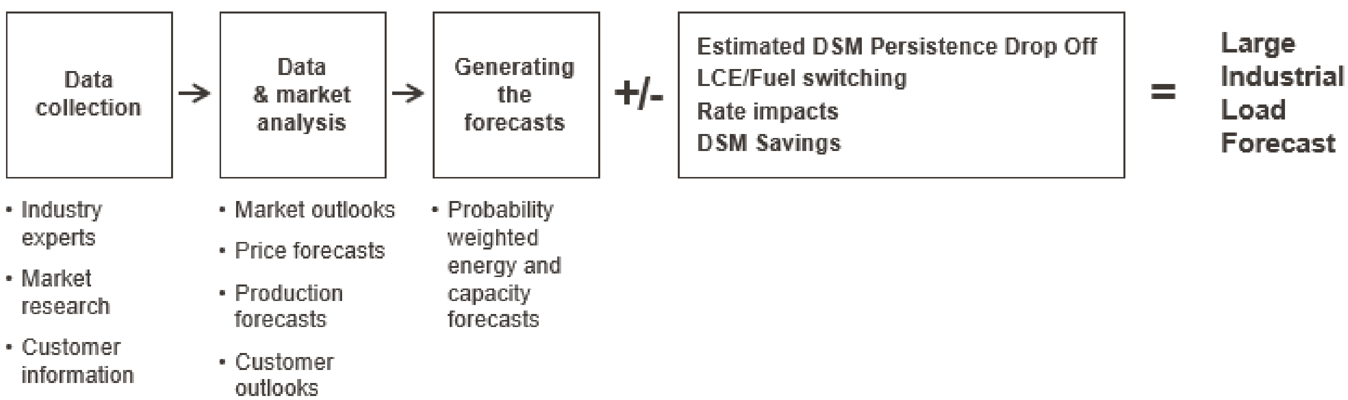


6.2 LARGE INDUSTRIAL FORECAST METHODOLOGY

6.2.1 General Process and Build-Up

Sales to the large industrial sector are forecast on an individual customer basis then aggregated into sub-sector forecasts as shown in Figure 6-1 above. The general account-by-account process that we use to produce the large industrial load forecasts is shown in Figure 6-2.

Figure 6-2 - Large Industrial Load Forecast Process (by sub-sector)



Each of the sub-sector forecasts is primarily developed from multiple quantitative and qualitative analyses provided by both internal and external experts in addition to information provided by our customers. The forecasts are developed in a collaborative process thereby allowing for alternative perspectives to be shared. The extent to which expert inputs are applied varies across each of the major sub-sectors and is a function of market complexity and uncertainty, number of customers and magnitude of the load. The main sources of information used to develop each sub-sector forecast include the following:

- industry experts: We retain external consultants who develop production and commodity price forecasts and provide facility and sector-specific market assessments,
- market research: We subscribe to a number of services from companies that provide market research and industry analyses. We also rely on various publicly available reports from government agencies, such as the BC Oil and Gas Commission, and

- information from our customers: We use customer-specific information gathered by our Key Account Management and Load Interconnections groups, who are in contact with our customers.

Using these sources of information, we develop a probability weighting for expected sales to our current customer. This probability weighting represents a risk assessment of the likelihood of future sales increasing, decreasing or remaining steady. For each potential new customer, these same sources of information are used to develop similar probability weightings to forecast if and when new demand will materialize.

Each of these probability weightings represents our professional judgement based on the synthesis of information from our sources as well as factors that are considered when assigning probability weightings. Examples of factors considered include:

- how far a customer has passed through our interconnection processes,
- the status of the customer's regulatory/approval permits and project financing,
- BC Hydro's ability to meet the customer's requested in-service date,
- consultant mill, facility and market assessments, where applicable,
- the market outlook for the customer's products,
- the credit and financial viability of the customer,
- the impact of electricity costs on the customer,[5] and
- the likelihood that the customer will take electricity supply from BC Hydro instead of self-supplying their power needs.

Due to commercial sensitivities, individual account assessments are kept confidential. To maintain this confidentiality the large industrial forecast is aggregated by sub-sector.

In developing the large industrial load forecast, we have included the estimated DSM persistence drop off in each of the large industrial sub-sectors based on analysis by our Conservation and Energy Management group. We now assume that once an efficiency project has been implemented, the customer will continue to replace like for like equipment at the end of its lifecycle.

As with the residential and commercial sectors, the large industrial sector build-up includes adjustment for LCE/fuel switching, rate impacts and DSM. LCE/fuel switching is a relatively small portion of the overall forecast large industrial LCE loads and the majority of the large industrial LCE loads are attributed to two specific customer projects. For confidentiality reasons these project loads are embedded within the oil and gas sub-sector forecast.

6.2.2 Integrating Top-Down and Bottom-Up Information

For some large industrial segments, probability weightings are developed by assessing customer operations (i.e., bottom-up) in the context of the customer's broader market conditions (i.e., top-down). This process entails the following:

Bottom-Up: In order to determine how much energy each customer needs, we typically perform a bottom-up analysis for their various operations. This analysis assesses the historical (or requested) energy usage and compares it to the volume of product a customer produces to determine load or intensity factors. We obtain this information from internal BC Hydro sources, our customers, external consultants or industry reports.

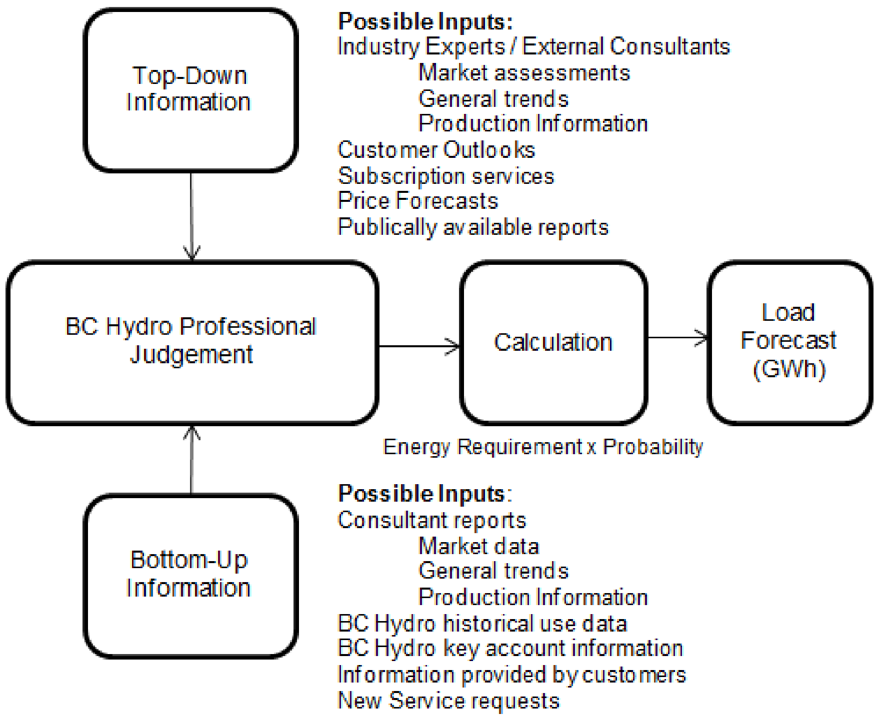
Top-Down. Industrial customers are subject to changing market conditions and it is important to understand how macro-economic influences will impact their business and ultimately their energy needs. The top-down analysis performed is the application of a supply, demand and price analysis of the markets where our industrial customers are expected to sell their products and the consideration of

[5] This factor incorporates the impacts of future electricity costs on electricity demand relative to how much their electricity costs are to overall cost of production on a sub-sector wide basis. This is separate from, but needs to be considered along with, price elasticity when assessing the overall impacts of future electricity prices.

how these market influences will impact their operations. Information from a variety of external sources is considered to shape the high-level assessment of the market.

Figure 6-3 below shows how the top-down, bottom-up analysis is conducted.

Figure 6-3 General Overview of Top-Down, Bottom-Up Forecasting Methodology



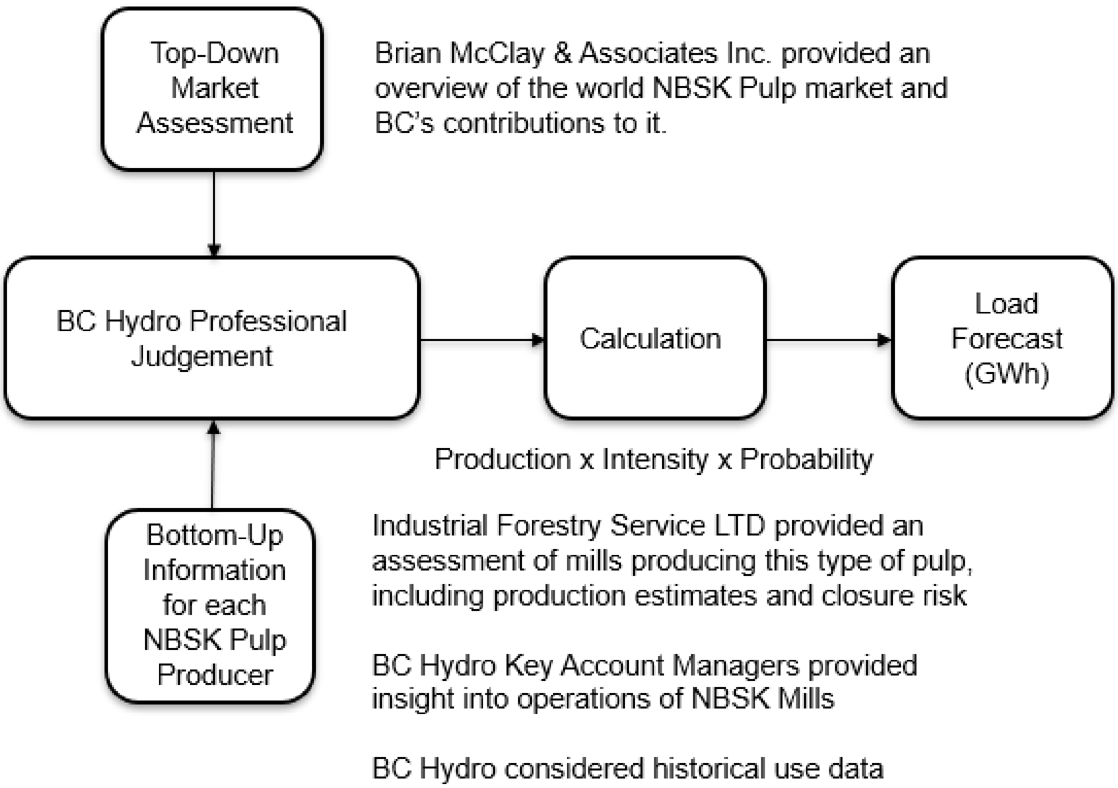
The application of this general methodology varies by subsector and segment. Figure 6-4 below shows a breakdown of the large industrial sector. The bottom-up analysis is done at the lowest level shown for each product/service line or sub-segment. The top-down analysis is performed for operations marked “Yes” under the column entitled, “T-D Done?”

Figure 6-4 BC Hydro Large Industrial Forecast Breakdown

Sector	Sub-sector	Segment	Sub-segment	Product/Service Line	T-D Done?
Large Industrial	Forestry	Pulp & Paper	Kraft	NBSK Pulp	Yes
				Self Generation	n/a
				Packaging	n/a
				Cellulose Fillament	Yes
				Biofuel	Yes
			Publication Papers	Thermal Mechanical P	Yes
				Kraft	Yes
				Newsprint	Yes
				Super Calendar	Yes
				Towelling	Yes
				Uncoated Groundwood	Yes
				Lightweight Coated	Yes
				Self Generation	n/a
			BCTMP	BCTMP	Yes
				Self Generation	n/a
			Other	Tissue & Other	Yes
		Wood Products	Sawmill	Sawmill	Yes
				Self Generation	n/a
				Chip	No
			Panel		Yes
			Pellet		Yes
		Chemical	Sodium Chlorate		No
			Caustic Soda		No
			Hydrogen Peroxide		No
			Chlorine		No
			Hydrochloric Acid		No
			Hydrogen		No
	Oil & Gas	Shale Gas	Shale Gas and Liquids		Yes
		Other Large Oil & Gas Operations	Propane Terminals		Yes
			Gas Pipelines/Compressor Stations		Yes
			Gas Processors		No
			Convential Gas		No
			Oil Pipelines		Yes
			Oil Refineries/Tank Farms		No
			Oil		Yes
			LNG Terminals		Yes
	Mining	Metal	Copper		Yes
			Gold		Yes
			Molybdenum		Yes
		Coal	Metallurgical		Yes
	Other		Universities		No
			Cement		No
			Manufacturing		No
			Ports & Terminals		No
			Airport		No
			Cryptocurrency/Data Centers		No

To illustrate how the top-down and bottom-up methodologies are applied, Figure 6-5 below shows an example of how Figure 6.3 is applied to a specific product line: Northern Bleached Softwood Kraft (NBSK) Pulp. Figure 6-4 shows this as a product line in the forestry sub-sector, pulp and paper segment, Kraft sub-segment.

Figure 6-5 Example of Application of Top-Down, Bottom-Up Forecast Methodology to NBSK Pulp



Similar approaches are applied to varying degrees for the sub-segments and product/service lines outlined in Figure 6-4 to build out the Large Industrial Reference Load Forecast.

6.2.3 Addressing Potential for Bias in the Large Industrial Forecast

BC Hydro acknowledges that there is a potential for bias in developing the large industrial forecast, such as information reported by customers. Measures are taken to reduce or eliminate this type of bias in the forecast.[6]

In general, the methodologies used to develop the light and large industrial load forecasts fo r our major sub sectors (i.e., forestry, oil and gas, mining) are not susceptible to the weakness of an "informed opinion" from an "expert" or from the customer. This is because those forecasts are primarily developed from multiple quantitative and qualitative analyses provided by both internal and external experts in addition to information provided by our customers. In other words, our major subsector forecasts are developed from multiple qualified expert inputs, including from outside parties. The forecasts are developed in a collaborative process thereby allowing for alternative perspectives to be shared.

[6] Further information can be found in BC Hydro's response to BCUC IR 1.9.1.1 to the Fiscal 2020 – Fiscal 2021 Revenue Requirements Application.

The extent to which expert inputs are applied varies across each of the major subsectors and is a function of market complexity and uncertainty, number of customers and magnitude of the load.

BC Hydro detects and addresses potential bias in large industrial customer forecasts through the means described in the sections below.

6.2.3.1 Forecast Methodology

As described in sections 6.2.1 and 6.2.2, the largest and most complex large industrial sub-sectors are primarily developed from multiple quantitative and qualitative analyses provided by both internal and external experts in addition to information provided by our customers.

There are customer segments, including those within the Other Large Industrial sub-sector, in which the load forecasts primarily rely on historical sales data, information provided by our customers regarding their long-term plans and electricity needs, and key account management's professional judgment. BC Hydro believes the approach for these customer segments are appropriate for the following reasons:

- The subsector is a small component of BC Hydro's overall load (approximately 1,200 GWh per year);
- The subsector is primarily made up of long-standing customers with relatively stable historical sales; and
- The financial costs needed to develop external assessments for each of the diverse segments making up the subsector are not justified given the first two bullets above.

6.2.3.2 Customer Application Process

For customer requests, customers refine their load requirements throughout the load interconnection process with BC Hydro's assistance. The process begins with the customer completing a Transmission Voltage Customer Interconnection Data Form. This form requires applicants to itemize plant equipment with horsepower – information that can be used to reconfirm load requirements. Next, BC Hydro works collaboratively with the customer to complete a series of interconnection studies that helps them refine their load requirements.

The interconnection process has a built-in incentive for the customer to avoid overstating their load requirements. This is because the customer will likely trigger major system upgrades if they request a greater load than what they truly need, and for which they will be financially responsible.

For example, once BC Hydro provides information on potential system upgrades in the early stages of interconnection process, the customers often review their load requirements and come back with more accurate numbers.

Comparison Against External Sources

When information is available, a project level review of the data and market analysis can be undertaken to allow for an assessment of specific customer load requests and associated timing. This is undertaken internally or via third party market research organizations. Examples of the types of information reviewed can include environmental or other permit applications and publicly disclosed capital expenditure plans.

6.2.3.3 Variance Analysis

Each month BC Hydro conducts a forecast review process where each large industrial customer's forecast is compared against the actual load. This review is a cross departmental process involving the Customer Service, Finance and Load Forecast departments. Material biases resulting in over-stated loads would result in obvious large variances that would be identified and addressed in subsequent forecasts.

6.2.3.4 Internal Reviews

Draft versions of the load forecast undergo multiple levels of internal inter-departmental reviews starting at lower levels of departments and progressively elevating to senior management. These reviews, among other things, seek to address potential bias in customer self-reporting.

6.2.3.5 External Reviews

External reviews occur by way of processes such as the August 2017 Load Forecasting Audit. These processes support external review of the underlying assumptions of the load forecast and its key drivers and identify and resolve bias from customer self-reporting.

6.2.3.6 Continuous Improvement Approach

The BC Hydro Load Forecast department is periodically audited, and it undertakes a continuous process improvement approach. This approach helps to address potential bias in customer self-reporting and allows BC Hydro to consider opportunities to improve forecast accuracy.

6.2.4 Binary Approach for First Three Years of the Forecast

Consistent with our more recent load forecasts, we apply a binary approach for the first three years of the forecast (F21-23). The binary method results in a discrete projection (i.e., in or out) of load and revenues. This approach is applied as follows:

- We continue to undertake probability assessments on an individual customer account basis.
- Where the dominant risk factor amongst all others is closure risk, customer loads included in the forecast are reflected at either their full expected load (weighted at 100 per cent probability) or zero load (weighted at 0 per cent) for the period fiscal 2019 to fiscal 2021, depending on whether the closure risk is assessed as being low or high.
- Where the main risk factor is start up likelihood, only high likelihood projects are included at their full expected load in the period fiscal 2021 to fiscal 2023. For these highly likely projects we also consider project schedule risk as part of the binary assessment. For example, there may be uncertainty on when a project actually comes into service relative to the customer requested in service date. In these situations, we will exercise our professional judgement in deciding whether to reflect the full expected load at a later date than that requested by the customer. If we determine that there is a reasonable likelihood the actual in service date will occur beyond the customer requested in service date, the full expected load (i.e., weighted at 100 per cent) will be reflected at that later date in the forecast and at zero load (i.e., weighted at 0 per cent) prior to that date.

We also made assumptions about the extent to which commodity prices will continue to be depressed as a result of the COVID-19 pandemic impacts on the global economy and then, working with BC Hydro's Key Account Management department, undertaking a customer-by-customer assessment.

As part of this assessment we communicated directly with some of our large industrial customers to assess ongoing impacts of COVID-19 pandemic on individual accounts. That allowed for an assessment of a range of possible outcomes, including:

- A temporary reduction in consumption in major industries such as forestry;
- Permanent closures of industrial facilities; and
- Potential delays in the construction of major infrastructure projects.

For the forestry and oil and gas subsectors, we also considered the exacerbating effects of other market pressures (i.e., fibre supply shortages on forestry; global oil price war on oil and gas).

BC Hydro relied on professional judgment and experience of the Load Forecast and Key Account Management departments.

6.3 LARGE INDUSTRIAL FORECASTS RESULTS

6.3.1 Large Industrial Unadjusted Forecast

The Large Industrial Reference Load forecast is an aggregation of all sub-sector and segment forecasts. Table 6-1 below provides the sector's sale history and Reference Load Forecast before adjustments for rates and DSM.

Table 6-1 Large Industrial Reference Load Forecast Before Adjustments

Fiscal Year	Mining		Forestry			Oil and Gas		Other	Total
	Metal Mines (GWh)	Metallurgical Coal Mines (GWh)	Pulp and Paper (GWh)	Wood Products (GWh)	Chemical (GWh)	Shale Gas (GWh)	Other Oil and Gas (GWh)	Large Industrial (GWh)[1]	Large Industrial (GWh)
Forecast									
F2021	3,347	608	2,686	1,039	1,249	1,448	790	1,076	12,243
F2022	3,432	640	2,546	1,113	1,303	1,564	850	1,177	12,625
F2023	3,485	646	2,549	1,175	1,368	1,985	1,002	1,234	13,445
F2024	3,488	656	2,494	1,116	1,368	2,264	1,732	1,244	14,363
F2025	3,572	655	2,439	1,090	1,368	2,559	2,526	1,185	15,394
F2026	3,637	655	2,453	1,090	1,368	2,765	3,240	1,135	16,342
F2027	3,792	675	2,453	1,090	1,368	2,920	3,386	1,145	16,828
F2028	3,891	735	2,453	1,088	1,368	2,985	3,607	1,145	17,272
F2029	3,891	735	2,453	1,088	1,368	3,047	3,607	1,145	17,334
F2030	3,891	746	2,453	1,088	1,368	3,116	3,607	1,145	17,414
F2031	3,891	746	2,453	1,088	1,368	3,154	3,607	1,159	17,466
F2032	3,891	853	2,453	1,088	1,368	3,156	3,607	1,167	17,583
F2033	3,891	853	2,453	1,088	1,368	3,158	3,607	1,178	17,596
F2034	3,891	853	2,453	1,088	1,368	3,158	3,607	1,186	17,603
F2035	3,891	853	2,453	1,088	1,368	3,158	3,607	1,196	17,614
F2036	3,891	853	2,453	1,088	1,368	3,158	3,607	1,204	17,622
F2037	3,891	853	2,453	1,088	1,368	3,158	3,607	1,215	17,632
F2038	3,891	853	2,453	1,088	1,368	3,158	3,607	1,223	17,640
F2039	3,891	853	2,453	1,088	1,368	3,158	3,607	1,234	17,651
F2040	3,891	853	2,453	1,088	1,368	3,158	3,607	1,242	17,660
F2041	3,891	853	2,453	1,088	1,368	3,158	3,607	1,254	17,672

Table notes:

1. Values are based on customer forecasts and do not include any load additions or adjustments.
2. Historical values are not provided in this table because they do not provide a relevant comparison to the unadjusted forecast.

6.3.2 Large Industrial Forecast Build-Up

As with the other sectors, adjustments are made to derive the final large industrial forecast. Table 6-2 below shows the details of the large industrial load forecast build up for select years as examples to show how the Large Industrial Reference Load Forecast is derived.

Table 6-2 Large Industrial Reference Load Forecast Build-up

Fiscal Year	Large Industrial Customer Forecast Before Adjustments (GWh)	Estimated DSM Persistence Drop Off (GWh)	Fuel Switching Load Additions (GWh)	Rate Impacts (GWh)	DSM (GWh)	Large Industrial Load Forecast After Adjustments (GWh)
F2021	12,243	0	3	30	(111)	12,165
F2022	12,625	0	20	39	(246)	12,437
F2023	13,445	0	36	24	(322)	13,183
F2024	14,363	0	36	36	(393)	14,042
F2025	15,394	(18)	36	21	(451)	14,982
F2026	16,342	(21)	36	48	(509)	15,896
F2031	17,466	(46)	35	51	(753)	16,754
F2036	17,622	(183)	24	51	(824)	16,690
F2041	17,672	(394)	11	51	(764)	16,575

6.3.3 Large Industrial Reference Forecast

Table 6-3 below provides the Large Industrial Oil and Gas (including LNG) sector sales history and Reference Load Forecast load after LCE/fuel switching load additions and adjustments for rate impacts and DSM. The DSM plan provides estimates of savings at a sub-sector level so the allocation of DSM to the segments shown below is an approximation.

Table 6-3 Large Industrial Sales History and Reference Load Forecast After Adjustments

Fiscal Year	Mining		Forestry			Oil and Gas		Other Large Industrial (GWh)	Total Large Industrial (GWh)
	Metal Mines (GWh)	Metallurgical Coal Mines (GWh)	Pulp and Paper (GWh)	Wood Products (GWh)	Chemical (GWh)	Shale Gas (GWh)	Other Oil and Gas (GWh)		
Actual									
F2015	3,247	560	5,262	1,155	1,541	142	973	1,173	14,055
F2016	3,338	544	4,726	1,208	1,456	440	836	1,149	13,698
F2017	3,320	562	4,173	1,141	1,409	555	818	1,126	13,106
F2018	3,291	589	4,234	1,243	1,477	710	797	1,171	13,513
F2019	3,270	577	3,997	1,213	1,309	1,416	861	1,123	13,766
F2020	3,285	578	3,561	1,018	1,313	1,540	794	1,146	13,235
Forecast									
F2021	3,320	603	2,651	1,034	1,252	1,444	788	1,072	12,165
F2022	3,367	627	2,476	1,100	1,307	1,552	844	1,165	12,437
F2023	3,405	628	2,449	1,157	1,371	1,966	992	1,215	13,183
F2024	3,388	634	2,370	1,094	1,372	2,246	1,718	1,220	14,042
F2025	3,443	629	2,284	1,060	1,370	2,538	2,504	1,154	14,982
F2026	3,494	627	2,279	1,057	1,372	2,748	3,218	1,100	15,896
F2027	3,634	644	2,262	1,054	1,372	2,901	3,362	1,106	16,335
F2028	3,723	700	2,248	1,049	1,372	2,965	3,581	1,103	16,741
F2029	3,705	697	2,227	1,044	1,372	3,025	3,577	1,098	16,745
F2030	3,683	703	2,202	1,039	1,372	3,091	3,574	1,094	16,757
F2031	3,665	699	2,181	1,035	1,372	3,126	3,570	1,104	16,754
F2032	3,658	798	2,166	1,031	1,372	3,127	3,567	1,109	16,828
F2033	3,635	795	2,152	1,028	1,372	3,128	3,563	1,118	16,791
F2034	3,622	792	2,137	1,025	1,372	3,128	3,560	1,122	16,759
F2035	3,609	789	2,122	1,022	1,372	3,127	3,556	1,130	16,727
F2036	3,595	786	2,105	1,019	1,372	3,127	3,551	1,135	16,690
F2037	3,581	783	2,076	1,015	1,372	3,127	3,547	1,143	16,645
F2038	3,567	780	2,060	1,012	1,372	3,126	3,543	1,148	16,608

F2039	3,553	777	2,044	1,008	1,372	3,126	3,538	1,157	16,577
F2040	3,540	774	2,028	1,005	1,372	3,126	3,534	1,163	16,543
F2041	3,546	776	2,036	1,007	1,372	3,130	3,532	1,175	16,575
Compound Annual Growth Rates									
5-year History CAGR (F15 - F20)	0.2%	0.6%	(7.5%)	(2.5%)	(3.2%)	61.1%	(4.0%)	(0.5%)	(1.2%)
5-year CAGR (F20 - F25)	0.9%	1.7%	(8.5%)	0.8%	0.9%	10.5%	25.8%	0.1%	2.5%
10-year CAGR (F20 - F30)	1.2%	2.0%	(4.7%)	0.2%	0.4%	7.2%	16.2%	(0.5%)	2.4%
20-year CAGR (F20 - F40)	0.4%	1.5%	(2.8%)	(0.1%)	0.2%	3.6%	7.8%	0.1%	1.1%

Table notes:

1. Values include all load addtions and adjustments.

6.4 MINING

As a result of our market outlook and internal information related to service requests from potential new customers, the reference case projects modest growth in the mining sub-sector load over the next twenty years. The growth comes from increased production, equipment upgrades and new mines entering the forecast, but it’s partially offset by some of the existing mines reaching end of life. The total reference case load in the mining sub-sector in fiscal 2041 is projected to be 4,322 GWh, up 729 GWh from 3,863 GWh recorded in fiscal 2020. A number of uncertainties exist, which are reflected in the high and low forecasts.

6.4.1 Mining Sub-sector Description

The mining sub-sector accounts for about 31 per cent of sales to the large industrial sector. It is categorized into two segments: metal and metallurgical coal mines. Demand from metal mining makes up 85 per cent of the total sales in the mining sector. Since metal mining represents the vast majority of the mining load for BC Hydro, the drivers of metal mining have the most influence on the total mining load.

Metal mines typically consume more electricity than metallurgical coal mines, due to the energy required in the comminution process (crushing and grinding ore to extract the target minerals). Electricity used in metal mining operations typically represents about 10 to 15 per cent of total production costs. The metal mines in B.C. produce predominantly copper with gold, molybdenum, and silver as common secondary products. Two operating mines - Brucejack and New Afton - list gold, as the main product.

Metallurgical coal is an export commodity which is sold worldwide to integrated steel mills for steel-making purposes. Metallurgical coal mines consume less electricity than metal mines, due to the softer sedimentary nature of these deposits. Only crushing is required to break up the rock and energy intensive milling is not required. Electricity used in metallurgical coal operations typically represents about 5 per cent of production costs.

Growth in B.C.’s mining industry is linked to commodity prices, which can be volatile and cyclical. In general, demand is driven by economic growth within parts of Asia and the relative global supply/demand balance for copper, metallurgical coal, gold and to a lesser extent molybdenum. China is currently responsible for about 50 per cent of global copper demand. Other factors that impact mining sales and the development of new mines include the availability of financing, regulatory and environmental approvals, and First Nations considerations.

The mining sector is also characterized by the long timeline required to bring a project from exploration stage into production.

The metals commodity boom between 2009 and 2011 triggered an increase in mine development activity in British Columbia. This was followed by an economic downturn in 2013-2016, as growth in China slowed down. Copper prices stabilized somewhat during 2017-2019, but the beginning of the COVID-19 pandemic brought a sharp but short-lived decline in commodity prices. As China emerged relatively quickly from the lockdown and demand for copper and other commodities strengthened over the summer of 2020, copper prices recovered and exceeded pre-pandemic levels.

Due to long construction periods and additional time to ramp up or ramp down production, electricity sales in the mining sector typically lag commodity prices. Restarts and upgrades at existing operations are generally the fastest response to positive price signals, followed by greenfield additions. Prolonged low-price environments may lead to shutdowns, but most closures have also a built-in lag effect as metal miners continue to run the electric intensive mills to process stockpiles months after the shutdown of pit operations.

The recent history of mining load in B.C. is a good example of the lag effect. The commodity price boom in 2009-2011 prompted upgrades at existing operations (e.g., Gibraltar, Endako, Highland Valley) accompanied by brownfield restarts (Copper Mountain, New Afton) and greenfield additions (Mt Milligan, Red Chris Brucejack). This resulted in the metal mining load increasing by approximately 40 per cent between fiscal 2011 and fiscal 2015, despite the commodity market being in a pronounced downturn. The ramp up in mining load after fiscal 2016 was offset by shutdowns at Endako, Huckleberry and Mount Polley mines due to low commodity prices. This resulted in a flat profile for mining load between fiscal 2016 and fiscal 2020.

Mining exploration activity in the province increased in 2020 following years of reduced activity. Exploration expenditures across the province increased by 28 per cent year-over-year to $422 million close to the highs experienced in 2011 and 2013.

6.4.2 Mining Forecast Methodology

The mining sector's sales are forecast on an individual customer account basis, in line with the large industrial sector methodology. There are two independent methods of deriving the forecast of electricity sales for mining customers.

The primary forecast method is the product of expected peak demand, load factor, and probability. The load factor is a measure of the utilization rate, or efficiency of electrical energy usage. In the case of existing customers, historical consumption information is used as the starting point and is updated with new information (such as equipment upgrades). The probability weighting, which is informed by the criteria outlined in section 6.2 include factors such as the project's economics, availability of financing, regulatory progress and BC Hydro interconnection status. A mine's economics is analyzed in the context of the global market. The mining forecast includes closure risk for existing customers.

The secondary forecast method uses production, electricity intensity and probability. The production data is informed by the third-party subscription service and the electricity intensity is derived from our internal sources.

For the current metal mining load forecast, we rely on the Wood Mackenzie copper mining subscription and Consensus Economics price forecast to support the development of the metal mining forecast. We also use public reports from the Ministry of Energy, Mines and Low Carbon Innovation (Ministry), Thompson Reuters, PricewaterhouseCoopers, Deloitte, company public reports and information gathered by our Key Account Management and Load Interconnections business units.

For the metallurgical coal mining forecast we rely on Consensus Economics, the Ministry, company public reports and internal information.

6.4.3 Metal Mining Segment

6.4.3.1 Metal Mining Segment Description

In the long term, electricity sales to metal mines are tied to price expectations for copper and gold and to a lesser extent, molybdenum and silver. The prices of these commodities are influenced by global demand and supply and the state of the global economies. In the short term, month-to-month electricity sales to metal mines are relatively independent of commodity price fluctuations because these mines are fixed-cost operations, running on a continuous basis. Since the most of B.C. metal mining production is exported, mining sales are not overly dependent on domestic economic activity, but rather correlated to the global economy. The top destinations for B.C. mining exports include Japan, the United States, China and South Korea.

6.4.3.2 Metal Mining Forecast Results

Over the five years ending fiscal 2020, sales to the metal mining segment remained relatively flat. The increase from projects ramping up production such as Brucejack or Red Chris was offset by the loss of several metal mining customers (Huckleberry, Endako, Mount Polley) due to lower commodity prices. Table 6-4 shows the history and forecast of metal mining sales after fuel switching load additions and adjustments for rate impacts and DSM.

Table 6-4 Metal Mining Segment Sales History and Reference Load Forecast After Adjustments

Fiscal Year	Metal Mining Reference Forecast (GWh)
Actual	
F2015	3,247
F2016	3,338
F2017	3,320
F2018	3,291
F2019	3,270
F2020	3,285
Forecast	
F2021	3,320
F2022	3,367
F2023	3,405
F2024	3,388
F2025	3,443
F2026	3,494
F2027	3,634
F2028	3,723
F2029	3,705
F2030	3,683
F2031	3,665
F2032	3,658
F2033	3,635
F2034	3,622
F2035	3,609
F2036	3,595
F2037	3,581
F2038	3,567
F2039	3,553
F2040	3,540
F2041	3,546
Compound Annual Growth Rates	
5-year History CAGR (F15 - F20)	0.2%
5-year CAGR (F20 - F25)	0.9%
10-year CAGR (F20 - F30)	1.2%
20-year CAGR (F20 - F40)	0.4%

While the COVID-19 pandemic reduced copper prices in fiscal 2021, it was relatively short-lived. As a result, B.C. copper mines were able to maintain their normal production levels with only minor disruptions.

Table 6-5 Copper Reference Price Forecast

Fiscal Year	Copper Price Forecast ($/tonne)	Copper Price Forecast ($/lb)
Actual		
F2015	6,857	3.1
F2016	5,502	2.5
F2017	4,863	2.2
F2018	6,164	2.8
F2019	6,526	3
F2020	6,009	2.7
Forecast		
F2021	5,685	2.6
F2022	6,123	2.8
F2023	6,329	2.9
F2024	6,494	2.9
F2025	6,724	3
F2026-F2041	6,605	3

The copper mining reference forecast is based on a favourable short- and long-term outlook for both copper and gold (commonly found BC copper ore bodies) and internal information related to service requests from potential new customers. We are expecting approximately 250 GWh growth in the metal mining load between fiscal 2020 and fiscal 2041. Some equipment upgrades to existing operations are expected to occur between fiscal 2021 and 2025. However, any potential (probability weighted) new mining loads after fiscal 2026 are offset by expected end of life shutdowns to several existing customers. The metal mining load in fiscal 2041 increases to approximately 3,550 GWh from the current level of 3,300 GWh in fiscal 2020.

The copper market outlook[7] underpinning the reference forecast is summarized as follows:

- although high volatility is inherent with metal prices, the long-term average annual copper price is expected to continue around $3/lb as global demand grows at a moderate pace driven by construction activity in China and global electrification of various sectors (transportation, manufacturing). Reference metallurgical coal prices are provided in Table 7.2.
- short and long term COVID-19 pandemic impacts on the metal mining sector are assumed to be negligible.

At these price levels, BC Hydro expects existing customers to operate normally and there is low incentive to bring new projects into production.

[7] Copper market outlook is informed by analyst judgment, Wood Mackenzie subscription and other sources described in the methodology section.

6.4.3.3 Metal Mining Uncertainties

The major risks and uncertainties around the metal mine segment over the forecast period include:

- price volatility, boom and bust cycles,
- COVID-19 pandemic impact on world economies, particularly China,
- additional mining sector electrification associated with meeting provincial greenhouse gas (GHG) emission reduction targets,
- closures due to accidents,
- rising trend in trade protectionism which impacts global economic growth,
- demand erosion due to substitution effects from other sources (aluminium, steel, composite materials) and rise in scrap recovery,
- higher/lower than anticipated global economic growth mirrored in increased/decreased demand for metals,
- higher/lower than anticipated electrification of transportation and manufacturing resulting in increased metal demand,
- outcome of future environmental assessment applications from a number of proposed mines, and
- skilled labour shortages for mining companies due to aging workforce and competition with other sectors.

The high and low forecasts are developed to capture some of this uncertainty. Further information on the metal mining high and low forecasts is provided in section 8.2.4.

6.4.4 Metallurgical Coal Segment

6.4.4.1 Metallurgical Coal Segment Description

Metallurgical coal mines account for about 15 per cent of BC Hydro's total mining sector sales. Teck's Elk Valley Coal Partnership in southeast B.C. supplies about one sixth of the world's seaborne metallurgical coal market. Metallurgical coal is also produced in northeastern B.C.

In the long term, sales are tied to price expectations for metallurgical coal. Export markets for B.C. metallurgical coal include China, Japan, South Korea, and to a lesser extent India, Europe, South America and the United States. As a result, the state of B.C.'s economy has little effect on metallurgical coal sales; however, provincial regulatory and policy actions can have an impact.

6.4.4.2 Metallurgical Coal Forecast Results

Over the past five years ending fiscal 2020, sales to the metallurgical coal segment increased by 18 GWh or 0.6 per cent. This increase was caused by equipment upgrades at existing customer sites and increased production which offset the closure of one of the existing Teck coal mining operations, Coal Mountain. Table 6-6 shows the history and forecast of metallurgical coal sales after fuel switching load additions and adjustments for rate impacts and DSM.

Table 6-6 Metallurgical Coal Mining Segment Sales History and Reference Load Forecast After Adjustments

Fiscal Year	Metallurgical Coal Mining Reference Forecast (GWh)
Actual	
F2015	560
F2016	544
F2017	562
F2018	589
F2019	574
F2020	578
Forecast	
F2021	603
F2022	627
F2023	628
F2024	634
F2025	629
F2026	627
F2027	644
F2028	700
F2029	697
F2030	703
F2031	699
F2032	798
F2033	795
F2034	792
F2035	789
F2036	786
F2037	783
F2038	780
F2039	777
F2040	774
F2041	776
Compound Annual Growth Rates	
5-year History CAGR (F15 - F20)	0.6%
5-year CAGR (F20 - F25)	1.7%
10-year CAGR (F20 - F30)	2.0%
20-year CAGR (F20 - F40)	1.5%

While the COVID-19 pandemic reduced metallurgical coal prices in fiscal 2021, it was relatively short-lived. B.C. metallurgical coal mines were able to maintain their normal production levels, as mines were able to continue their activity with only minor disruptions.

The metallurgical coal mining reference forecast is based on a favourable short- and long-term market outlook and internal information related to service requests from potential new customers, we are expecting approximately 200 GWh growth between fiscal 2020 and fiscal 2041. The increase is driven by equipment upgrades and increased production at existing operations.

The metallurgical coal market outlook underpinning our reference forecast is summarized as follows:

- metallurgical coal prices have gradually decreased from 2019 levels and long-term price is assumed to settle at approximately $USD140-145/tonne within the next few years, and

- short and long term COVID-19 impacts are assumed to be negligible.

At this price level, we expect existing metallurgical coal operations to maintain or increase production levels and complete equipment upgrades. No new mines are assumed to occur over the forecast period.

Figure 6-7 below illustrates the metallurgical coal price assumptions used for the December 2020 reference forecast:

Table 6-7 Metallurgical Coal Reference Price Forecast

Fiscal Year	Metallurgical Coal Price Forecast ($/tonne)
Actual	
F2015	125
F2016	102
F2017	119
F2018	190
F2019	192
F2020	183
Forecast	
F2021	133
F2022	141
F2023	148
F2024	148
F2025	148
F2026-F2041	142

6.4.4.3 Metallurgical Coal Uncertainties

The major risks and uncertainties around the metallurgical coal segment over the forecast period include:

- global economic outlook: higher/lower than anticipated demand for steel in Asia,
- impacts of COVID-19 on world economies and demand for metallurgical coal,
- restrictions imposed by China to trade partners, such as the recent unofficial ban of Australian coals imports to China,
- supply disruptions (or expansions) in Australia. Australia accounts for roughly two-thirds of the global metallurgical coal production; Floods during the rainy season in Australia caused major supply disruptions in recent years,
- meeting environmental compliance requirements at existing operations, particularly with regards to selenium pollution,
- rail and terminal capacity constraints in B.C.,
- future regulations and policies that could impact future coal exploration or development, and
- skilled labour shortages for mining companies due to aging workforce and competition with other sectors.

The high and low forecasts are developed to capture some of this uncertainty. Further information on the mining high and low forecasts is provided in section 8.2.4.

6.4.5 Mining Reference Load Forecast

Table 6-8 provides the Large Industrial Mining sub-sector sales history and Reference Load Forecast, after adjustments.

Table 6-8 Mining Sub-sector Sales History and Reference Load Forecast After Adjustments

Fiscal Year	Mining Reference Forecast (GWh)
Actual	
F2015	3,807
F2016	3,882
F2017	3,882
F2018	3,880
F2019	3,844
F2020	3,863
Forecast	
F2021	3,924
F2022	3,994
F2023	4,033
F2024	4,022
F2025	4,072
F2026	4,121
F2027	4,279
F2028	4,424
F2029	4,401
F2030	4,386
F2031	4,365
F2032	4,455
F2033	4,430
F2034	4,415
F2035	4,398
F2036	4,381
F2037	4,364
F2038	4,347
F2039	4,331
F2040	4,314
F2041	4,322
Compound Annual Growth Rates	
5-year History CAGR (F15 - F20)	0.3%
5-year CAGR (F20 - F25)	1.1%
10-year CAGR (F20 - F30)	1.3%
20-year CAGR (F20 - F40)	0.6%

6.5 FORESTRY

6.5.1 Forestry Sub-sector Description

The forestry sub-sector's once dominant share of the large industrial sector has steadily declined over time. While still significant, the sub-sector now only accounts for about 50 per cent of sales to the large industrial sector. Forestry is categorized into the following three segments:

- pulp and paper,
- wood products, and
- chemical.

Proportionally, the pulp and paper segment comprises 61 per cent of forestry sales, chemical sales comprise 21 per cent and wood products comprise 18 per cent. Pulp production consists primarily of northern bleached softwood kraft. Paper production consists primarily of newsprint and newspaper inserts. Our chemical customers produce bleaching agents to whiten the products produced by the pulp and paper industry. They also produce cleaning and water purification agents for oil and gas producers and municipalities. In addition, our wood products customers produce lumber, panel sheets (like plywood and oriented strand board) and pellets for fuel. Products produced by the forestry sub-sector are primarily destined for the U.S., Chinese and B.C. economies. Detailed descriptions are provided within each forestry segment's description.

The methodologies used by each of the segments within this sub-sector are consistent with the methodology used for the large industrial sector. The forecasts are developed on an account by account basis.

6.5.2 Pulp and Paper

6.5.2.1 Pulp and Paper Segment Description

Sales to the pulp and paper segment represent 61 per cent of all forestry sales and 31 per cent of the total Large Industrial sector sales.

Pulp and paper consists of 19 mills located primarily in the south-western and north-eastern parts of B.C. These mills produce and export a wide variety of products including newsprint, coated and uncoated ground wood paper, bleached and unbleached Kraft, dissolving pulp, thermo-mechanical pulp (TMP), and bleached chemical-thermo-mechanical pulp (BCTMP). Historically, sales to this segment have been declining and we expect this to continue. This decline is primarily attributed to reduced demand for publication paper (newsprint and graphic paper), which is partially offset by increased demand for tissue/hygienic products and packaging grade. The COVID-19 pandemic appears to have accelerated both trends over the short term and adds another uncertainty dimension to electricity demand additional.

6.5.2.2 Pulp and Paper Methodology

While consistent with the large industrial sector forecast methodology, the pulp and paper segment forecast incorporates additional market evaluations and mill assessments. These are developed by third party industry experts. They forecast commodity supply, demand and prices in the markets where B.C.'s pulp, paper and wood products are sold. They also project B.C. regional market conditions for fibre supply (sawmill residuals, whole log chipping, etc.) and fibre demand (for bioenergy, pulp and paper and wood product mills). They consolidate these to produce mill line production forecasts and operational probability assessments to reflect a mill line's closure and start-up risk.

The production forecast and probability assessments are internally reviewed with input from a number of BC Hydro departments, including Key Account Management. Mill line load forecasts are developed by multiplying production forecasts, probability assessments, and mill line electricity intensities. Mill line forecasts are then aggregated to the plant level, which forms the customer load forecast. Customer account forecasts are then aggregated to form the pulp and paper forecast.

A number of pulp and paper mills also sell power to us under Electricity Purchase Agreements (EPAs). For those mills, the conditions of these agreements are considered for developing the customer's forecast.

The main drivers for this segment include:

- pulp and paper prices,
- economic growth and associate pulp and paper demand internationally,
- U.S. import duties on B.C. publication paper,
- regulations in China banning paper recycling which lift kraft and BCTMP prices and incent B.C. publication paper producers to convert paper lines to recycling,
- consumer preference for various pulp and paper products,
- B.C. fibre availability,
- global preferences for substitutes over B.C.'s pulp and paper products - particularly new eucalyptus pulp supply from the southern hemisphere,
- packaging e.g., folding box demand in China (a major driver for TMP), and
- new market development in China, India and emerging markets for publication papers.

6.5.2.3 Pulp and Paper Forecast Results

B.C.'s pulp and paper mills can be further categorized into the customer products they primarily produce:

- TMP and BCTMP,
- Kraft pulp,
- publication paper, and
- tissue and hygiene products.

From 2015 to 2020 sales declined by 1,701 GWh or 32 per cent. Reduced sales occurred across all four product types (arising from mill and mill line closures across the province). The decline in sales within each product type can be seen in Table 6-9 shows the history and forecast pulp and paper sales before adjusting for rate impacts and DSM savings for each product category. Rate impacts and DSM savings are applied to the consolidated pulp and paper segment forecast, so the table below shows the sub-segments before adjustments and the pulp and paper segment total before and after adjustments.

Table 6-9 Pulp and Paper Segment Reference Load Forecast Before and After Adjustments

Fiscal Year	Before Adjustments[1]					After Adjustments[2]
	BCTMP (GWh)	Kraft (GWh)	Publication Papers (GWh)	Tissue & Other (GWh)	Total Pulp and Paper Reference Forecast (GWh)	Total Pulp and Paper Reference Forecast (GWh)
Actual						
F2015	1,120	1,607	2,434	101	5262	5262
F2016	1,216	1,123	2,290	97	4726	4726
F2017	1,072	906	2,098	97	4173	4173
F2018	1,060	923	2,151	100	4234	4234
F2019	936	906	2,058	97	3,997	3,997
F2020	904	842	1,727	89	3,561	3,561
Forecast						
F2021	966	724	905	91	2,686	2,651
F2022	992	713	750	91	2,546	2,476
F2023	1,001	772	686	91	2,550	2,449
F2024	906	676	821	91	2,494	2,370
F2025	906	620	821	91	2,438	2,284
F2026	906	634	821	91	2,452	2,279
F2027	906	634	821	91	2,452	2,262
F2028	906	634	821	91	2,452	2,248
F2029	906	634	821	91	2,452	2,227
F2030	906	634	821	91	2,452	2,202
F2031	906	634	821	91	2,452	2,181
F2032	906	634	821	91	2,452	2,166
F2033	906	634	821	91	2,452	2,152
F2034	906	634	821	91	2,452	2,137
F2035	906	634	821	91	2,452	2,122
F2036	906	634	821	91	2,452	2,105
F2037	906	634	821	91	2,452	2,076
F2038	906	634	821	91	2,452	2,060
F2039	906	634	821	91	2,452	2,044
F2040	906	634	821	91	2,452	2,028
F2041	906	634	821	91	2,452	2,036
Compound Annual Growth Rates						
5-year History CAGR (F15 - F20)	(4.2%)	(12.1%)	(6.6%)	(2.5%)	(7.5%)	(7.5%)
5-year CAGR (F20 - F25)	0.0%	(5.9%)	(13.8%)	0.4%	(7.3%)	(8.5%)
10-year CAGR (F20 - F30)	0.0%	(2.8%)	(7.2%)	0.2%	(3.7%)	(4.7%)
20-year CAGR (F20 - F40)	0.0%	(1.4%)	(3.6%)	0.1%	(1.8%)	(2.8%)

Table notes:

1. Before adjustments numbers do not include fuel switching or estimated DSM persistence drop off adjustments.
2. After adjustments numbers include all adjustments for LCE/fuel switching, estimated DSM persistence drop off, rate impacts, and DSM savings.

Factors contributing to mill closures in recent years were poor market conditions, aging equipment, declining fibre availability (due to pine beetle infestation), strong competition from Kraft mills in South America, displacement of newspaper by digital media, adoption of power saving projects, and increased use of electronic media by advertisers.

Previous commodity price forecasts accurately projected a pulp price downturn. but the extent of the global market's current pulp oversupply and the depth of the downwards pricing correction was underestimated. These persistent low prices combined with ongoing fibre supply challenges resulted in production curtailments at several mills during fiscal 2020.

For future sales, the reference case assumes the COVID-19 pandemic continues to disrupt all pulp and paper markets through fiscal 2021. The reference case anticipates global GDP to return to pre-pandemic growth trends by late fiscal 2021. Over the longer term the pandemic is anticipated to accelerate existing market trends such as the decline in the use of graphic papers and the increased use of tissue/hygienic products and packaging grades. This is likely to persist over the long term given that:

- The replacement of single-use plastic products and rapidly growing e-commerce activity will drive demand higher for a widening range of F-weight packaging paperboard and Molded Fiber Products (MFP).
- Declining recovered paper (RCP) supply is creating an expanding pulp fiber gap that the virgin fibre pulp made in B.C. can help fill. As world graphic paper use drops as much as 8% year over year over the next decade, the potential supply of recovered graphic paper should shrink about 1.5 million tonnes per year. Moreover, future recovered paper supply should also be limited by accelerating e-commerce (80% of which is paper) since recycling is much less efficient from individual households than from 'bricks and mortar' stores.
- Accelerating growth in the use of household and commercial paper towels: as consumers become more hygiene conscious in the COVID-19 era, as people spend more time at home and as more electric hand dryers in public restrooms will be replaced with single-use paper towels for hygienic reasons.

For the period fiscal 2021 to fiscal 2041, reference case sales are forecast to decline by 233 GWh or nine per cent. Most of this decline occurs in fiscal 2021 due to advancing the expected closure of one major pulp mill and a permanent line closure in another mill. Over the longer-term sales are assumed to remain relatively stable as global markets return to pre-pandemic growth trends and pulp and paper prices increase in response to increasing demand of tissue, hygiene and packaging products.

The commodity price assumptions used to complete the top-down verification in the pulp and paper sector are provided in Table 6-10 below.

Table 6-10 Pulp and Paper Segment Commodity Price Forecasts

Fiscal year	Fiscal year	Kraft (US$/ADMT)	BCTMP (US$/ADMT)	Newsprint (US$/ADMT)
Actual				
F2015	$ 712	$ 530	$ 583	$ 349
F2016	$ 628	$ 404	$ 516	$ 277
F2017	$ 584	$ 430	$ 580	$ 305
F2018	$ 696	$ 582	$ 597	$ 401
F2019	$ 851	$ 593	$ 705	$ 480
F2020	$ 616	$ 476	$ 677	$ 359
Forecast				
F2021	$ 514	$ 458	$ 563	$ 362
F2022	$ 692	$ 538	$ 533	$ 446
F2023	$ 780	$ 662	$ 532	$ 446
F2024	$ 636	$ 479	$ 543	$ 446
F2025	$ 658	$ 502	$ 543	$ 446
F2026-F2041	$ 658	$ 502	$ 550	$ 487

6.5.2.4 Pulp and Paper Uncertainties

The major risks and uncertainties for pulp and paper over the forecast period include:

Upside risks:

- market opportunities for publication paper mills (e.g., converting newsprint lines to wastepaper recycling, tissue/hygiene product or packaging lines),
- BCTMP mill restart due to continued high growth trend in the packaging products market in China,
- biofuel production at B.C. Kraft mills due to growing demand for renewable fuels, and
- Kraft mill sustainability due to higher than expected fibre supply in B.C.

Downside risks:

- publication paper mill closures (from publication paper demand shrinkage in the North American market as the public continues to switch from print to electronic media),
- BCTMP mill failure to restart (caused by reduced Chinese market demand for B.C. BCTMP imports and increased reliance on lower cost, lower quality domestic producers),
- Kraft mill closures due to pulp fibre supply shortages caused by wildfires, beetle infestation and sawmill closures,
- foreign market import duties imposed by the US and/or Chinese governments on B.C. pulp and paper.

The high and low forecasts are developed to capture some of this uncertainty. Further information on the pulp and paper high and low forecasts is provided in section 8.4.4.3.

6.5.3 Wood Products

6.5.3.1 Wood Products Segment Description

Wood products sales make up 18 per cent of all the forestry sub-sector sales and 9 per cent of Large Industrial sector sales. Wood products consists of large industrial customers who use electricity to produce dimensional and structural lumber, oriented strand board, medium density fiberboard, plywood, fuel pellets, and other specialty wood products. There are 35 such mills, which are primarily located in the North and South Interior regions. B.C. mills are among the lowest cost lumber producers in the world [8].

Electricity sales to the wood products segment depends on regional B.C. lumber supply, global demand for wood products and the viability of some pulp and paper mills. Recent growth in lumber demand was driven by the growth in U.S. housing starts. However, B.C. lumber supply will be constrained by saw-log scarcity due to the mountain pipe beetle devastation and recent record wildfires in the province. Although the Ministry of Forests, Lands, Natural Resource Operations and Rural Development is undertaking measures to address these, we anticipate reductions in annual allowable cuts will be imposed such that sales to this sector will start declining around fiscal 2023.

6.5.3.2 Wood Products Methodology

Similar to the pulp and paper segment, the process for developing the wood products load forecast is based on mill line production forecasts that are determined from macro and regional market assessments developed by a number of third-party industry experts retained by BC Hydro.

[8] There are hundreds of other smaller wood products mills served on distribution service which are included in the forestry sub-sector in the light industrial sector.

Like the pulp and paper forecast, the wood products forecast is produced as a product of mill line production forecast, electricity intensity and probability for each customer operation. The loads for individual mill lines are aggregated to the entire load for the customer and all the customers forecasts are aggregated together to develop the forecast for the wood product segment.

The primary market drivers for wood products are:

- the U.S. market (for housing starts and repair and remodeling),
- the Chinese market (lumber and logs), and
- Japan (hemlock and SPF lumber).

6.5.3.3 Wood Products Forecast Results

Table 6-11 shows the history and forecast sales of the wood products segment after fuel switching load additions and adjustments for rate impacts and DSM. For the most part, sales to this segment were flat over the historical period up to fiscal 2020. However, similar to the pulp and paper segments, electricity sales declined between fiscal 2019 and fiscal 2020 as low commodity prices and fibre supply shortages resulted in both temporary and indefinite production curtailments. These year to year changes reflect the wood segments inherent volatility.

Table 6-11 Wood Products Segment Sales History and Reference Load Forecast After Adjustments

Fiscal Year	Wood Products Reference Forecast (GWh)
Actual	
F2015	1,155
F2016	1,208
F2017	1,141
F2018	1,243
F2019	1,211
F2020	1,018
Forecast	
F2021	1,034
F2022	1,100
F2023	1,157
F2024	1,094
F2025	1,060
F2026	1,057
F2027	1,054
F2028	1,049
F2029	1,044
F2030	1,039
F2031	1,035
F2032	1,031
F2033	1,028
F2034	1,025
F2035	1,022
F2036	1,019
F2037	1,015
F2038	1,012
F2039	1,008
F2040	1,005
F2041	1,007
Compound Annual Growth Rates	

Fiscal Year	Wood Products Reference Forecast (GWh)
5-year History CAGR (F15 - F20)	(2.5%)
5-year CAGR (F20 - F25)	0.8%
10-year CAGR (F20 - F30)	0.2%
20-year CAGR (F20 - F40)	(0.1%)

For future electricity sales, the reference case assumes the COVID-19 pandemic reduces global softwood lumber demand in fiscal 2021 by 5 percent relative to fiscal 2020 levels. However, BC's wood sector is assumed to be somewhat less impacted by the pandemic's effects notwithstanding its adverse impacts on the U.S. economy, which is the largest market for BC lumber. U.S. residential construction is assumed to outperform the overall economy as home improvements are one of the few places people can spend time and money while facing public health measures and new home viewings and sales have remained robust. Nevertheless, growth is assumed to be slower relative to pre-pandemic levels as households will be cautious with big uncertainties while there is so much uncertainty. Therefore, the reference case assumes end-use and lumber markets will continue to grow, but at a still slow pace. Lumber prices are assumed to be higher than pre-pandemic levels as North American production curtailments due to COVID-19 have impacted overall supply.

Over the long term, the reference case assumes a return to normal market conditions by fiscal 2022 and steady growth in the U.S. housing market through fiscal 2041.

Notwithstanding robust demand growth, the BC wood products segment is expected to remain constrained by fibre supply shortages over both the near and long term. Consequently, reference case electricity sales are assumed to flat for the fiscal 2021 to fiscal 2041 are expected to remain flat.

Electricity sales are projected to slightly increase in the short run with a decline thereafter. U.S. housing starts are expected to continue to rise through the forecast period but the U.S.-Canada softwood lumber dispute and B.C. fibre shortage (from mountain pine beetle and recent record wildfires) will raise mill production costs and put downward pressure on sales to various mills and the sector.

6.5.3.4 Wood Products Uncertainties

There are many wildcards in the wood products segment, such as fibre supply issues, ownership, capital expenditures, exchange rate, import duties, supply chain constraints, forest disease and fires, as well as U.S. demand and export markets in China (including the ongoing U.S. – China tariff war), Japan and other markets all create many possible scenarios. Some of the major risks and uncertainties for wood products over the forecast period include:

Upside risks:

- removal of softwood lumber tariffs. The U.S. government has imposed an average 20 per cent tariff on B.C. lumber imports. Removal of the tariff would raise revenues to B.C. producers and stimulate sawmill production,
- higher than expected in U.S. housing start levels, and
- a stronger U.S. dollar.

Downside risks:

- useable timber reductions in B.C. Large wildfires and/or accelerated beetle kill deterioration of affected timber, will reduce harvestable areas, increase harvesting costs and contribute to wood product mill closures,

- lower than expected U.S. housing start levels. The U.S. is B.C.'s largest export market; depressed levels of U.S. housing starts that cause lumber prices to decline and increase wood product mill closure risk,
- U.S. recession. A prolonged economic downturn would cause housing starts to decline and remain at low levels. This would cause lumber and panel prices to decline and increase wood product mill closure risk, and
- reduced demand from China. This could arise from a prolonged economic slowdown in China and/or the Chinese government imposing import duties on Canadian lumber.

The key reference commodity price forecasts are provided in Table 6-12 below. Shortly after receiving the lumber price forecast from our consultants, lumber prices experienced volatile and significant price increases. These price increases were unanticipated consequences related to the COVID-19 pandemic, which were occurring in the U.S. economy. These consequences resulted in increased lumber demand, decreased lumber supply, lower mortgage rates and increased availability of construction labour. Since BC's wood production is largely limited by fibre supply, the substantive price increases are not expected to have a significant upward impact on electricity demand.

Table 6-12 Wood Commodity (Lumber) Reference Price Forecast

Fiscal year	Lumber (US$/MBFM)
Actual	
F2015	$349
F2016	$277
F2017	$305
F2018	$401
F2019	$480
F2020	$359
Forecast	
F2021	$362
F2022	$446
F2023	$446
F2024	$446
F2025	$446
F2026-F2041	$487

The high and low forecasts are developed to capture some of this uncertainty. Further information on the wood high and low forecasts is provided in section 8.3.4.6.

6.5.4 Chemical

6.5.4.1 Chemical Segment Description

The chemical segment represents 21 per cent of Forestry sub-sector sales and 11 per cent of the large industrial sector. Chemical plants produce bleaching agents for the pulp and paper industry, cleaning agents or the oil and gas industry, and water purification products for municipalities. Since chemical companies use electrolysis to produce their products, electricity represents a substantial component of their operating costs.

6.5.4.2 Chemical Methodology

Consistent with the large industrial sector methodology, the chemical segment is forecast on an individual account basis. For this segment, the forecast relies on customer information provided by our Key Account Management group. The chemical forecast methodology is mainly informed via discussions with customers. Key drivers for the chemicals segment are electricity prices, demand for bleaching agents from the pulp and paper industry, and cleaning agents from the oil and gas industry. The industry also h as the ability to export its products should B.C.-based demand decline.

6.5.4.3 Chemical Forecast Results

Electricity sales in the chemical segment mirror those in the pulp and paper segment. From fiscal 2015 to fiscal 2020, chemical sales declined by about 228 GWh or 15 per cent. This decline was primarily due to savings achieved through our DSM programs as well as a plant closure in fiscal 2018.

The reference case assumes a decline in fiscal 2021 sales due to reduced demand in the pulp and paper segment as described in section (reference pulp and paper section). Beyond fiscal 2021, the reference case assumes a return to pre-pandemic sales volumes and flat growth over the long term. Table 6-13 shows the history and forecast sales to the segment after fuel switching load additions and adjustments for rate impacts and DSM.

Table 6-13 Chemical Segment Sales History and Reference Load Forecast After Adjustments

Fiscal Year	Chemical Reference Forecast (GWh)
Actual	
F2015	1,541
F2016	1,456
F2017	1,409
F2018	1,477
F2019	1,309
F2020	1,313
Forecast	
F2021	1,252
F2022	1,307
F2023	1,371
F2024	1,372
F2025	1,370
F2026	1,372
F2027	1,372
F2028	1,372
F2029	1,372
F2030	1,372
F2031	1,372
F2032	1,372
F2033	1,372
F2034	1,372
F2035	1,372
F2036	1,372
F2037	1,372
F2038	1,372
F2039	1,372
F2040	1,372
F2041	1,372
Compound Annual Growth Rates	

Fiscal Year	Chemical Reference Forecast (GWh)
5-year History CAGR (F15 - F20)	(3.2%)
5-year CAGR (F20 - F25)	0.9%
10-year CAGR (F20 - F30)	0.4%
20-year CAGR (F20 - F40)	0.2%

6.5.4.4 Chemical Uncertainties

The major risks and uncertainties for the chemical segment include the following:

Upside risks:

- higher than expected bleaching agent demand from global pulp and paper producers experiencing a sustained increase in pulp and paper prices, and
- higher than expected cleaning agent demand from oil and gas producers.

Downside risks:

- global slowdown in demand from global pulp and paper producers,
- domestic pulp and paper closures, and
- Chemical companies operating in B.C. to close and be supplied from a plant outside of BC Hydro's service area.

The high and low forecasts are developed to capture some of this uncertainty. Further information on the wood high and low forecasts is provided in section 8.3.4.4.

6.5.5 Forestry Reference Load Forecast

Table 6-14 provides the Large Industrial Forestry sub-sector sales history and Reference Load Forecast after fuel switching load additions and adjustments for rate impacts and DSM. .

Table 6-14 Forestry Sales History and Reference Load Forecast After Adjustments

Fiscal Year	Forestry Reference Forecast (GWh)
Actual	
F2015	7,959
F2016	7,390
F2017	6,723
F2018	6,954
F2019	6,519
F2020	5,893
Forecast	
F2021	4,937
F2022	4,883
F2023	4,977
F2024	4,835

Fiscal Year	Forestry Reference Forecast (GWh)
F2025	4,714
F2026	4,709
F2027	4,688
F2028	4,669
F2029	4,644
F2030	4,613
F2031	4,588
F2032	4,569
F2033	4,552
F2034	4,535
F2035	4,516
F2036	4,496
F2037	4,464
F2038	4,444
F2039	4,425
F2040	4,406
F2041	4,415
Compound Annual Growth Rates	
5-year History CAGR (F15 - F20)	(6.2%)
5-year CAGR (F20 - F25)	(4.0%)
10-year CAGR (F20 - F30)	(2.3%)
20-year CAGR (F20 - F40)	(1.4%)

Sales to all forestry sub-sector customers have declined by 2,066 GWh or26 per cent from fiscal 2015 to fiscal 2020. This decrease occurred most in pulp and paper segment where a number of mill line closures occurred during this period. For the period fiscal 2021 to fiscal 2041, the reference forecast shows a decline of 522 GWh or 10 per cent. All segments contribute to this decline. This decline is primarily due to reduced sales to the pulp and paper segment, which is driven by continued softening in demand for publication papers.

6.6 OIL AND GAS

6.6.1 Oil and Gas Sub-sector Description

Sales to the large industrial oil and gas sub-sector account for 11 per cent of the total large industrial sales. Electricity is used by oil and gas customers connected to the transmission system for various operations including refining and shipping petroleum, processing, natural gas production and liquid rich natural gas processing into various liquids. Most of the electricity is used to drive compressors for production and pipeline transportation.

The oil and gas sub-sector is categorized into two segments:

- shale gas (i.e. production/processing plants), and
- other large oil and gas operations.

The other large oil and gas operations consist of:

- natural gas straddle plants
- conventional gas processing plants,

- oil (and condensate) pipelines,
- oil refineries and oil producers,
- natural gas pipelines,
- propane terminals, and
- LNG terminals.

The above segmentation delineates aspects of natural gas processing related to the removal of various liquid-state compounds (liquids), such as propane, ethane and butane that can exist at varying levels in the raw natural gas. These processing facilities employ more energy intensive compression and refrigeration to extract the liquids; the amount of work energy being a function of the amount and type of the liquids content. Three types of processing facilities are generally defined as follows:

> Shallow-cut facilities: A gas plant next to, or within, gas field plants or gas pipelines that can extract pro pane or heavier natural gas liquids (butanes and condensate) using refrigeration technologies.
>
> Deep-cut facilities: A gas plant upstream of major gas-pipeline systems that extracts ethane and other natural gas liquids using turbo-expander or absorption technologies. It can extract more ethane than a shallow-cut gas plant, but less ethane than a straddle plant.
>
> Straddle plant: A reprocessing plant located on a gas pipeline. It extracts remaining natural gas liquids from previously processed gas.

Processing plants can fit anywhere along a spectrum of the three facility types and consequently not all of BC Hydro's customer facilities self-identify as one type or another. All of BC Hydro's existing and potential new processing customers appear to fit the shallow gas plant type and are solely dedicated to shale gas production and processing. Consequently, they are included in the shale gas segment forecast. Straddle plant plants can also have deep cut processing components and are typically located where they can process both shale gas and conventional natural gas plants. Straddle and deep cut processing plants are included in the other large oil and gas operations segment forecast.

Sales to LNG terminals are included in the other large oil and gas operations segment to maintain confidentiality on the specific nature of individual LNG projects included in the load forecast. This is consistent with our practice of not publishing customer specific history and forecasts. The remainder of this section provides a summary of the forecast results for the entire sub-sector followed by a detailed discussion of the two major segments.

The methodology in the oil and gas sub-sector is consistent with the large industrial forecast process articulated in section 6.2. However, the depth of analysis carried out for each of the segments within the oil and gas sub-sector varies depending on segment size and complexity. For example, we apply a more robust and detailed analytical approach for the large and growing shale gas segment; conversely, we adopt a less rigorous approach for the oil refineries and oil producer sub-segments, which are relatively small and static. Overall, each segment forecast is developed on an individual customer account basis, with probabilities app lied, to develop a reference load forecast.

6.6.2 Shale Gas

6.6.2.1 Shale Gas Segment Description

In fiscal 2020 electricity sales to the shale gas segment represented 65 per cent of the total oil and gas sub-sector sales and 5 per cent of large industrial sales. Electricity is mainly used to drive plant compression and processing requirements.

The shale gas segment includes the production of raw natural gas from shale or tight sedimentary formations located in the B. C. Montney shale basin. The process starts with drilling wells into the formations using hydraulic fracturing techniques to access the gas. Since this technique differs from the older conventional process, gas produced in this manner is also called unconventional g as. Gas from these wells is under high pressure and is connected to gathering pipes which bring the gas to gas plants. These plants (increasingly being served by BC Hydro) perform light processing of the gas including refrigeration if needed to recover gas liquids (propane, butane and condensates). While the work energy components supplied by electricity vary from customer to customer, they generally encompass the following field compression and processing activities:

- booster stations,
- water recycling operations,
- gas processing plant (ranging from the low electrical intensity dry gas plants, to higher intensity shallow cut gas plants),
- additional compression requirements as pipeline pressure increases over time,
- higher refrigeration requirements needed for plants processing higher gas liquids ratios (i.e., shallow cut processing), and
- additional compression requirements as wells age over time.

In general, work energy intensity within the shale gas segment has been increasing as new projects focus on more liquids-rich areas and the associated shallow cut gas processing plants require relatively higher compression work energy. While BC Hydro reflects this increasing work energy trend as part the forecast methodology described in section 6.5.2.2, the primary basis for developing new customer forecasts is project-specific load information directly provided by the proponents.

Other work energy associated with activities such hydraulic fracturing can also be electrically supplied by BC Hydro, while there may be future electrification potential associated with these activities as part of future climate actions, they are not included in this load forecast. This assumption is based on the fact that BC Hydro has not received material service requests to supply fracking load. In any event, fracking load makes up a small portion of the overall work energy requirements.

6.6.2.2 Shale Gas Methodology

Consistent with the large industrial sector methodology, the shale gas segment is forecast on an individual customer account basis. However, the shale gas segment is the fastest growing within our large industrial sector and given the complex nature of the industry requires more detailed analysis relative to other industrial sectors. A comprehensive analytical framework is used to directl y link BC Hydro's internal assessment of customer accounts and new service requests (i.e., bottom up assessment) with supply and demand outlooks for natural gas, natural gas liquids and oil natural gas production forecasts developed by a third party expert assessment as well as from market intelligence information provided by various subscription services and publicly available sources. The longer-term outlook also relied on the third-party expert assessment that was developed for BC Hydro's (i.e., top down assessment).

In developing this forecast, the bottom-up assessment is a list of probability weighted customer load requests. These requests are categorized into the six sub-regional load forecasts in the Montney gas basin. The top-down assessment is a Montney gas production forecast that is converted into an electrical load forecast (organized into the same six sub-regions).

The bottom-up and top-down forecasts are iterated until they converge by adjusting the following parameters:

Bottom-up Forecast

The bottom-up forecast is based on customer specific information and analysis and is the basis for the shale gas segment forecast. The bottom-up forecast is developed by compiling the current and expected customer load requests to arrive at load forecasts for each of the six sub regions. During this process each customer request is evaluated, shaped and discounted based on information from various internal and external sources as described above. The outcome is a weighted probability assessment of energy requirements and the dates when that energy is forecasted to be supplied by BC Hydro for new start-ups or electrification of existing plants. Most of the work energy used to supply natural gas production and processing can be supplied electrically or self-supplied using diesel or extracted hydrocarbons including natural gas. Customers are also able to self-supply their electricity requirements or be electrically supplied by BC Hydro. Consequently, customer requests include two discrete probability assessments: (1) the likelihood the project will be developed, and (2) the likelihood the project will be electrically supplied by BC Hydro.

Top-Down Forecast

The top-down forecast is a macro forecast that is primarily used as a guide to check and confirm the reasonableness of the bottom up forecast. The top down forecast is derived by creating and the multiplying three data sets, as follows:

Top down forecast (MW) = gas production (MMcf/day) x energy intensity (MW/MMcf) x electricity service per cent (%)

Energy intensity and electricity service per cent are direct inputs into the top down forecast, whereas gas production is derived by varying well profile inputs and drilling activity inputs, gas demand parameters (e.g., LNG export, export to North America and gas liquids demand for oil sands production), gas supply parameters (e.g., well production characteristics and drilling activity), and finally electrification parameters (e.g., regional service electrification characteristics and electrical load electricity intensities).

The major parameters listed above are those that can be adjusted during the iterative process as necessary. In addition, there are a number of other components of the top down model that serve to inform the test for defensibility and evaluate adjustment reasonability. These include:

- A component that ensures that forecast gas production in each of the six sub regions does not exceed gas in place estimates;
- Pipeline related analysis for BC gas exports to North American markets;
- Well production costs within the BC Montney compared with the rest of North America;
- BC Montney gas liquids production forecasts;
- Natural gas and gas liquids price forecasts; and
- Oil sands development and condensate demand analysis.

Professional judgment is used to determine if any adjustments are required to the bottom up and/or top down forecasts of the six sub regions, so that the forecasts converge, while ensuring that each forecast is supported by detailed customer requested information and independent macroeconomic analysis.

For instance, if the bottom-up forecast for one of the six sub-regions is much higher than what is in the top-down forecast, we would check the bottom-up assumptions for defensibility. If it is felt that the probability weightings in the bottom-up were too high, then the iteration would be to lower them until the bottom-up and top-down forecasts align.

6.6.2.3 Shale Gas Forecast Results

From fiscal 2015 to fiscal 2020 sales to the shale gas segment increased by 1,398 GWh, a tenfold increase, due to the exponential growth of shale gas extraction in the BC Montney region and the close proximity of these wells to BC Hydro transmission assets, making it economic to electrify a portion of the shale gas growth. Table 6-15 shows the history and forecast sales after fuel switching load additions and adjustments for rate impacts and DSM. The allocation of DSM between segments is an approximation based on the total DSM for the oil and gas and LNG sub-sectors.

Table 6-15 Shale Gas Segment Sales History and Reference Load Forecast After Adjustments

Fiscal Year	Shale Gas Reference Forecast (GWh)
Actual	
F2015	142
F2016	440
F2017	555
F2018	710
F2019	1,416
F2020	1,540
Forecast	
F2021	1,444
F2022	1,552
F2023	1,966
F2024	2,246
F2025	2,538
F2026	2,748
F2027	2,901
F2028	2,965
F2029	3,025
F2030	3,091
F2031	3,126
F2032	3,127
F2033	3,128
F2034	3,128
F2035	3,127
F2036	3,127
F2037	3,127
F2038	3,126
F2039	3,126
F2040	3,126
F2041	3,130
Compound Annual Growth Rates	
5-year History CAGR (F15 - F20)	61.1%
5-year CAGR (F20 - F25)	10.5%
10-year CAGR (F20 - F30)	7.2%
20-year CAGR (F20 - F40)	3.6%

For future electricity sales, the reference case assumes the COVID-19 pandemic has only a relatively modest impact on B.C. shale gas production through fiscal 2021 with the electricity sales forecast to decline by approximately 100 GWh or six per cent relative to fiscal 2020 actual sales. This modest impact is based on the assessment that natural gas and natural gas liquids prices are assumed to remain at sufficient levels to support BC production. Similarly, Alberta oil sands production (a major natural gas and natural gas liquids consumer), is assumed to be largely unaffected by lower oil prices caused by reduced demand caused by the COVID-pandemic and short-lived price war between Russia and Saudi Arabia.

For the fiscal 2021 to fiscal 2041 period the reference forecast assumes sales increase by 1,686 GWh or 17 per cent. This increase is primarily driven from projects that recently started commercial operations or are currently under construction and are expected to come into service by fiscal 2021.

The shale gas reference forecast includes load associated with LCE Customer Project 1 and LCE Customer Project 2, which are mentioned in Appendix N to BC Hydro's Fiscal 2022 Revenue Requirements Application.

Broadly speaking, our analysis leads us to believe that much of the increase in global natural gas supply will occur in North America. In this context, B.C.'s Montney shale basin is considered to be a competitive low-cost gas supplier as the basin's size, productivity and mix of liquids enables it to compete with other sources of gas supply. The consultant reported that the basin's competitiveness is not considered to be dependent on access to LNG markets and forecasts continued natural gas production growth in B.C. with an increasing share of the Western Canadian gas supply market.

6.6.2.4 Shale Gas Uncertainties

While additional load growth potential is relatively low in the short term, there is considerable, albeit uncertain long-term potential. The potential downside is considered low for both the near and long term. Upside and downside risks include the following:

Upside risks include:

- future North American LNG development (B.C., U.S. west coast and U.S. gulf coast) increasing demand for B.C. natural gas,
- continued expansion of Alberta's oil sands and associated demand for gas liquids,
- continued displacement of net U.S. gas liquids imports to Alberta with B.C. gas liquids,
- higher than expected natural gas, liquids, and oil prices, and
- higher than expected electrification percentages of new facilities.

Downside risks include:

- condensate production in Alberta (large basin in Western central Alberta has a logistical advantage to oil sands producers than B.C. producers),
- Alberta importation of U.S. condensate for heavy oil production (threatens B.C. producer growth),
- increased gas liquids production in Alberta (closer to petrochemical plants in Alberta),
- lower than expected natural gas prices caused by increased natural gas production in other North American production regions,
- delay of LNG terminal operational dates, and
- lower the expected electrification percentages of new facilities

The high and low forecasts are developed to capture some of this uncertainty. Further information on the oil and gas high and low forecasts is provided in section 8.3.4.8.

6.6.3 Other Large Oil and Gas Operations

6.6.3.1 Other Large Oil and Gas Operations Segment Description

Based on fiscal 2020 actuals, sales to the other large oil and gas operations segment represents 35 per cent of all the sales to the oil and gas sub-sector. This segment consists of the following facility types:

- Natural gas straddle plants
- Conventional gas processing plants,
- Oil (and condensate) pipelines,
- Oil refineries and oil producers,

- Natural gas pipelines,
- Propane terminals, and
- LNG terminals.

In fiscal 2020 natural gas straddle plants comprised 10 per cent of BC Hydro's sales to the oil and gas sub-sector. These customers extract remaining natural gas liquids from previously processed gas. Conventional gas processing plants comprise one per cent of BC Hydro's sales to the oil and gas sub-sector. These customers use conventional means to recover gas, perform gas liquids extraction (ethane, propane, butane and pentane) and extract acid gases. Historically, the processors have served conventional gas producers. However, conventional gas production in B.C. has been declining over the past 10 years and as conventionally gas production declines, processing plants are increasingly being supplied by shale gas producers.

Oil pipelines constitute 9 per cent of BC Hydro's sales to the oil and gas sub-sector. These customers operate pipelines which serve to transport crude oil and petroleum products. Electricity is primarily used in pumping stations with power sales being correlated to the volume of liquids shipped. Future growth opportunities for this industry are due to B.C.'s proximity to Asian oil markets where oil demand is increasing and U.S. west coast oil refineries.

Oil refineries and oil producers currently make up 10 per cent of BC Hydro's sales to the oil and gas sub-sector. These customers include tank farms, oil refineries (which also produce gasoline and jet fuel) and oil producers. Electricity sales are related to B.C.'s oil pipeline shipments and to a lesser degree oil prices.

Natural gas pipelines comprise less than one per cent of BC Hydro's sales in the oil and gas sub-sector. These customers ship natural gas via pipeline. Natural gas pipelines use gas compressors instead of electrically driven compressor to power booster stations.

Propane terminals are an emerging B.C. industry with two new terminals currently under construction. When construction is complete, these customers will receive the propane by rail, store it in tanks and then pump the propane from the terminals onto ships for export. Our industry consultant produced a B.C. propane terminal supply analysis, which was used to inform the propane terminal forecast. Electricity will be used for pumps and compressors with future sales related to world propane prices, Asian demand and B.C. terminal propane. Propane supply is expected to be sourced from the B.C. Montney and the Alberta Duverney shale gas basins.

LNG is natural gas that has been cooled to a liquid state, at about negative160 degrees Celsius, for shipping and storage. The volume of natural gas in its liquid state is hundreds of times smaller than its volume in its gaseous state. This process allows the transportation of natural gas to places pipelines do not reach. LNG is shipped in special tankers between export terminals, where natural gas is liquefied, and import terminals, where LNG is returned to its gaseous state (degasified).

British Columbia has the advantage of shorter shipping distances to Asia relative to other LNG suppliers and substantial natural gas reserves including the Montney, Horn River and Liard formations. After an initial boom in global LNG project development, global LNG investment decreased following a drop in LNG prices in 2014. Investment appetite was further diminished by fears of an extended supply surplus. British Columbia's LNG sector followed similar a pattern with the more than 20 LNG project proposals, followed by a number of project cancellations. China and India led the recovery in demand for LNG following the outbreak of the pandemic with both countries increasing their LNG imports by over 10 per cent during 2020. LNG markets are still oversupplied in the short-run, but a balanced position is expected by mid-2020s driven by a combination of demand growth and a fall off in new supply coming on-stream. China's announcement of a target to become carbon neutral by 2060 is expected to support long term growth in LNG demand.

Over the past few years, BC Hydro and the provincial government have been working closely with LNG proponents on options for meeting energy needs of LNG plants with power from the BC Hydro system. LNG-related electricity demand falls into two general categories: compression and non-compression. The compression energy is about 85 per cent of the total plant's energy needs. The remaining (non-compression) energy requirement is from plant pumps, motors, other equipment, heating and lighting. Compression energy is typically supplied with direct-drive natural gas turbines, although this can also be accomplished with electric drives.

In October 2018, LNG Canada announced a positive final investment decision to proceed with its project located in Kitimat, B.C. LNG Canada is the single largest private sector investment project in Canadian history. The first phase of the p roject includes a $6.2-billion natural gas pipeline through northern British Columbia and an $18-billion liquefaction facility in Kitimat, B.C.

In addition to LNG Canada, FortisBC's Tilbury LNG plant is operating and taking electricity service from BC Hydro and a number of other B.C. based LNG projects are continuing to advance.

6.6.3.2 Other Large Oil and Gas Operations Methodology

Consistent with the large industrial sector methodology, the other large oil and gas sector is forecast on an individual customer account basis. Within this customer-based forecasting process, various calculation techniques are used to arrive at the customer's energy and peak forecasts.

The primary method is the product of expected peak demand, load factor and probability. The load factor is a measure of the utilization rate, or efficiency of electrical energy usage. Generally, the underlying drivers of the forecast are the customer's requested load, estimated operational hours, historical load patterns and operational probabilities. In case of existing customers, historical consumption information is used as starting reference point updated with newest information (such as facility expansion or contraction plans). The probability weightings are informed by considerations such as the project's economics, availability of financing, regulatory progress and BC Hydro interconnection status. A facility's economics is analyzed in the context of the market outlooks informed by external an d internal information. For the current forecast, BC Hydro relies on the following subscription services:

- New Energy Finance,
- Wood Mackenzie North America Gas Service,
- IHS Connect, and
- RBN Energy's paid for information services on North American: oil, natural gas liquids, natural gas and the Permian basin.

Additional information was obtained through an oil and gas consultant. This information included:

- B.C. conventional gas basin forecasts,
- oil price forecasts and Alberta oil supply forecasts,
- reporting on natural gas pipeline development, and
- analysis on B.C. propane terminal propane supply.

LNG customers are included in the large oil and gas segment to protect the confidentiality of our assessment of LNG projects. In developing the LNG forecasts, we continue to include in the forecast only those LNG projects that are already operational or have requested service. Probably assessments of individual LNG projects were developed based on:

- input from Key Account Management and Load Interconnections business units, and
- third party expert assessments of the global LNG market, relative competitiveness of B.C. LNG, and specific B.C. projects.

To do this we rely on the Wood Mackenzie LNG, as well as information from publicly available sources such as McKinsey's Energy Insight, National Energy Board, International Energy Agency, Canadian Energy Research Institute and Bloomberg.

6.6.3.3 Other Large Oil and Gas Operations Forecast Results

Table 6-16 below shows the history and forecast sales after fuel switching load additions and adjustments for rate impacts and DSM. From fiscal 2015 to fiscal 2020 sales in the other large oil and gas operations segment have decreased by 210 GWh or 20 per cent. The decline is primarily due to lower sales to conventional gas producers and processors. These customers have been impacted by the downward trend in natural gas prices that have occurred during this period.

Table 6-16 Other Large Oil and Gas Operations Segment Sales History and Reference Load Forecast After Adjustments

Fiscal Year	Other Large Oil and Gas Reference Forecast (GWh)
Actual	
F2015	973
F2016	836
F2017	818
F2018	797
F2019	831
F2020	763
Forecast	
F2021	788
F2022	844
F2023	992
F2024	1,718
F2025	2,504
F2026	3,218
F2027	3,362
F2028	3,581
F2029	3,577
F2030	3,574
F2031	3,570
F2032	3,567
F2033	3,563
F2034	3,560
F2035	3,556
F2036	3,551
F2037	3,547
F2038	3,543
F2039	3,538
F2040	3,534
F2041	3,532
Compound Annual Growth Rates	
5-year History CAGR (F15 - F20)	(4.7%)
5-year CAGR (F20 - F25)	26.8%
10-year CAGR (F20 - F30)	16.7%
20-year CAGR (F20 - F40)	8.0%

Sales are expected to remain fairly flat until fiscal 2022. From fiscal 2022 to fiscal 2026, sales increase by 2,388 GWh or 280 per cent. This growth is attributed to sales to LNG terminals, pipelines, and straddle plants.

While assumptions for specific LNG projects are confidential, the load forecast reflects the following publicly available information:

- FortisBC Tilbury is in operation and we included forecast sales to this LNG facility;
- LNG Canada phase 1 is currently under construction;
- Woodfibre LNG's decision to proceed with the project has not been yet announced. The forecast reflected a probability-weighted assessment;

- Kitimat LNG load reflected a probability-weighted assessment;
- Other activities contributing to oil and gas sub-sector load growth include new pipelines and propane terminals; and
- Other LNG projects are considered within the load forecast uncertainty bands. .

The commodity price assumptions used to complete the top-down assessment for the oil and gas sub-sector are provided in Table 6-17 below.

Table 6-17 – Oil and Gas Commodity Reference Price Forecasts

Fiscal year	Henry Hub (US$/MMBtu)	AECO CA$/MMbtu	WTI Cushing Oklahoma $US/Bbl
Actual			
F2015	$ 4.92	$ 102	$ 112
F2016	$ 2.90	$ 52	$ 66
F2017	$ 2.30	$ 46	$ 59
F2018	$ 2.28	$ 53	$ 70
F2019	$ 1.57	$ 66	$ 81
F2020	$ 1.84	$ 58	$ 73
Forecast			
F2021	$ 2.12	$ 39	$ 48
F2022	$ 2.39	$ 44	$ 55
F2023	$ 2.64	$ 51	$ 64
F2024	$ 2.64	$ 54	$ 68
F2025	$ 2.64	$ 54	$ 68
F2026-F2041	$ 2.64	$ 54	$ 68

6.6.3.4 Other Large Oil and Gas Operations Uncertainties

The various industries making up this segment face somewhat different risks and uncertainties. This is because the products and markets within the sub-segments are different. The description for the major risks is provided below. LNG-related risks are described separately.

The risks associated with the large oil and gas operations, excluding LNG terminals, collectively tend to weigh more on the downsi de than the high side in terms of potential impacts to BC Hydro sales.

The upside risks include:

- Higher than expected Asian demand for propane would incent propane terminal expansions in B.C.,
- Higher than expected oil sands transport venues and expanded fossil fuel processing capacity in Alberta would stimulate the conventional gas processing plants to recover more natural gas liquids,
- Higher than expected oil prices would increase B.C. oil refinery oil production and oil pipeline activity, and
- Minimal fossil fuel related construction delays would lower perceived risk and incent further development.

The downside risks include:

- Oversupply of fossil fuels in global, Alberta and U.S. markets and lower than expected prices to B.C. producers. This will cause B.C. oil refineries, oil producers and conventional gas processing plants to reduce production, defer new projects, and shut plants,
- New gas liquids pipeline from the U.S. into Alberta. This will reduce profit margins for B.C. producers and reduce convention al gas processing plants activity, and

- Longer than expected infrastructure construction delays, including due to the COVID-19 pandemic or project cancellations.
- Increased climate action policies that decrease global and domestic demand for fossil fuels

For LNG terminals, the major risks are identified below. Notwithstanding LNG Canada's positive investment decision, LNG development in B.C. remains an emerging industry with uncertain growth potential. The risk profile for this industry is asymmetrical in that the potential for higher load growth relative to what is reflected in the load forecast is greater than the potential for lower load. Various risks that have can have either positive or negative impacts on B.C. LNG development include:

- Federal/provincial policies that support or restrict domestic LNG development,
- Large upturns/downturns in the energy markets leading to unexpected supply surpluses or deficits,
- Legislation that supports or restricts nuclear power in Japan and coal generation in China,
- Climate action policies that increase or decrease global demand for natural gas,
- Competition with U.S. based LNG and other major LNG export countries, and
- Indigenous community support for or against LNG and related pipeline and natural gas development.

6.6.4 Oil and Gas (Including LNG) Reference Load Forecast

Table 6-18 shows the Large Industrial Oil and Gas (including LNG) sub-sector sales history and Reference Load Forecast after adjustments for rate impacts and DSM. From fiscal 2015 to fiscal 2020, sales to the large industrial oil and gas sub-sector have increased by 1,187 GWh or 106 per cent. This is based on the combined total of sales to shale and other large oil and gas operations customers. This increase is primarily due to growth in the shale gas segment.

Table 6-18 - Oil and Gas and LNG Reference Load Forecast After Adjustments

Fiscal Year	Reference Forecast (GWh)
Actual	
F2015	1,116
F2016	1,276
F2017	1,373
F2018	1,507
F2019	2,247
F2020	2,303
Forecast	
F2021	2,232
F2022	2,395
F2023	2,958
F2024	3,964
F2025	5,042
F2026	5,966
F2027	6,263
F2028	6,546
F2029	6,602
F2030	6,664
F2031	6,696
F2032	6,694
F2033	6,692
F2034	6,688
F2035	6,683
F2036	6,678
F2037	6,674

Fiscal Year	Reference Forecast (GWh)
F2038	6,669
F2039	6,664
F2040	6,660
F2041	6,662
Compound Annual Growth Rates	
5-year History CAGR (F15 - F20)	15.6%
5-year CAGR (F20 - F25)	17.0%
10-year CAGR (F20 - F30)	11.2%
20-year CAGR (F20 - F40)	5.5%

From fiscal 2020 to fiscal 2025, the expected (reference) sales are forecast to grow by 2,739 GWh or 119 per cent. This growth is driven by new shale gas production plants that: have switched to BC Hydro service, have started operations and are ramping up production or are under construction. The reference forecast also assumes increased sales to the other large oil and gas operations segment, primarily driven by LNG terminals.

Although the oil and gas sub-sector is comprised of customers all related to the fossil fuel industry, the major risks and uncertainties for each are generally different. This is because the products and markets within the segments and sub-segments are different. Nevertheless, the risk profile for this segment is asymmetrical in that the potential for higher load growth relative to what is reflected in the load forecast is greater than the potential for lower load. This asymmetry is due to LNG terminals and pipelines, as well as potential for increased electrification in natural gas production and processing associated with the CleanBC Plan.

The high and low forecasts are developed to capture some of this uncertainty. Further information on the oil and gas high and low forecasts is provided in section 8.2.4.

6.7 OTHER LARGE INDUSTRIAL

6.7.1 Other Large Industrial Sub-sector Description

The other large industrial sub-sector is comprised of a range of customers from universities, ports, terminals and wire manufacturers to cement companies and water pumping stations. The other large industrial sub-sector also includes cryptocurrency and data centres loads that we expect to be connected at transmission voltages.

6.7.2 Other Large Industrial Methodology

Customers in the other category are forecast on an individual customer account basis consistent with the large industrial sector methodology. However, this sub-sector forecast is not directly informed by specific commodity price or market outlooks due to the sub-sector's diversity. The forecast is primarily based on customer information provided via our Key Accounts Management and Load Interconnection business units.

6.7.3 Other Large Industrial Reference Load Forecast

Table 6-19 provides the Other Large Industrial sub-sector sales history and Reference Load Forecast, after adjustments.. Over the six years ending fiscal 2020, sales to the Other Large Industrial sub-sector decreased slightly by 37 GWh. A small increase from several customers expanding activities has been more than offset by closures such as the Lafarge cement plant in Kamloops and Esco foundry in Port Coquitlam due to market conditions.

Table 6-19 – Other Large Industrial Sales History and Reference Load Forecast After Adjustments

Fiscal Year	Other Large Industrial Reference Forecast (GWh)
Actual	
F2015	1,173
F2016	1,149
F2017	1,126
F2018	1,171
F2019	1,136
F2020	1,144
Forecast	
F2021	1,072
F2022	1,165
F2023	1,215
F2024	1,220
F2025	1,154
F2026	1,100
F2027	1,106
F2028	1,103
F2029	1,098
F2030	1,094
F2031	1,104
F2032	1,109
F2033	1,118
F2034	1,122
F2035	1,130
F2036	1,135
F2037	1,143
F2038	1,148
F2039	1,157
F2040	1,163
F2041	1,175
Compound Annual Growth Rates	
5-year History CAGR (F15 - F20)	(0.5%)
5-year CAGR (F20 - F25)	0.2%
10-year CAGR (F20 - F30)	(0.4%)
20-year CAGR (F20 - F40)	0.1%

The COVID-19 pandemic is anticipated to have a negative effect on the other sub-sector reference forecast in fiscal 2021 with a reduction in load from large customers such as Vancouver International Airport or UBC. Load additions for cryptocurrency and data centres in the next two years coupled with the slow return to normal activities for most customers will result in the load returning to pre-pandemic level by fiscal 2022. The reference forecast grows approximately 100 GWh over the entire period primarily due to upgrades and expansions from existing customers.

6.7.4 Other Large Industrial Uncertainties

The major uncertainties around the other large industrial loads include:

- the effect of COVID-19 on large customers such as universities, airports and shipping terminals,
- uncertainty regarding cryptocurrency operations and data centres,
- economic growth and construction activity, which in turn affects the demand for cement and other industrial products,
- sectorial shifts in the B.C. economy (e.g., shift from manufacturing to services, emerging sectors such as data centres or cryptocurrency),
- slowdown or increase in shipping,
- Expansions to large customers such as Vancouver International Airport or UBC, and
- Electrification of shipping/transportation industry.

The high and low forecasts are developed to capture some of this uncertainty. Further information on the other sub-sector high and low forecasts is provided in section 8.4.4.9.

7.0 Electric Vehicle Forecast

7.1 ELECTRIC VEHICLE FORECAST DESCRIPTION

BC Hydro develops an EV load forecast to estimate electricity sales across our system due to growth in the total number of light duty electric vehicles in B.C. The EV forecast is split amongst the residential sector and commercial sectors based on Insurance Corporation of British Columbia (ICBC) data on the number of light duty electric vehicles that are for personal and business use. As a result, 85 per cent of the total EV load forecast is allotted to the residential sector and 15 per cent is allotted to the commercial sector.

We are developing and implementing a new Electric Vehicle model, which expands the forecasting capability to also include medium and heavy duty vehicles. Results will be incorporated into future load forecasts when the model is available and testing of the model is complete.

7.2 ELECTRIC VEHICLE METHODOLOGY

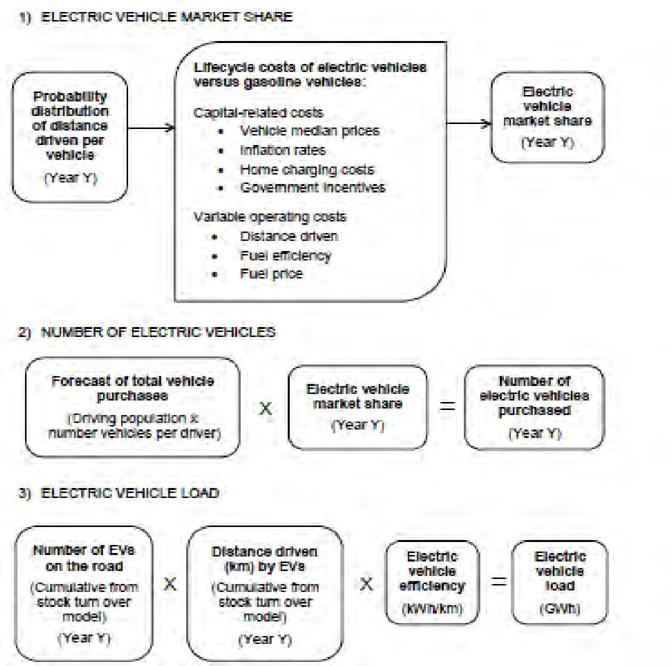
BC Hydro's EV load forecast is based on our in-house EV stock turn over model (EV model). The EV model combines both types of EVs (battery plug-in vehicles and plug-in hybrid vehicles).

7.2.1 Non-Luxury EV Forecast Model

The EV model develops a forecast of the total stock of EVs. Our EV model distinguishes between luxury EVs[9] and non-luxury EVs. A trend analysis is used to develop a forecast for the number of luxury EVs. The load forecast for luxury EVs is added to the load forecast for the non-luxury EVs which is developed by the EV model discussed below. Figure 7-1 below illustrates the key inputs and calculations of our non-luxury EV model.

[9] Luxury EVs are not eligible for government incentives as such these are modelled and forecasted separately.

Figure 7-1 Electric vehicle model



7.2.1.1 Computation of annual EV market share

The EV model starts with a forecast of the annual EV market share (ratio of the annual number of EVs to the annual number of vehicles). The key drivers for determining the market share include: (i) a distribution of the driving distance for all types of vehicles, and (ii) the costs of EVs relative to gasoline vehicles which are broken down to fixed and variable costs. The fixed cost reflects the capital related costs of vehicles, which include median sales prices (for both EVs and gasoline vehicles), announced government incentives, and home charging costs for EVs. Variable costs reflect operating costs which are determined by the annual distance driven, fuel efficiencies, and electricity rates versus gasoline prices.

The EV model randomly selects an annual distance driven from an overall probability distribution of annual distance driven per vehicle (fitted to historical data). Next, the model computes the total cost as per the randomly selected annual distance driven and compares it to a break even cost as well the range constraint, which is the maximum annual distance driven or maximum range (in kilometres) for EVs. The break-even cost is the cost at which the model estimates an indifference to gasoline vehicles and EVs. The comparison analysis results in the initial annual EV market share.

The initial market share is adjusted over the near term of the forecast period to reflect an assumed gradual development of adoption of EVs. We assume EV adoption will grow gradually because of a number of factors such as gradual increases in consumer preference, vehicle range, infrastructure improvements, and EV model availability.

7.2.1.2 Computation of the Total Number of Electric Vehicles

The forecast of the annual total number of EVs is determined by the product of the EV market share and the total vehicle purchase forecast. The total vehicle purchase forecast is determined by the product of the driving population forecast and an estimate of the number of vehicles per driver. The stock turn over portion of the EV model keeps track of the vehicle life expectancy and the annual distance driven of EVs. As such, the year over year change in the total number of EVs as shown in Table 9-1 below does not equal to the annual number of vehicles purchased.

7.2.1.3 Computation of Electric Vehicle Load

Part three of Figure 9-1 illustrates the annual EV load in GWh resulting from a product of three variables which include the total number of EVs, the annual distance driven per EV, and the average efficiency of EVs.

7.2.2 December 2020 EV Forecast Model Assumptions

The December 2020 EV energy Load Forecast reflects the CleanBC Plan's approach to light-duty EVs; specifically, to incorporate the Zero-Emission Vehicles Act (ZEV Act), which was enacted on May 30, 2019. The ZEV Act stipulates percentage targets for new light-duty vehicle sales in B.C. that must have zero emissions, as follows: 10 per cent of sales by 2025, 30 per cent of sales by 2030, and 100 per cent of sales by 2040.

Accordingly, the low-EV forecast in the December 2020 Load Forecast uses these requirements as a floor for EV adoption. In contrast, the high-EV forecast assumes the natural uptake of EVs will be higher than the minimum requirements set out in the ZEV Act, as the purchase costs decline, and consumers' preferences change over time. BC Hydro developed its reference EV forecast by taking the average of the high and low EV forecasts.

7.3 EV FORECAST RESULTS

Table 7-1 below shows the EV stock for the low, reference and high scenarios. The EV stock share is a ratio of the total number of EVs to all vehicles.

Table 7-1 – EV Stock Forecast

Fiscal year	Low Forecast (number of vehicles)	Reference Forecast (number of vehicles)	High Forecast (number of vehicles)
Actual			
F2015	2,122	2,122	2,122
F2016	3,195	3,195	3,195
F2017	6,473	6,473	6,473
F2018	11,434	11,434	11,434
F2019	22,254	22,254	22,254
F2020	39,933	39,933	39,933
Forecast			
F2021	56,029	58,025	60,021
F2022	72,644	83,808	94,972
F2023	90,865	116,292	141,720
F2024	110,723	155,517	200,312
F2025	132,065	200,473	268,881
F2026	155,667	251,374	347,082
F2027	183,295	314,246	445,197
F2028	212,229	383,980	555,731
F2029	242,205	460,327	678,449
F2030	274,145	543,548	812,951
F2031	312,053	635,394	958,736
F2032	357,682	736,381	1,115,080
F2033	410,617	845,910	1,281,204
F2034	470,483	963,383	1,456,283
F2035	536,904	1,089,943	1,642,981
F2036	609,517	1,226,755	1,843,993
F2037	687,932	1,362,612	2,037,292
F2038	771,720	1,496,824	2,221,929
F2039	860,406	1,628,757	2,397,108

Fiscal year	Low Forecast (number of vehicles)	Reference Forecast (number of vehicles)	High Forecast (number of vehicles)
F2040	953,452	1,757,812	2,562,172
F2041	1,048,008	1,882,330	2,716,651
Compound Annual Growth Rates			
5-year History CAGR (F15 - F20)	80%	80%	80%
5-year CAGR (F20 -F25)	27%	38%	46%
10-year CAGR (F20 - F30)	21%	30%	35%
20-year CAGR (F20 - F40)	17%	21%	23%

Table 7-2 shows the low, reference and high EV scenarios before rate impacts for each of the residential and commercial sectors.

Table 7-2 – EV Load Forecast

	Low Forecast			Reference Forecast			High Forecast		
Fiscal year	Residential (GWh)	Commercial (GWh)	Total (GWh)	Residential (GWh)	Commercial (GWh)	Total (GWh)	Residential (GWh)	Commercial (GWh)	Total (GWh)
F2021	132	23	156	135	24	159	138	24	162
F2022	212	37	250	229	40	269	246	43	289
F2023	268	47	315	309	54	363	350	62	411
F2024	328	58	386	400	71	471	473	83	556
F2025	392	69	462	504	89	592	615	108	723
F2026	463	82	545	624	110	734	784	138	923
F2027	545	96	641	776	137	913	1,007	178	1,185
F2028	631	111	742	945	167	1,112	1,259	222	1,481
F2029	720	127	847	1,129	199	1,328	1,538	271	1,809
F2030	808	143	951	1,326	234	1,559	1,843	325	2,168
F2031	893	158	1,050	1,534	271	1,804	2,175	384	2,559
F2032	992	175	1,167	1,761	311	2,072	2,530	446	2,976
F2033	1,103	195	1,298	2,005	354	2,358	2,906	513	3,419
F2034	1,228	217	1,444	2,266	400	2,666	3,304	583	3,888
F2035	1,359	240	1,598	2,543	449	2,992	3,728	658	4,386
F2036	1,498	264	1,763	2,841	501	3,343	4,184	738	4,923
F2037	1,647	291	1,937	3,134	553	3,688	4,622	816	5,438
F2038	1,807	319	2,126	3,424	604	4,028	5,041	890	5,930
F2039	1,982	350	2,331	3,710	655	4,365	5,438	960	6,398
F2040	2,173	383	2,556	3,993	705	4,698	5,814	1,026	6,839
F2041	2,378	420	2,797	4,270	754	5,024	6,163	1,088	7,251

7.4 EV FORECAST UNCERTAINTIES

EV Load Forecast uncertainties relate to EV model inputs, such as fuel prices and capital cost, as well as uncertainties associated with the model itself. There are also a number of difficult to quantify uncertainty factors, which create risks the EV load will be higher or lower than forecast. Examples include:

- Vehicle ownership rates regardless of the drivetrain (e.g. vehicle ownership as a percentage of the total population may be higher/lower relative to historical trends),
- Impact of autonomous vehicles and car sharing on the overall vehicle sales,
- Impact of better public transportation,
- Automakers' long-term plan for introducing new EV models to convert their vehicle lineup to EVs, and
- Long-term impact of the COVID-19 pandemic if business allow employees to continue to work from home.

8.0 High and Low Uncertainty Bands

8.1 UNCERTAINTY BAND INTRODUCTION

BC Hydro's load forecasting methodology continues to incorporate high and low uncertainty bands to account for source of forecasting uncertainty. They for part of the broader suite of forecasts that encompass the December 2020 Load Forecast.

Load forecasts are sensitive to many input variables that drive the forecasts, which have varying degrees of uncertainty associated with them. These uncertainties influence the risk that future loads will be lower or higher than forecast. They can exist at a customer specific level, sector wide level or economy wide level.

There are also uncertainties associated with the various models used to develop load forecasts, such as the accuracy of using statistically determined relationships between drivers and load to forecast loads at a point in time where the nature of those relationships may be changing.

Finally, uncertainties exist when there is limited history from which to develop future projections. These uncertainties exist where there are new or emerging sectors, such as EVs, LNG, cannabis and cryptocurrency/data centres. This type of uncertainty also occurs where new public policies such as those related to climate change mitigation actions (climate action) that drive market transformation towards increased electricity use.

The December 2020 Load Forecast includes low and high uncertainty bands as well as an accelerated electrification scenario that are intended to capture the following risks and uncertainties:

- Economic risk, particularly as it relates to how global, national and provincial economies are impacted by, and recover from, the COVID-19 pandemic, and potential long-term structural changes that might result;
- The future of emerging sectors of cryptocurrency/data centres and cannabis within British Columbia;
- Customer and project specific uncertainties in each of the large industrial sub-sectors, and;
- The possibility of a large and rapid increase in low carbon electrification through climate action policies. This could impact the oil and gas and mining sub-sectors, light duty EV sales and the entire transportation sector and the built environment..

While many uncertainties and risks are accounted for in the high and low bands and Accelerated Electrification Scenario, it is normal that they will not capture every possible outcome. Some uncertainties and risks remain unaccounted for. Examples include:

- Colder or warmer than anticipated temperatures which could lead to higher or lower sales;

- Specific customer start-ups or closures not captured in the industrial low and high forecasts; and
- Housing stock growth that maybe higher or lower than Conference Board forecasts as a result of various factors impacting the housing market such as taxes, interest rates and affordable housing policies.

Additional detail on the methodology and results is described in the following sections.

8.2 UNCERTAINTY BAND METHODOLOGY AND RESULTS

BC Hydro regularly reviews and improves upon its load forecast methodology and adapts its forecast approach, where warranted, to meet changing needs. The load forecast uncertainty band methodology has been evolving in recent years towards increased used of more discrete low and high forecast assumptions rather than reliance on a Monte Carlo simulation model approach. The COVID-19 pandemic poses potential downside risk to the forecast while electrification poses potential upside. In order to capture the wide range of possibilities posed by these unprecedented phenomenons, discrete scenarios were developed to inform the high and low load forecasts for the December 2020 Load Forecast.

For the December 2020 Load Forecast, the high uncertainty band is the sum of the following discrete scenarios:

- High EV forecast;
- High large industrial forecast developed on an account-by-account basis; and
- High distribution customer load (i.e., residential, commercial, light industrial) derived using the high to reference bandwidth from the March 2020 Load Forecast Monte Carlo modelling.

Due to the COVID-19 pandemic, it was important to capture the potential for adverse impacts impacts and a scenario with little or no growth. The December 2020 low uncertainty band is the sum of the following discrete scenarios:

- Low EV forecast;
- Low large industrial forecast developed on an account-by-account basis;
- Low distribution customer load (i.e., residential, commercial, other sub-sector of light industrial) was assumed to remain at fiscal 2021 forecasted level; and
- Low light industrial forecast for wood, oil and gas, and mettalurgical coal sub-sectors using market assumptions aligned with low large industrial forecast.

As part of its continuing improvement activities, BC Hydro will be engaging a third-party consultant to review our overall methodology for developing load forecast uncertainty bands, including the use of Monte Carlo simulation modellin g. Results of the investigation will be considered in future load forecasts.

The sections below elaborate on the methodology and provide the results of the uncertainty analysis.

8.2.1 Residential

The high and low residential load forecasts were developed based on the following assumptions:

- the high residential load forecast was derived by applying the high to reference bandwidth from the March 2020 Load Forecast Monte Carlo analysis of the distribution load to the December 2020 Reference Load forecast. For example, in a given year if the March 2020 high case was x% higher than the March 2020 reference case, we increased the December 2020 reference case in that year by x% to determine the high case.
- the low residential load forecast is assumed to remain the same as the fiscal 2021 reference forecast model projections.

Table 8-1 below shows the high, reference, and low residential load forecasts. These forecasts are after adjustments fo rate impacts and, DSM , and as described in section 7.1, they include 85 percent of our low, reference, and high EV load forecasts.

Table 8-1 – Residential High, Reference, and Low Load Forecasts After Adjustments

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
Actual			
F2015	17,973	17,973	17,973
F2016	18,019	18,019	18,019
F2017	17,952	17,952	17,952
F2018	17,997	17,997	17,997
F2019	17,876	17,876	17,876
F2020	18,349	18,349	18,349
Forecast			
F2021	20,268	19,799	19,812
F2022	20,314	19,789	19,778
F2023	20,262	19,678	19,697
F2024	20,540	19,892	19,664
F2025	20,752	20,033	19,604
F2026	21,065	20,250	19,614
F2027	21,404	20,494	19,605
F2028	21,832	20,809	19,613
F2029	22,253	21,112	19,630
F2030	22,746	21,458	19,650
F2031	23,259	21,812	19,670
F2032	23,826	22,215	19,708
F2033	24,343	22,593	19,760
F2034	24,946	23,019	19,826
F2035	25,549	23,460	19,893
F2036	26,229	23,948	19,965
F2037	26,835	24,379	20,038
F2038	27,467	24,852	20,144
F2039	28,083	25,328	20,267
F2040	28,716	25,833	20,409
F2041	29,346	26,360	20,620
Compound Annual Growth Rates			
5-year History CAGR (F15 to F20)	0.4%	0.4%	0.4%
5-year CAGR (F20 to F25)	2.5%	1.8%	1.3%
10-year CAGR (F20 to F30)	2.2%	1.6%	0.7%
20-year CAGR (F20 to 40)	2.3%	1.7%	0.5%

8.2.2 Commercial

Similar to the residential sector, the high and low commercial load forecasts were developed based on the following assumptions:

- the high commercial load forecast was derived by applying the high to reference bandwidth from the March 2020 Load Forecast Monte Carlo analysis of the distribution load to the December 2020 Reference Load forecast. For example, in a given year if the March 2020 high case was x% higher than the March 2020 reference case, we increased the December 2020 reference case in that year by x% to determine the high case.

- the low commercial load forecast is assumed to remain the same as the fiscal 2021 reference forecast model projections.

Table 8-2 below shows the high, reference, and low commercial load forecasts. These forecasts are after adjustments for rate impacts and DSM , and as described in section 7.1, they include 15 percent of our low, reference and high EV load forecasts.

Table 8-2 –Commercial High, Reference, and Low Load Forecast After Adjustments

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
Actual			
F2015	14,539	14,539	14,539
F2016	14,345	14,345	14,345
F2017	14,576	14,576	14,576
F2018	14,494	14,494	14,494
F2019	14,557	14,557	14,557
F2020	14,336	14,336	14,336
Forecast			
F2021	13,168	12,864	12,873
F2022	14,010	13,654	12,821
F2023	14,366	13,968	12,729
F2024	14,346	13,921	12,666
F2025	14,274	13,820	12,585
F2026	14,267	13,774	12,547
F2027	14,243	13,723	12,500
F2028	14,250	13,698	12,464
F2029	14,236	13,655	12,426
F2030	14,249	13,627	12,399
F2031	14,262	13,598	12,370
F2032	14,285	13,580	12,342
F2033	14,285	13,556	12,321
F2034	14,318	13,544	12,302
F2035	14,342	13,537	12,285
F2036	14,392	13,543	12,270
F2037	14,425	13,536	12,258
F2038	14,467	13,543	12,253
F2039	14,498	13,543	12,242
F2040	14,546	13,558	12,242
F2041	14,619	13,605	12,282
Compound Annual Growth Rates			
5-year History CAGR (F15 to F20)	(0.3%)	(0.3%)	(0.3%)
5-year CAGR (F20 to F25)	(0.1%)	(0.7%)	(2.6%)
10-year CAGR (F20 to F30)	(0.1%)	(0.5%)	(1.4%)
20-year CAGR (F20 to 40)	0.1%	(0.3%)	(0.8%)

8.2.3 Light Industrial

The high and low light industrial forecasts were developed based on the following assumptions:

- the other sub-sector high load forecast is derived by applying the March 2020 high to reference Monte Carlo bandwidth in the same manner as the residential and commercial forecasts.
- the other sub-sector low load forecast is assumed to remain the same as the fiscal 2021 reference forecast model projections.

- discrete high and low forecasts were produced for wood, oil and gas, and metallurgical coal using market assumptions aligned with the corresponding large industrial segments described in section 8.2.4.

Table 8-3 below shows the low, reference, and high light industrial load forecasts.

Table 8-3 Light Industrial High, Reference, and Low Forecasts After Adjustments

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
Actual			
F2015	4,227	4,227	4,227
F2016	4,148	4,148	4,148
F2017	4,275	4,275	4,275
F2018	4,364	4,364	4,364
F2019	4,422	4,422	4,422
F2020	4,311	4,311	4,311
Forecast			
F2021	4,547	4,326	4,098
F2022	4,963	4,628	4,167
F2023	5,315	4,825	4,171
F2024	5,369	4,810	4,112
F2025	5,452	4,825	4,073
F2026	5,482	4,841	4,034
F2027	5,515	4,867	4,006
F2028	5,552	4,896	3,977
F2029	5,602	4,913	3,952
F2030	5,613	4,917	3,928
F2031	5,643	4,935	3,905
F2032	5,666	4,952	3,879
F2033	5,693	4,977	3,862
F2034	5,729	5,006	3,850
F2035	5,761	5,037	3,841
F2036	5,800	5,071	3,832
F2037	5,834	5,101	3,821
F2038	5,870	5,134	3,811
F2039	5,911	5,172	3,803
F2040	5,959	5,215	3,800
F2041	6,027	5,279	3,812
Compound Annual Growth Rates			
5-year History CAGR (F15 - F20)	0.4%	0.4%	0.4%
5-year CAGR (F20 -F25)	4.8%	2.3%	(1.1%)
10-year CAGR (F20 - F30)	2.7%	1.3%	(0.9%)
20-year CAGR (F20 - F40)	1.6%	1.0%	(0.6%)

8.2.4 Large Industrial

The high and low load forecasts for the large industrial sector are developed at a customer level, using the same methodology as the reference forecast, with different market assumptions. This section provides the major assumptions and results for all sub-sector and segment forecasts.

8.2.4.1 Metal Mining

The high forecast was developed base on the following market assumptions:

- higher than anticipated global economic growth and associated increased demand for copper,
- no lasting impact of the COVID-19 pandemic.
- reduced trade tensions,
- increased electrification rates in the transportation and manufacturing sectors,
- increased demand for electronics and electrical products,
- increased industrial development, which increases demand for machinery and equipment. The expansion of the power sector in China and India increases demand for wires and cables,
- as demand continues to grow at higher than expected rate, higher cost copper supply is brought into production, increasing th e long-term marginal cost to approximately $US4/lb, and
- life expansion and equipment upgrades for certain projects beyond expected assumptions.

The low forecast was developed based on the following market assumptions:

- aggressive mine supply growth with projects in South America, Central Africa and other parts of the world over the next few years,
- long-lasting impacts of COVID-19 in major economies that decrease copper demand,
- no mine disruptions weighing on supply,
- demand erosion due to substitution effects from other sources (aluminium, steel, composite materials) and rise in scrap metal recovery, and
- prices drop to $US2/lb in the next couple of years. As mines don't recoup total costs (including cost for sustaining production), many B.C. metal mines shut down production. The mines are not replaced by future additions due to the low-price environment and reduced B.C. competitiveness relative to other jurisdictions (domestic and foreign).

The high, reference and low metal mining forecasts are shown in Table 8-4.

Table 8-4 Metal Mining High, Reference, and Low Forecasts After Adjustments

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
Actual			
F2015	3,247	3,247	3,247
F2016	3,338	3,338	3,338
F2017	3,320	3,320	3,320
F2018	3,291	3,291	3,291
F2019	3,270	3,270	3,270
F2020	3,285	3,285	3,285
Forecast			
F2021	3,324	3,320	3,167
F2022	3,470	3,367	2,487
F2023	3,563	3,405	2,068
F2024	3,763	3,388	1,811
F2025	4,187	3,443	1,787
F2026	4,512	3,494	1,292
F2027	5,289	3,634	1,273
F2028	5,613	3,723	1,264
F2029	5,770	3,705	407
F2030	5,750	3,683	394
F2031	5,808	3,665	383
F2032	5,808	3,658	374
F2033	5,809	3,635	355
F2034	5,833	3,622	345
F2035	5,868	3,609	334
F2036	5,916	3,595	322
F2037	5,976	3,581	311
F2038	6,049	3,567	299
F2039	6,137	3,553	288
F2040	6,239	3,540	276
F2041	6,363	3,546	270
Compound Annual Growth Rates			
5-year History CAGR (F15 to F20)	0.2%	0.2%	0.2%
5-year CAGR (F20 to F25)	5.0%	0.9%	(11.5%)
10-year CAGR (F20 to F31)	5.8%	1.2%	(19.1%)
20-year CAGR (F20 to F41)	3.3%	0.4%	(11.6%)

8.2.4.1.1 Metallurgical Coal

The high forecast was developed based on the following market assumptions:

- higher than expected demand for steel in Asia,
- no lingering effects of COVID-19 pandemic on Chinese and US economies,
- potential disruptions to Australian coal supply, and
- prices increase to a long-term level $US175/tonne, which is sufficient to incent new supply additions.

The low forecast was developed based on the following market assumptions:

- lower than expected demand for steel in Asia,
- prolonged and long lasting COVID-19 effects reduce the demand for metallurgical coal worldwide,
- expansion of Australian coal supply, and
- prices drop to $US100/tonne below the estimated long-term operating cost of 75 per cent of the world's seaborne metallurgical coal production.

The high, reference, and low metallurgical coal forecasts are shown in Table 8-5.

Table 8-5 Metallurgical Coal High, Reference, and Low forecasts After Adjustments

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
Actuals			
F2015	560	560	560
F2016	544	544	544
F2017	562	562	562
F2018	589	589	589
F2019	574	574	574
F2020	578	578	578
Forecast			
F2021	604	603	545
F2022	660	627	549
F2023	667	628	541
F2024	690	634	533
F2025	798	629	527
F2026	798	627	514
F2027	918	644	425
F2028	976	700	422
F2029	1,170	697	368
F2030	1,175	703	357
F2031	1,173	699	349
F2032	1,176	798	348
F2033	1,174	795	342
F2034	1,171	792	337
F2035	1,169	789	332
F2036	1,166	786	327
F2037	1,164	783	322
F2038	1,161	780	317
F2039	1,159	777	312
F2040	1,157	774	307
F2041	1,157	776	317
Compound Annual Growth Rates			
5-year History CAGR (F15 to F20)	0.6%	0.6%	0.6%

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
5-year CAGR (F20 to F25)	6.7%	1.7%	(1.8%)
10-year CAGR (F20 to F30)	7.4%	2.0%	(4.7%)
20-year CAGR (F20 to F40)	3.5%	1.5%	(3.1%)

8.2.4.2 Mining Summary

Table 8-6 shows the high, reference, and low forecasts for the mining sub-sector. The forecast for this sub-sector mirrors the forecast for metal mining segment since metal mining represents approximately 85 per cent of the mining load.

Table 8-6 Mining Sub-Sector High, Reference, and Low Forecasts After Adjustments

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
Actual			
F2015	3,807	3,807	3,807
F2016	3,882	3,882	3,882
F2017	3,883	3,883	3,883
F2018	3,880	3,880	3,880
F2019	3,844	3,844	3,844
F2020	3,863	3,863	3,863
Forecast			
F2021	3,928	3,924	3,711
F2022	4,130	3,994	3,036
F2023	4,230	4,033	2,608
F2024	4,454	4,022	2,344
F2025	4,985	4,072	2,315
F2026	5,309	4,121	1,805
F2027	6,208	4,279	1,699
F2028	6,590	4,424	1,686
F2029	6,939	4,401	775
F2030	6,926	4,386	751
F2031	6,981	4,365	732
F2032	6,984	4,455	722
F2033	6,983	4,430	697
F2034	7,005	4,415	682
F2035	7,037	4,398	666
F2036	7,082	4,381	649
F2037	7,140	4,364	633
F2038	7,211	4,347	616
F2039	7,296	4,331	600
F2040	7,396	4,314	583
F2041	7,520	4,322	588
Compound Annual Growth Rates			
5-year History CAGR (F15 to F20)	0.3%	0.3%	0.3%
5-year CAGR (F20 to F25)	5.2%	1.1%	(9.7%)

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
10-year CAGR (F20 to F30)	6.0%	1.3%	(15.1%)
20-year CAGR (F20 to F40)	3.3%	0.6%	(9.0%)

8.2.4.3 Pulp and Paper

High and low pulp and paper load forecasts were developed and included in the high and low forecasts for the forestry sub-sector. Table 8-7 shows the high, reference, and low forecasts..

Table 8-7 Pulp and Paper Segment High, Reference, and Low Forecasts After Adjustments

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
Actual			
F2015	5,262	5,262	5,262
F2016	4,726	4,726	4,726
F2017	4,173	4,173	4,173
F2018	4,234	4,234	4,234
F2019	3,997	3,997	3,997
F2020	3,561	3,561	3,561
Forecast			
F2021	3,248	2,651	1,824
F2022	3,783	2,476	1,477
F2023	3,992	2,449	1,291
F2024	3,988	2,370	1,148
F2025	3,898	2,284	1,093
F2026	3,890	2,279	1,097
F2027	3,874	2,262	1,081
F2028	3,861	2,248	1,068
F2029	3,842	2,227	1,049
F2030	3,819	2,202	1,026
F2031	3,801	2,181	1,007
F2032	3,786	2,166	993
F2033	3,772	2,152	979
F2034	3,758	2,137	965
F2035	3,743	2,122	950
F2036	3,727	2,105	934
F2037	3,698	2,076	905
F2038	3,682	2,060	889
F2039	3,666	2,044	873
F2040	3,651	2,028	857
F2041	3,655	2,036	862

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
Compound Annual Growth Rates			
5-year History CAGR (F15 to F20)	(8.0%)	(8.0%)	(8.0%)
5-year CAGR (F20 to F25)	2.4%	(8.0%)	(20.6%)
10-year CAGR (F20 to F30)	1.0%	(4.4%)	(11.4%)
20-year CAGR (F20 to F40)	0.3%	(2.6%)	(6.7%)

The high and low forecasts are not symmetric around the reference forecast. Table 7-7 shows the high forecast is proportionally higher relative to the reference forecast than is the low forecast. The high forecast assumes market conditions evolve such that publication paper customers profitably retool and expand production. For instance, our pulp and paper market consultant has identified new growing markets like wastepaper recycling, tissue and paper packaging to displace plastic. These new market opportunities represent potential mill line conversion opportunities for B.C. publication paper mills. Moreover, with wastepaper recycling, the Chinese government has banned wastepaper imports into the country to reduce water pollution. Consequently, Chinese paper recyclers are no longer able to buy wastepaper from North America. As a result, North American paper mills are being converted into wastepaper recyclers to meet growing paper demand in China with abundant supplies of low-cost wastepaper, including in B.C.

8.2.4.4 Wood Products

High and low forecasts for the wood products segment were developed and rolled up into the high and low bands for the forestry sub-sectors.

Table 8-8 shows the historical and high, reference, and low forecasts for wood products segment. The high and low forecasts are symmetrical projections around the reference forecast.

Table 8-8 – Wood Products Segment High, Reference, and Low Forecasts After Adjustments

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
Actual			
F2015	1,155	1,155	1,155
F2016	1,208	1,208	1,208
F2017	1,141	1,141	1,141
F2018	1,243	1,243	1,243
F2019	1,211	1,211	1,211
F2020	1,018	1,018	1,018
Forecast			
F2021	1,093	1,034	830
F2022	1,218	1,100	848
F2023	1,288	1,157	888
F2024	1,245	1,094	841
F2025	1,225	1,060	810
F2026	1,223	1,057	806

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
F2027	1,220	1,054	800
F2028	1,217	1,049	795
F2029	1,213	1,044	791
F2030	1,208	1,039	786
F2031	1,204	1,035	782
F2032	1,201	1,031	779
F2033	1,198	1,028	776
F2034	1,195	1,025	773
F2035	1,192	1,022	770
F2036	1,188	1,019	767
F2037	1,185	1,015	763
F2038	1,182	1,012	760
F2039	1,179	1,008	757
F2040	1,175	1,005	753
F2041	1,176	1,007	754
Compound Annual Growth Rates			
5-year History CAGR (F15 to F20)	(2.5%)	(2.5%)	(2.5%)
5-year CAGR (F20 to F25)	3.8%	0.8%	(4.5%)
10-year CAGR (F20 to F30)	1.7%	0.2%	(2.6%)
20-year CAGR (F20 to F40)	0.7%	(0.1%)	(1.5%)

The high forecast assumes higher than expected demand from U.S. housing starts and lumber exports to China. While this forecast assumes high lumber prices, increased production is assumed to be constrained by increased logging and stumpage costs resulti ng from declining fibre supply.

The low forecast assumes some mills operate at reduced capacity or are closed. This is assumed to occur as a result of weaker demand from the U.S. and Chinese markets and deteriorating fibre supply. For the U.S. market, housing starts are assumed to only moderately rise and the softwood lumber dispute to remains unresolved.

The low forecast also assumes slower economic growth in China with increased market competition for B.C. wood products from o ther jurisdictions (Russia, New Zealand, and Europe). Both U.S. and Chinese market assumptions result in lower lumber prices for B.C. producers. In addition, wood harvesting costs are assumed to increase as a result wildfire and mountain pine beetle effects o n fibre supply. The net effect of the market and fibre supply conditions is assumed to trigger mill closures or mills to operate at lower production levels.

8.2.4.5 Chemical

High and low forecasts for the chemical segment were developed and included in the forestry sub-sector's high and low bands. Table 8-9 shows the high, reference, and low forecasts.

Table 8-9 Chemical Segment High, Reference, and Low Forecasts After Adjustments

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
Actual			
F2015	1,541	1,541	1,541
F2016	1,456	1,456	1,456
F2017	1,409	1,409	1,409
F2018	1,477	1,477	1,477
F2019	1,309	1,309	1,309
F2020	1,313	1,313	1,313
Forecast			
F2021	1,311	1,252	1,197
F2022	1,451	1,307	1,195
F2023	1,532	1,371	1,246
F2024	1,533	1,372	1,247
F2025	1,532	1,370	1,246
F2026	1,534	1,372	1,248
F2027	1,534	1,372	1,248
F2028	1,534	1,372	1,248
F2029	1,534	1,372	1,248
F2030	1,534	1,372	1,248
F2031	1,534	1,372	1,248
F2032	1,534	1,372	1,248
F2033	1,534	1,372	1,248
F2034	1,534	1,372	1,248
F2035	1,534	1,372	1,248
F2036	1,534	1,372	1,248
F2037	1,534	1,372	1,248
F2038	1,534	1,372	1,248
F2039	1,534	1,372	1,248
F2040	1,534	1,372	1,248
F2041	1,534	1,372	1,248
Compound Annual Growth Rates			
5-year History CAGR (F15 to F20)	(3.2%)	(3.2%)	(3.2%)
5-year CAGR (F20 to F25)	3.1%	0.9%	(1.0%)
10-year CAGR (F20 to F30)	1.6%	0.4%	(0.5%)
20-year CAGR (F20 to F40)	0.8%	0.2%	(0.3%)

There is relatively low uncertainty in the loads that make up the chemical segment. This is demonstrated in the historical sales between fiscal 2013 and fiscal 2020. Besides the aforementioned plant closure, there is little historical load variation. Going forward, we do not expect any material operational changes by customers within the chemical segment. We assume chemical plants have the ability to sustain operations by exporting product in the event there are pulp and paper mill curtailments in B.C. The high forecast is higher in magnitude relative to the reference forecast than is the low forecast. This is based on the assumption that prices and market conditions in the pulp and paper and oil and gas segments will be remain favourable.

8.2.4.6 Forestry Summary

Table 8-10 shows the forestry high, reference, and low forecast after adjusting for rate impacts and DSM.

Table 8-10 Forestry Sub-Sector High, Reference, and Low Forecasts After Adjustments

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
Actual			
F2015	7,959	7,959	7,959
F2016	7,390	7,390	7,390
F2017	6,723	6,723	6,723
F2018	6,954	6,954	6,954
F2019	6,517	6,517	6,517
F2020	5,792	5,792	5,792
Forecast			
F2021	5,652	4,937	3,850
F2022	6,452	4,883	3,520
F2023	6,813	4,977	3,425
F2024	6,766	4,835	3,236
F2025	6,655	4,714	3,148
F2026	6,646	4,709	3,150
F2027	6,627	4,688	3,128
F2028	6,613	4,669	3,111
F2029	6,589	4,644	3,088
F2030	6,562	4,613	3,060
F2031	6,539	4,588	3,037
F2032	6,521	4,569	3,019
F2033	6,505	4,552	3,003
F2034	6,488	4,535	2,986
F2035	6,469	4,516	2,968
F2036	6,450	4,496	2,948
F2037	6,417	4,464	2,916
F2038	6,398	4,444	2,896
F2039	6,379	4,425	2,877
F2040	6,360	4,406	2,859
F2041	6,366	4,415	2,864
Compound Annual Growth Rates			
5-year History CAGR (F15 to F20)	(6.2%)	(6.2%)	(6.2%)
5-year CAGR (F20 to F25)	2.8%	(4.0%)	(11.5%)
10-year CAGR (F20 to F30)	1.3%	(2.3%)	(6.2%)
20-year CAGR (F20 to F40)	0.5%	(1.4%)	(3.5%)

8.2.4.7 SHALE GAS

Table 8-11 shows the high, reference, and low forecast of sales to the shale gas segment..

Table 8-11 - Shale Gas Segment High, Reference, and Low Forecasts After Adjustments

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
Actual			
F2015	142	142	142
F2016	440	440	440
F2017	555	555	555
F2018	710	710	710
F2019	1,416	1,416	1,416
F2020	1,540	1,540	1,540
Forecast			
F2021	1,646	1,444	1,189
F2022	1,746	1,552	1,249
F2023	2,353	1,966	1,648
F2024	2,789	2,246	1,846
F2025	3,442	2,538	2,065
F2026	4,160	2,748	2,177
F2027	4,801	2,901	2,242
F2028	5,081	2,965	2,263
F2029	5,316	3,025	2,272
F2030	5,574	3,091	2,270
F2031	5,748	3,126	2,268
F2032	5,758	3,127	2,267
F2033	5,762	3,128	2,267
F2034	5,761	3,128	2,266
F2035	5,761	3,127	2,266
F2036	5,760	3,127	2,266
F2037	5,760	3,127	2,265
F2038	5,760	3,126	2,265
F2039	5,760	3,126	2,265
F2040	5,760	3,126	2,265
F2041	5,763	3,130	2,269
Compound Annual Growth Rates			
5-year History CAGR (F15 to F20)	61.1%	61.1%	61.1%
5-year CAGR (F20 to F25)	17.5%	10.5%	6.0%
10-year CAGR (F20 to F30)	13.7%	7.2%	4.0%
20-year CAGR (F20 to F40)	6.8%	3.6%	1.9%

The high shale gas forecast assumes higher natural gas production growth to serve higher LNG terminal requirements, higher downstream gas and liquids exports to stronger North American markets and higher electrification percentages for new production facilities. The low shale gas forecast assumes slower production growth trending rise in natural gas production to supply lower LNG terminal requirements, weaker North American natural gas demand, and lower electrification percentage for new production facilities.

8.2.4.8 Other Oil and Gas (including LNG) Summary

Table 8-12 shows the oil and gas (including LNG) sub-sector. This includes high and low forecasts for the other large oil and gas operations segment were developed and aggregated within the overall sub-sector. The high and low forecasts for this segment are primarily driven by LNG terminal assumptions.

Table 8-12 Other Oil and Gas (including LNG) Sub-sector High, Reference, and Low Forecasts After Adjustments

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
Actual			
F2015	973	973	973
F2016	836	836	836
F2017	818	818	818
F2018	797	797	797
F2019	861	861	861
F2020	794	794	794
Forecast			
F2021	951	788	728
F2022	981	844	747
F2023	1,570	992	808
F2024	2,126	1,718	1,089
F2025	3,086	2,504	1,918
F2026	4,415	3,218	2,135
F2027	5,501	3,362	2,143
F2028	6,514	3,581	2,141
F2029	8,386	3,577	2,138
F2030	8,501	3,574	2,135
F2031	8,498	3,570	2,131
F2032	8,494	3,567	2,128
F2033	8,491	3,563	2,125
F2034	8,488	3,560	2,122
F2035	8,484	3,556	2,118
F2036	8,479	3,551	2,113
F2037	8,475	3,547	2,109
F2038	8,470	3,543	2,105
F2039	8,466	3,538	2,100
F2040	8,462	3,534	2,096
F2041	8,460	3,532	2,093
Compound Annual Growth Rates			
5-year History CAGR (F15 to F20)	(4.0%)	(4.0%)	(4.0%)
5-year CAGR (F20 to F25)	31.2%	25.8%	19.3%
10-year CAGR (F20 to F30)	26.8%	16.2%	10.4%
20-year CAGR (F20 to F40)	12.6%	7.8%	5.0%

The risk profile for this segment is asymmetrical in that the potential for higher load growth relative to what is reflected in the load forecast is greater than the potential for lower load. This asymmetry is primarily due to LNG terminals.

8.2.4.9 Other Large Industrial

Table 8-13 shows the high, reference, and low forecasts for the other large industrial customers, after adjustments.

The high forecast was developed based on the following assumptions:

- no adverse effects from COVID-19 pandemic beyond fiscal 2021,
- higher global economic growth results in higher demand for industrial products and shipping affecting cement plant production, ports, terminals and manufacturing,
- higher life expectancy and load from cryptocurrency and data centres, and
- higher than anticipated growth for universities and new customers.

The low forecast was developed based on the following assumptions:

- COVID-19 pandemic has a long-lasting effect on customers such as universities or airports which are deferring expansions,
- lower global economic growth results in lower demand for products and shipping affecting cement plant production, ports, terminals and manufacturing, and
- no incremental growth from cryptocurrency and data centres.

Table 8-13 Other Large Industrial Sub-Sector High, Reference, Low Forecasts After Adjustments

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
Actual			
F2015	1,173	1,173	1,173
F2016	1,149	1,149	1,149
F2017	1,126	1,126	1,126
F2018	1,171	1,171	1,171
F2019	1,136	1,136	1,136
F2020	1,144	1,144	1,144
Forecast			
F2021	1,178	1,072	984
F2022	1,416	1,165	995
F2023	1,604	1,215	1022
F2024	1,739	1,220	962
F2025	1,816	1,154	912
F2026	1,817	1,100	909
F2027	1,820	1,106	905
F2028	1,825	1,103	902
F2029	1,828	1,098	898
F2030	1,831	1,094	894
F2031	1,841	1,104	891
F2032	1,851	1,109	888
F2033	1,861	1,118	885
F2034	1,872	1,122	882
F2035	1,882	1,130	880
F2036	1,893	1,135	877
F2037	1,904	1,143	875
F2038	1,915	1,148	872
F2039	1,927	1,157	870
F2040	1,939	1,163	868
F2041	1,954	1,175	868

Fiscal year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
Compound Annual Growth Rates			
5-year History CAGR (F15 to F20)	(0.5%)	(0.5%)	(0.5%)
5-year CAGR (F20 to F25)	9.7%	0.2%	(4.4%)
10-year CAGR (F20 to F30)	4.8%	(0.4%)	(2.4%)
20-year CAGR (F20 to F40)	2.7%	0.1%	(1.4%)

8.2.5 Electrification

One major source of uncertainty in this forecast is the level of electrification that will be achieved. Electrification is a term used to refer to switching from the use of fossil fuels to the use of electricity from clean energy sources, resulting in reduced greenhouse gas (GHG) emissions. BC Hydro has been supporting electrification and greenhouse gas emission reductions for a number of years. In August 2020 BC Hydro initiated work to develop an Electrification Plan designed to consolidate the actions already underway as well as new actions to increase low carbon electrification, attract additional load, and connect customers more efficiently. The December 2020 Load Forecast was finalized prior to the Electrification Plan. Because the Electrification Plan consolidates actions already underway, some plan components such as the CleanBC-driven measures described below are reflected in the December 2020 Load Forecast. Additional components and revised estimates for the existing components will be incorporated into future load forecasts as they become approved and more certain.

This section provides our estimate of loads related to the CleanBC plan which are included in the December 2020 Load Forecast and introduces an accelerated electrification scenario, which is provided as Appendix F to this report.

8.2.5.1 Estimated Loads Related to the CleanBC Plan

As with previous load forecasts, the December 2020 Load Forecast includes electrification loads that result from activities which reduce or avoid GHG emissions. The estimated electrification loads presented in this section encompass a specific set of intiatives and customer-specific assumptions, which are directly related to action and strategies outlined in the CleanBC Plan.

The December 2020 Load Forecast captures the following:

- EV load - The CleanBC Plan made a firm commitment to a Zero Electric Vehicle (ZEV) mandate that was enacted in legislation on May 20, 2019. Accordingly, the EV forecast is included in our electrification estimate.
- BC Government-Funded Fuel Switching – The estimated impact of the fuel switching component of the government-funded CleanBC Better Buildings/Homes program, which BC Hydro is administering on behalf of the Government of B.C.
- BC Hydro Low Carbon Electrification (LCE) – BC Hydro’s Low Carbon Electrification (LCE) projects/programs, described in Appendix N of BC Hydro’s Fiscal 2022 Revenue Requirements Application.
- Large Industrial Electrificaton. The CleanBC Plan includes providing clean electricity supply to natural gas production in the Peace region and increasing access to clean electricity for large operations with new transmission lines and interconnectivity to existing lines. Accordingly, forecast load growth from specific projects in the oil and gas (including LNG) sub-sector is included in the electrification estimate.

There are likely to be other electrification actions which have been or will be undertaken by some of our customers that also support provincial GHG emission reduction targets, but are not included in our estimate.

The estimated electrification load in the Load Forecast from the areas listed above, allocated by major customer sector, is provided in Table 8-14. By fiscal 2025, we estimate the December 2020 Load Forecast includes approximately 3,300 GWh of electrification load related to the CleanBC Plan. This will increase over the forecast period.

Table 8-14 - Electrification Load Included in the Load Forecast

Electrification Loads (GWh)	Fiscal Year	Total	Load Forecast Sector Allocation			
			Residential	Commercial	Light Industrial	Large Industrial
Light Duty EV Forecast	F2025	**593**	504	89	0	0
	F2030	**1,559**	1,325	234	0	0
	F2035	**2,992**	2,543	449	0	0
	F2040	**4,698**	3,993	705	0	0
Low Carbon Electrification (LCE) Program Loads	F2025	**148**	36	48	28	36
	F2030	**147**	36	48	28	35
	F2035	**127**	29	46	28	24
	F2040	**51**	0	12	28	11
Large Industrial Low Carbon Electrification (LCE) Project Loads	F2025	**2,573**	0	0	0	2,573
	F2030	**4,147**	0	0	0	4,147
	F2035	**4,096**	0	0	0	4,096
	F2040	**4,052**	0	0	0	4,052
Total CleanBC Related Load in Load Forecast	F2025	**3,313**	**539**	**137**	**28**	**2,609**
	F2030	**5,853**	**1,361**	**282**	**28**	**4,182**
	F2035	**7,215**	**2,572**	**495**	**28**	**4,120**
	F2040	**8,801**	**3,993**	**717**	**28**	**4,063**

Our estimated electrification load reflected in the Load Forecast is provided again in Table 3.x, allocated by the following CleanBC Plan categories: Transportation, Built Environment and Industry.

Table 8-15 - Estimated Electrification Load in Load Forecast by Category

Fiscal Year	Transportation (GWh)	Built Environment (GWh)	Industry (GWh)	Total (GWh)
F2025	596	80	2,637	**3,313**
F2030	1,563	80	4,210	**5,853**
F2035	2,992	75	4,148	**7,215**
F2040	4,698	12	4,091	**8,801**

8.2.5.2 Accelerated Electrification Scenario

In addition to the low and high uncertainty bands, BC Hydro worked with a consultant to develop an Accelerated Electrification Scenario for use in the 2021 IRP.

The Government of B.C. has legislated targets for reducing greenhouse gas emissions 40 per cent below 2007 levels by 2030, 60 per cent by 2040, and 80 per cent by 2050. The Government of B.C. has also introduced an interim GHG reductio n target of 16 per cent by

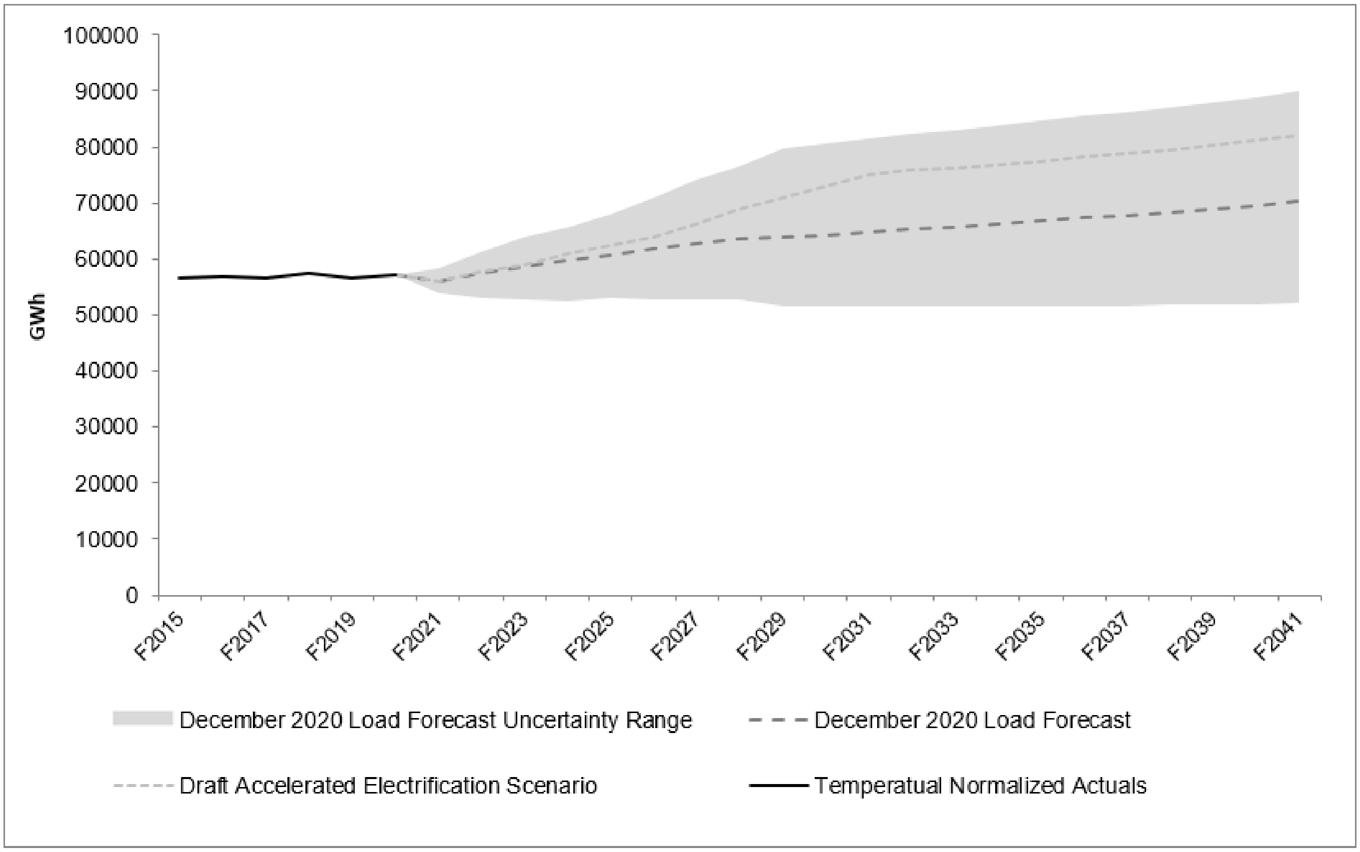
2025. The CleanBC Plan sets out a path towards the 2030 target, which includes electrification of a variety of energy end-uses supplied by fossil fuels.

BC Hydro engaged Navius Research to develop an electrification scenario that estimates the impact on load growth if all of the provincial GHG reduction targets are met over the milestone years of 2025, 2030 and 2040. The estimated loads in this scenario are incremental to the December 2020 Load Forecast. The details of the study are presented in Appendix F of this report and illustrate that by fiscal 2025, electricity consumption could be around 1,000 GWh higher than the December 2020 Load Forecast. By fiscal 2030 electricity demand could be around 8,000 GWh higher, with most of the incremental growth in electricity demand coming from the natural gas sector and electrification of residential and commercial sector buildings and transportation.

8.2.6 Total System Uncertainty

The December 2020 Load Forecast uncertainty bands and Accelerated Electrification Scenario are shown in Figure 8.1

Figure 8.1 – December 2020 Load Forecast, Total Integrated System Uncertainty Bands and Accelerated Electrification Scenario

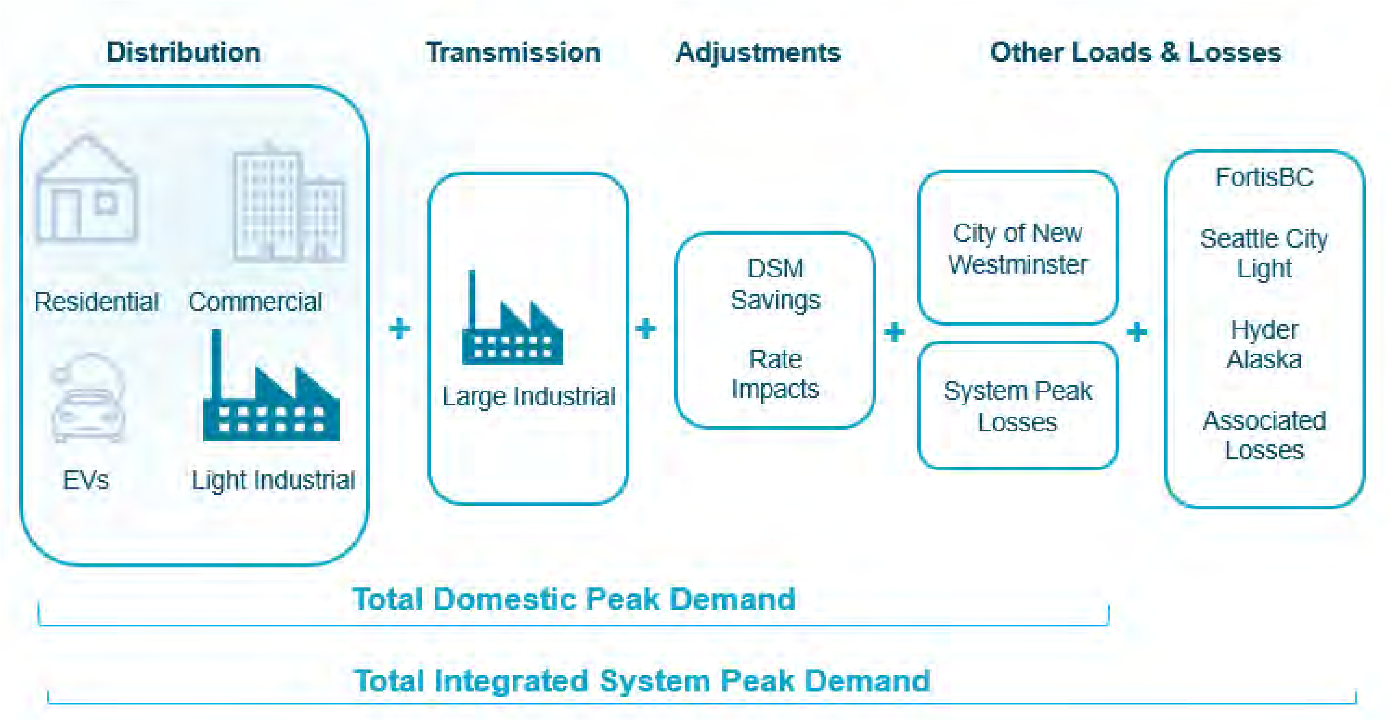


9.0 Peak Demand Forecast

9.1 PEAK DESCRIPTION

BC Hydro's peak demand is defined as the maximum expected amount of electricity consumed in a single hour under an average cold temperature assumption referred to as the design temperature. BC Hydro is a winter peaking utility, as its demand is more sensitive to colder temperatures than warmer temperatures. The total BC Hydro system typically reaches its annual peak on a cold winter day between 5:00 pm and 6:00 pm. Vancouver Island has a morning and an evening peak as residential space heating is a larger component of the Vancouver Island load. Figure 9.1 below shows the build-up of the Total Domestic Peak Demand forecast and the Total Integrated System Peak forecast.

Figure 9-1 – Total Domestic and Total Integrated System Peak Forecast Build Up



The domestic peak includes distribution substation peaks, transmission customer peaks and the peak demand of the City of New Westminster and system transmission losses. The Integrated system peak demand is the Domestic peak demand plus the peak demands from the other served utilities including FortisBC, Seattle City Light, Hyder Alaska and the system transmission losses associated with their demand.

The largest component of the domestic peak demand is the distribution peak which is estimated to be 10,253 MW in fiscal 2041. The distribution peak is the total peak demand for all distribution substations (including distribution losses) coincident (or at the time) when our system is reaching is highest point. The city of New Westminster is also part of the total domestic system as BC Hydro provides energy and capacity on a bulk system to the two substations that serve the City of New Westminster. The second largest component of the domestic peak is the coincident transmission peak demand which is forecast to be 1,984 MW fiscal 2041. The transmission peak demand is the total coincident peak demand of all large industrial customers connected at system at transmission voltage. The transmission peak forecast is developed for each of large industrial customer using the drivers and inputs that are used to develop the energy sales forecast described in section 6. Distribution peak demand is the most sensitive to ambient temperature. The future demand is driven by various factors including residential accounts and growth in distribution energy sales, which in turn is driven by economic forecasts. In addition, larger discrete loads such as shopping malls, waste treatment facilities and other infrastructure projects contribute to the peak at specific distribution substations are also considered.

Transmission peak demand is responsive to external market conditions and changes in demands for BC's key industrial commodities such as wood, oil and gas, pulp and paper, metallurgical coal, and metals.

9.2 PEAK DEMAND FORECAST METHODOLOGY

This section provides a high-level overview of how the distribution, electric vehicles, transmission and total system peak demand forecast is developed.

9.2.1 Distribution Peak Methodology

At the distribution level, electricity demand is closely linked to the historical trends in distribution substation load growth, peak intensity coefficients and the energy forecast for residential, commercial and light industrial sectors.

The distribution peak forecast is developed using a regression model referred to as the distribution peak guideline forecast and prepared for 15 different planning areas. The forecast provides forecast for growth for all of the substations serving distribution customers in that area and it is used internally for development of substation forecasts. The main drivers used in the model are the forecasts of distribution energy and the number of residential customer accounts, which is driven by housing starts.

The equation for the distribution peak guideline can be summarized as:

$$Area\ Peak\ Demand = \overbrace{kVA/Account * Accounts}^{(Residential\ Peak)} + \overbrace{kVA/kWh * Energy\ (kWh)}^{(Light\ industrial\ and\ Commercial\ Peak)}$$

The Area Peak Demand (i.e., base peak load) is adjusted with following peak demand forecasts to determine the Total Area Peak (reference) Guideline Forecast:

- The demand forecast of EVs,
- Overlap in codes and standards,
- Fuel Switching peak demand, and
- Additional spot loads.

Residential peak intensity is the average peak kW per residential account. Residential peak intensities are estimates for each of the 15 areas for two housing types (single family and multiple housing) and two heating types (electric and non-electric). The estimation involves a two-step process, in the first step, the raw intensity is estimated using historical load shapes. This results in the average kW/account for various heating types and housing types. In the second step, the intensities are calibrated and scaled such that peak guideline model's predicted historical peak demand (i.e., back-cast) matches the historical temperature normalized area peak over the past 10 years. This second step transforms the average kW per account into average kVA per account.

Light industrial and commercial peak intensity is the average peak per unity of energy (i.e. kW/kWh) and it is estimated using historical load shapes developed from historical data. The peak intensities are estimated for each of the 15 areas for customers greater than 35 kW and under 35 kW. The intensities are also estimated with a two-step process.

The residential accounts forecast, and light industrial and commercial energy forecast are prepared for each of the 15-distribution planning areas. The residential account forecast is prepared for two housing types (single family and multiple housing) and two heating types (electric and non-electric). The light industrial and commercial energy forecast is prepared for four regions and allocated to the 15 planning areas.

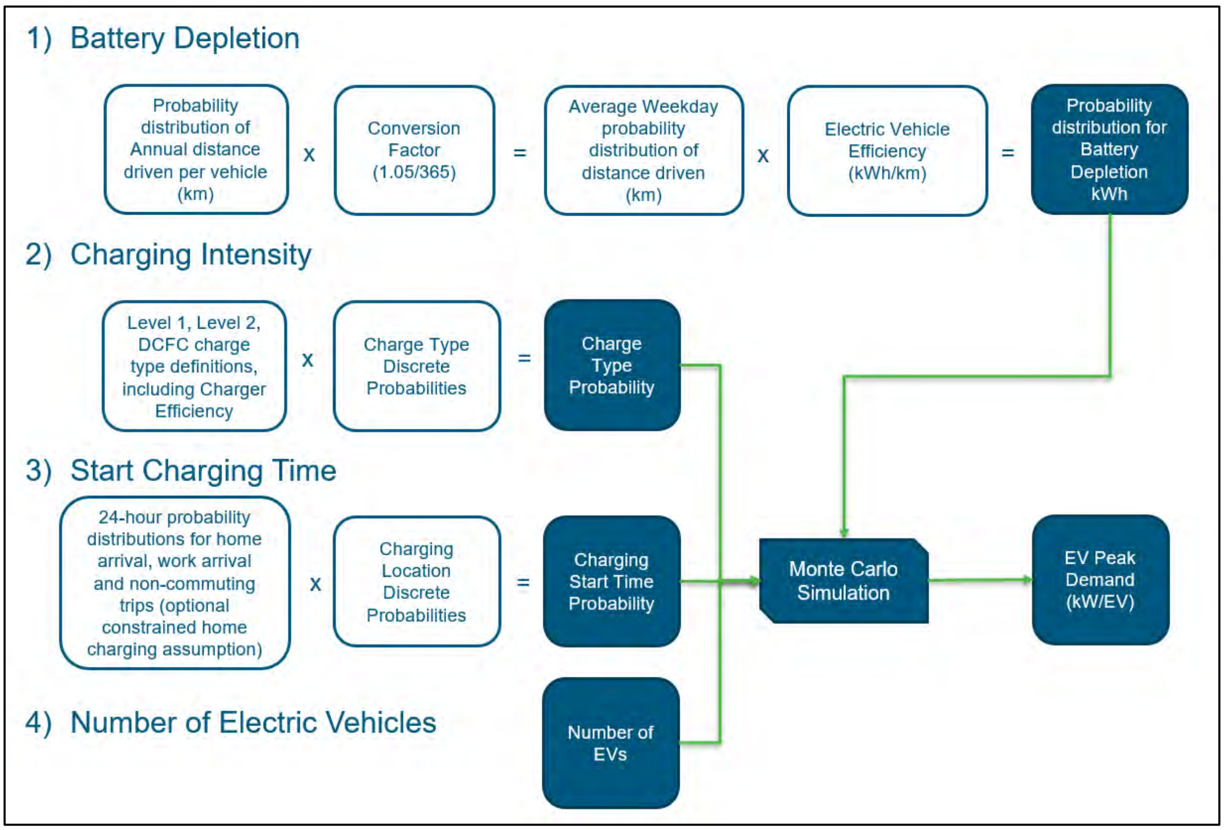
Regional power factors and coincidence factors are applied to aggregated forecasts to produce four regional coincident distribution peak forecasts. The power factors and coincident factors are based on historical averages.

A total BC Hydro distribution peak forecast is prepared as a coincident sum of the four regional distribution peak forecasts.

9.2.2 Electric Vehicle Peak Methodology

Similar to the EV model, BC Hydro's electric vehicle peak forecast is based on our in-house Electric Vehicle peak model (EV peak model). Figure 9-2 below illustrates the key inputs and calculations of our EV peak model.

Figure 9-2 Electric Vehicle Peak Model



The EV peak model has four main components:

1. Probability distribution for battery depletion in kWh. The key inputs being annual distance driven, which is converted to daily distance driven, and the average EV efficiency.
2. Charging Intensity
   a. Looking at different charging types: level 1, level 2 and DC fast charging each of which has a discrete probability,
   b. The model also accounts for charging efficiencies.
3. Charging start time probability:

a. Survey data are used to create a 24-hour probability distribution for home arrival, work arrival times plus non-commuting charging times, which includes any non-work and home related charging such as charging at the supermarket or any public charging stations.

4. Number of EVs which comes from the EV model.

All these components then feed into a Monte Carlo simulation that creates our EV peak forecast.

BC Hydro uses an additional home charging profile to reflect potential programs and incentives to shift charging behaviour to the off-peak period. The probability of charging under this profile is adjusted as follows to develop the low, reference and high EV peak forecasts.

- The high peak forecast is unconstrained, which means EV owners will charge their vehicle upon home arrival;
- The reference peak forecast is 25 per cent constrained. In this forecast, 25 per cent of EV owners will start charging their vehicle during off-peak hours; and
- The low peak forecast is 25 per cent to 75 per cent constrained, which is similar to the reference forecast with the exception that up to 75 per cent of EV owners will start charging their vehicles during off-peak hours.

9.2.3 Transmission Peak Methodology

The transmission peak demand forecast is prepared on a customer-by-customer account basis for the entire forecast period. Individual transmission customer forecasts are developed using market intelligence from BC Hydro's key account managers, historical peak demand trends, reports on industry outlooks, plus production and intensity estimates. These forecasts are aggregated into regional peak forecasts (i.e., a total transmission peak demand forecast) for each of the four main service regions. Regional coincidence factors and power factors are applied to each of these total regional peak forecasts to establish regional coincident transmission peak forecasts.

A total BC Hydro transmission peak demand forecast is prepared as a coincident sum of the four regional transmission peak forecasts.

9.2.4 Integrated System Peak Forecast Methodology

A total system peak demand forecast is prepared as the sum of the total coincident distribution peak, total coincident transmission peak, peak demands for other utilities and total system transmission losses.

The system transmission losses are assumed as 7.0 percent of the total system peak demand forecast.
The system peak demand forecast is prepared for the BC Hydro's domestic system and the total integrated system. The domestic peak demand is the sum of the total domestic distribution and transmission peaks, the peak demand of the City of New Westminster and system transmission losses. The integrated system peak demand is the domestic peak demand plus the peak demands from th e other utilities (i.e., Seattle City Light and FortisBC) and system transmission losses.

9.3 PEAK DEMAND FORECAST

BC Hydro's all-time total domestic system peak was 10,577 MW which occurred on January 14, 2020. The daily average temperature for that day recorded at the Vancouver International Airport (YVR) was -7.1 ºC colder than the design temperature of -4.7 ºC. The design temperature is the rolling average of the coldest daily average temperature over the most recent 30 years. The temperature-adjusted domestic peak for the winter of fiscal 2020 was estimated at 10,162 MW.

For the winter of fiscal 2020, the total integrated system peak forecast, including peak requirements from the other utilities served by BC Hydro, was 10,844 MW before temperature adjustments and 10,471 M, after temperature adjustments.

The integrated system peak forecast, with DSM and with rate impacts is expected to be 11,173 MW in fiscal 2025, 11,881 MW in F2031, and 13,346 MW in fiscal 2041. These increases represent growth rates of 1.3 per cent over the next five years (F2020 to

F2025), 1.2 per cent over the next 11 years (F2020 to F2031), and 1.2 per cent over the next 21 years of the forecast (fiscal 2020 to fiscal 2041).

9.3.1 Distribution Peak

The coincident distribution peak decreases more than 200 MW in fisal 2021 as a result of the drop-in commercial activity due to COVID-19 impacts, as described in section 4.3.

The compounded growth in the coincident distribution peak forecast is around 0.6 percent in the first five years (fiscal 2020 to fiscal 2025), but then slightly accelerates to 0.8 percent by fiscal 2031 and 1.2 per cent by fiscal 2041. The increase is caused by the larger impact of EVs in the latter part of the forecast, as adoption rates and total stock of EVs increase in the last ten years of the forecast horizon. Further information is provided in section 7.2.3.

Table 9-1 below shows the coincident distribution peak demand forecast after including the EV forecast and adjusting for rate impacts and DSM.

Table 9-1 Distribution Peak Demand Forecast After Adjusments

Fiscal year	December 2020 Coincident Distribution Forecast (MW)
Actual	
F2020	8,005
Forecast	
F2021	7,793
F2022	8,047
F2023	8,169
F2024	8,217
F2025	8,243
F2026	8,318
F2027	8,395
F2028	8,482
F2029	8,575
F2030	8,674
F2031	8,782
F2032	8,902
F2033	9,027
F2034	9,156
F2035	9,293
F2036	9,441
F2037	9,587
F2038	9,734
F2039	9,880
F2040	10,023
F2041	10,181
5-year CAGR (F20 to F25)	0.6%
10-year CAGR (F20 to F30)	1.6%
20-year CAGR (F20 to F40)	4.6%

9.3.2 EV Peak Forecast Results

Table 9-2 below shows the EV peak for the high, reference and low forecasts.

Table 9-2 – EV High, Reference, and Low Peak Forecasts

Fiscal Year	High EV Peak Forecast - Unconstrained (MW)	Reference EV Peak Forecast - 25% TOU (MW)	Low EV Peak Forecast - 25% to 75% (MW)
F2021	21	15	10
F2022	63	38	20
F2023	120	69	30
F2024	193	106	39
F2025	279	149	46
F2026	378	198	53
F2027	504	259	59
F2028	643	324	72
F2029	796	396	84
F2030	964	475	98
F2031	1,147	562	114
F2032	1,342	658	133
F2033	1,550	762	155
F2034	1,769	873	180
F2035	2,003	993	208
F2036	2,254	1,122	239
F2037	2,496	1,251	272
F2038	2,727	1,378	307
F2039	2,946	1,503	345
F2040	3,152	1,625	384
F2041	3,346	1,743	424

BC Hydro is constantly monitoring the growth of EVs and looking into different ways to mitigate the peak associated with EVs.

9.3.3 Transmission Peak

The annual compounded growth in the coincident large industrial (transmission) peak forecast is around 3.9 per cent in the first five years (fiscal 2020 to fiscal 2025) but decreases to 2.4 percent by fiscal 2031 and 1.2 per cent by fiscal 2041. The increase up to fiscal 2026 is caused mainly by additions in the oil and gas (including LNG) sub-sector, as the transmission sector growth remains relatively flat after fiscal 2026.

For more details regarding the transmission subsectors (mining, oil and gas, forestry or others), refer to the section 6 - Large Industrial Forecast. The transmission peak mirrors the growth of the transmission energy forecast.

Table 9-3 below shows the coincident transmission peak forecast after adjusting for rate impacts and DSM..

Table 9-3 - Transmission Peak Demand Forecast After Adjustments

Fiscal Year	Coincident Transmission Peak Forecast (MW)
Actual	
F2020	1,440
Forecast	
F2021	1,468
F2022	1,474
F2023	1,543
F2024	1,644
F2025	1,746
F2026	1,797
F2027	1,844
F2028	1,866
F2029	1,868
F2030	1,869
F2031	1,865
F2032	1,872
F2033	1,871
F2034	1,868
F2035	1,864
F2036	1,861
F2037	1,857
F2038	1,854
F2039	1,851
F2040	1,848
F2041	1,849
Compound Annual Growth Rates	
5-year CAGR (F20 - F25)	3.9%
10-year CAGR (F20 - F30)	5.4%
20-year CAGR (F20 - F40)	5.1%

9.3.4 Integrated System Peak

Table 9-4 shows the total integrated system peak demand forecasts after adjusting for rate impacts and DSM.. The integrated peak demand forecast is the sum of the peak forecast for coincident distribution, transmission, and other utilities plus system transmission losses.

Table 9-4 – Total Integrated Peak Demand Reference Forecast After Adjustments

Fiscal Year	Total Integrated Peak Forecast (MW)
Actual	
F2020	10,471
Forecast	
F2021	10,405
F2022	10,684
F2023	10,887
F2024	11,041
F2025	11,173
F2026	11,307
F2027	11,439
F2028	11,557
F2029	11,660
F2030	11,768
F2031	11,881
F2032	12,018
F2033	12,152
F2034	12,288
F2035	12,433
F2036	12,589
F2037	12,743
F2038	12,898
F2039	13,053
F2040	13,204
F2041	13,376
Compound Annual Growth Rates	
5-year CAGR (F20 - F25)	1.3%
10-year CAGR (F20 - F30)	2.4%
20-year CAGR (F20 - F40)	4.7%

9.4 PEAK DEMAND FORCAST UNCERTAINTY BAND

The peak demand forecast reflects the combination of a number of customer sector forecasts and their associated input and modelling uncertainties. In particular, large industrial sector uncertainties related to potential facility closure, facility expansions or new facility developments are included. For the residential and commercial sectors load impacted by temperature, short-term temperature can be highly variable relative to our assumptions of a rolling 30-year average trend of coldest daily average temperature. Over the longer term, projected climate changes related to warmer winters and extreme weather may impact peak demand. Finally, the economic disruptions caused by the COVID-19 pandemic likely impact short-term peak demand patterns and structural changes may impact peak demand patterns over the long term. These uncertainties create risks that peak demand is higher or lower than expected.

There are additional peak modelling uncertainties related to energy-to-peak data relationships.

The peak uncertainty bands for the December 2020 peak forecast were constructed as follows:

- For the transmission loads (i.e., large industrial sector and other transmission voltage customers) and EVs, discrete high and low peak demand forecasts were developed in concert with the discrete high and low energy forecasts. These are described in the section 6 Large Industrial and section 8 Electric Vehicles.
- For the distribution loads (residential, commercial, light industrial), before EV impacts, the high and low peak demand forecasts were developed by using the same high and low uncertainty bands (as a percentage difference relative to the reference forecast)

for the distribution energy forecast before EV impacts. The bands were calculated for each of BC Hydro's four service regions:: Lower Mainland, Vancouver Island, South Interior and North Region.

Forecast assumptions are the same for the other utilities (Fortis BC, New Westminster, Seattle City Lights, Hyder Alaska), The results of the high, reference and low total integrated peak forecasts after rate impacts and DSM are shown in Table 9-5.

Table 9-5 Total Integrated High, Reference, and Low Peak Demand Forecasts After Adjustments

Fiscal Year	High Forecast (GWh)	Reference Forecast (GWh)	Low Forecast (GWh)
Actual			
F2020	10,471	10,471	10,471
Forecast			
F2021	10,799	10,405	10,163
F2022	11,182	10,684	10,049
F2023	11,571	10,887	10,023
F2024	11,867	11,041	10,011
F2025	12,260	11,173	9,983
F2026	12,592	11,307	9,945
F2027	13,119	11,439	9,907
F2028	13,402	11,557	9,880
F2029	13,918	11,660	9,780
F2030	14,156	11,768	9,760
F2031	14,399	11,881	9,743
F2032	14,645	12,018	9,726
F2033	14,902	12,152	9,724
F2034	15,159	12,288	9,712
F2035	15,442	12,433	9,702
F2036	15,740	12,589	9,689
F2037	16,032	12,743	9,688
F2038	16,316	12,898	9,685
F2039	16,591	13,053	9,686
F2040	16,853	13,204	9,680
F2041	17,127	13,376	9,704
Compound Annual Growth Rates			
5-year CAGR (F20 - F25)	3.2%	1.3%	(0.9%)
10-year CAGR (F20 - F30)	6.2%	2.4%	(1.4%)
20-year CAGR (F20 - F40)	10.0%	4.7%	(1.6%)

10.0 Non-Integrated Areas and Other Utilities Forecasts

This section is divided into two main parts: (i) Non–Integrated Areas and (ii) sales from BC Hydro to other utilities. We begin with describing the Non-Integrated Area sales followed by sales to other utilities. In both sections we describe the methodology and then the forecasts results.

10.1 NON-INTEGRATED AREAS

10.1.1 NIA Description

The non-integrated areas (NIA) consist of several small communities located in parts of B.C. not connected to BC Hydro's integrated transmission grid. The communities of our NIA include:

- Customers in the Purchase Areas in the South Interior. The Purchase Areas consists of the following six locations: Lardeau, Shutty Bench, Crowsnest, Newgate, Kingsgate-Yahk, and Kelly Lake. To serve customers in the Purchase Areas, BC Hydro purchases electricity from several neighbouring electric utilities,
- Customers in Zone II communities in the North Region and Vancouver Island. Zone II NIA customers include 15 communities from the following locations:[10] Masset, Sandspit, Atlin, Dease Lake, Telegraph Creek, Anahim Lake, Bella Coola, Hartley Bay, Good Hope Lake, Toad River, Jade City, Fort Ware, Kwdacha, and Tsay Keh Dene,
- Customers in Zone 1B community of Bella Bella in the North Region, and
- Customers in the Northern Rockies Regional Municipality (Fort Nelson area) in the North Region.

As of fiscal 2020, total gross requirements for the entire NIA were 303 GWh, where more than half of this amount is in the Fort Nelson area.

10.1.2 NIA Forecast Methodology

Various methodologies are used to develop the forecast for communities that make up the NIA areas. The methodologies range from trend analysis, developing specific customer load forecasts, and regression models. All of the forecasts developed from these methods are supplemented with information from local community members about future loads. BC Hydro's Distribution Area planners, which look after planning distribution station assets within the NIA, gather information from local connection offices and communities about load increase or decrease for the NIA.

For the Purchase Areas, the forecast is developed by a trend analysis of the historical total gross requirements of the communities that makes up the Purchase Areas.

For Zone II and Zone 1B communities, the forecasts are developed using a trend analysis of the historical loads that make up major sectors in these areas. A trend analysis is carried out for the residential sector, commercial and light industrial sector and other loads such as street light customers, irrigation customers and BC Hydro own use. The trend analysis establishes a base load forecast which is supplemented by other forecast information on individual projects or customers loads. This additional load information is obtained from customer service requests via local BC Hydro personal or identified by our Distribution Area planners. These load additions tend to be the main drivers of load growth within all of these communities.

For Fort Nelson area sales, the forecast is developed as the sum of the forecast for each of the major customer sectors including residential, commercial and light industrial and a large industrial sector, which consists of two major loads which are deriv ed as follows:

- The forecast for the residential sector is the product of the accounts and the average use per account. The account projection and the average use per account projection are based on a trend analysis of historical billing data. A trend analysis is used bec ause there is not enough resolution (i.e. detail in our residential end use survey) to develop a statistically sound SAE model for the residential and commercial load in communities that make up the NIA areas.
- The forecast for the commercial and light industrial sector is developed with a regress ion model involving historical sales and employment where the history and forecast of employment comes from CBoC Economic Forecast. The forecast for the wood product segment which consists of two mills, currently shutdown, is developed on an account by acc ount basis.
- The forecast for the two large industrial customers in the Fort Nelson area are also developed on an account by account basis using the same methodology that applies to other oil and gas loads connected to the integrated grid.
- The forecasts for street lighting customers, irrigation customers and BC Hydro own use within the Fort Nelson area is developed based on a trend analysis.

The NIA Load Forecast is the result of an aggregation of our load forecasting analysis (i.e., trends, customer proje ctions, and regression models, and load additions as requests for service) for all parts of the NIA listed above, less load reductions fo r rate impacts and load reductions for savings from our DSM plan.

Rate impacts are developed in the same manner as they are developed for the main customer sectors described in this document. Savings from our DSM t plan identified for the NIA area are allocated to each of the four main parts that make up the NIA on an historical sales percentage basis. An allocation of th e DSM savings is used because it is not exactly known which individual part of the NIA will engage in DSM activities.

10.1.3 NIA Forecast Results

The Non-Integrated Area Load Forecast results are shown in Table 10-1.

For the most part, the loads that make up the NIA are stable, and the forecasts indicate a slow increase much like the historical trend. The largest growth is anticipated to occur in the Fort Nelson area over the period of fiscal 2021 to fiscal 2022. During this period, it is expected that there will be an increase in the demand for electricity by the wood product segment.

Table 10-1 – NIA Total Gross Requirements Sales History and Forecast After Adjustments

Fiscal year	Purchase Area Load Forecast (GWh)	Zone II and Zone 1B Load Forecast (GWh)	Fort Nelson Load Forecast (GWh)	Total NIA Load Forecast (GWh)
Actual				
F2015	12	112	204	329
F2016	11	112	205	328
F2017	13	116	198	328
F2018	14	115	185	315
F2019	13	113	184	311
F2020	13	115	176	303
Forecast				
F2021	13	116	150	279
F2022	13	118	162	293
F2023	13	119	180	312
F2024	14	120	208	342
F2025	14	120	210	343
F2026	14	120	213	347
F2027	14	120	215	350
F2028	14	120	215	349
F2029	15	120	215	350
F2030	15	120	215	350
F2031	15	121	215	351
F2032	15	121	215	351
F2033	15	122	215	352
F2034	16	122	215	352
F2035	16	123	215	353
F2036	16	123	215	354
F2037	16	124	215	355
F2038	17	125	215	356
F2039	17	125	215	357
F2040	17	126	215	358
F2041	17	127	215	359
Compound Annual Growth Rates				
5-year History CAGR (F15 - F20)	0.5%	0.5%	(3.0%)	(1.6%)
5-year CAGR (F20 - F25)	1.7%	0.8%	3.6%	2.5%
10-year CAGR (F20 - F30)	1.6%	0.4%	2.0%	1.4%
20-year CAGR (F20 - F40)	1.5%	0.5%	1.0%	0.8%

For the most part, the loads that make up the NIA are stable and the forecasts indicate a slow increase much like the histori cal trend. Similar to the other sectors, we anticipated a decrease in energy demand for fiscal 2021 due to the pandemic. However, the largest growth is anticipated to occur in the Fort Nelson area over the period of fiscal 2023 to fiscal 2024. During this period it is expected that there will be an increase in the demand for electricity from the wood product and oil and gas sectors.

10.1.4 NIA Forecast Uncertainties

There are two main uncertainties to the NIA forecast. First is the impact of COVID-19 and second are the discrete events such as the opening or closing of operations. In some instances, the exact timing of when these p rojects are expected to transpire are difficult to predict as major developments, such as large residential or commercial projects, with in the smaller communities often require external funding. Our BC Hydro planners, NIA station managers and other personal with BC Hydro keep in contact with various communities to gather information on the types of future loads and when future loads are expected come online.

Some of the loads in the Fort Nelson area are dependent upon the future development of the resource sector. These loads can vary from the forecast due to changes in external market conditions such as fluctuations in natural gas prices and wood segment prices.

10.2 OTHER UTILITIES

The other utilities served by BC Hydro are listed below:

- City of New Westminster, located within BC Hydro's Lower Mainland Region,
- FortisBC Electric, located in southeastern B.C.,
- Seattle City Light, located in the state of Washington, USA, and
- Hyder, Alaska, located in Alaska, USA.

Hyder is served at distribution voltage while the other three utilities are served at transmission voltage.

All of these utilities have formal arrangements with BC Hydro for electrical service. In fiscal 2020, annual energy sales to City of New Westminster, FortisBC Electric, Seattle City Light, and Hyder were 464 GWh, 585 GWh, 312 GWh, and 1 GWh, respectively. Firm exports include Seattle City Light and Hyder, while sales to inter-utilities include City of New Westminster and FortisBC Electric.

10.2.1 Other Utilities Forecast Methodology

The forecast methodology varies by utility, as follows:

The forecast for the City of New Westminster is based on trend analysis and information from BC Hydro's distribution planners on new larger projects that have requested electricity service.

The forecast of sales to FortisBC Electric is based on a modelled comparison of the relative cost of purchasing electricity from BC Hydro (including future rate increases) applied to Rate Schedule 3808 versus the cost of market purchases. The model also considers information provided by FortisBC Electric on its expected purchase of electricity from BC Hydro. Since the forecasting model determines the forecast of sales to FortisBC Electric by the relative costs of purchases (i.e., market vs BC Hydro rates) it already accounts for the impact future changes in our electricity rates. As such, there is no need to apply a further rate impact to the results of the model.

The forecast for Seattle City Light is prescribed within a treaty between British Columbia and Seattle dated March 30, 1984 and which expires on January 1, 2066.

The sales forecast for Hyder, Alaska is based on a trend analysis.

10.2.2 Other Utilities Forecast Results

Table 10-2 shows the other utilities forecast with rate impacts.

Table 10-2 – December 2020 Other Utilities Sales History and Forecast After Rate Impacts

Fiscal Year	City of New Westminster (GWh)	FortisBC Electric (GWh)	Seattle City Light (GWh)	Hyder, Alaska (GWh)	Total Other Utilities (GWh)
Actual					
F2015	444	522	305	0.9	1,272
F2016	455	516	308	0.9	1,280
F2017	463	589	325	0.9	1,378
F2018	465	551	318	0.8	1,336
F2019	462	435	315	0.7	1,212
F2020	464	585	312	0.7	1,362
Forecast					
F2021	506	718	310	0.9	1,534
F2022	507	622	312	1.0	1,442
F2023	505	618	310	1.0	1,435
F2024	511	615	310	1.0	1,438
F2025	515	637	310	1.0	1,464
F2026	521	627	312	1.0	1,460
F2027	526	709	310	1.0	1,546
F2028	532	720	310	1.0	1,563
F2029	537	750	310	1.0	1,598
F2030	542	771	312	1.0	1,627
F2031	548	815	310	1.0	1,675
F2032	554	844	310	1.0	1,709
F2033	559	872	310	1.0	1,743
F2034	565	903	312	1.0	1,781
F2035	571	940	310	1.0	1,823
F2036	578	965	310	1.0	1,854
F2037	584	969	310	1.0	1,864
F2038	590	974	312	1.0	1,877
F2039	596	970	310	1.0	1,878
F2040	604	970	310	1.0	1,885
F2041	610	995	310	1.0	1,916
Compound Annual Growth Rates					
5-year History CAGR (F15 - F20)	0.9%	2.3%	0.4%	(4.3%)	1.4%
5-year CAGR (F20 - F25)	2.1%	1.7%	(0.1%)	6.7%	1.5%
10-year CAGR (F20 - F30)	1.6%	2.8%	0.0%	3.3%	1.8%
20-year CAGR (F20 - F40)	1.3%	2.6%	(0.0%)	1.6%	1.6%

Electricity sales to the City of New Westminster are forecast to grow about 2.1 per cent over the next five years. Sales to FortisBC Electric are forecast at an annual compound growth rate of 1.7 per cent over the next five years. Both Seattle City Light and Hyder Alaska are forecast to have little growth in load supplied by BC Hydro.

10.2.3 Other Utility Forecast Risks and Uncertainties

The main risk to the forecast of electricity sales to the City of New Westminster is a discrete event such as a further large new load addition. The risks to the forecast of sales to FortisBC Electric would be unforeseen changes in the market conditions which may impact how that utility plans to meet its supply arrangements.

Given that the forecast for Seattle City Light is based on a signed treaty, there is minimal sales risk over the entire forecast period. The sales risk for Hyder is also minimal given that its load is so small.

11.0 Glossary

Accrued Sales are an estimate of electricity delivered within a specific month. Most customer meters are not read at every month-end, so the amount of electricity delivered in a month is not known precisely. In accordance with GAAP, monthly accrued sales are used for monthly financial reporting.

Back-casting Estimating econometric or other models over a historical time period and comparing the predictions of the models to actual results over the same time period.

Billed Sales The amount of electricity billed. Because bills are produced after the electricity has been delivered, monthly billed sales lag monthly delivery of electricity.

Binary Variable is a variable whose value is either zero or one. Binary variables are often used as independent variables in regression models in order to account for events that either occur or do not occur. In this latter context, binary variables are often referred to as "dummy variables" in regression.

Calibration Estimating econometric or other models over a historical time period.

Coincidence Factor A ratio reflecting the relative magnitude of a region's (or customer's or group of customers') demand at the time of the system's maximum peak demand to the region's (or customer's or group of customers') maximum peak demand.

Commercial Output Commercial output focuses on the provisions of services in the economy and so includes such things as public administration, insurance agents, bankers, wholesale and retail trade, food services, accommodation provisions etc.

Consumer Price Index (CPI) An inflation index calculated by comparing the price of a typical bundle of goods in the year in question to the price of the same goods in a set reference year.

Cooling Degree Day (CDD) is a measure of warmness, defined by the number of degrees above a certain daily average temperature measured in Degrees Celsius CDDs are drivers of utility air-conditioning electricity loads.

Demand-Side Management (DSM) Activities that occur on the demand side of the revenue meter and are influenced by the utility. Demand-Side Management activities result in a change in electricity sales. Past Demand-Side Management savings include incremental load displacement and energy efficiency savings. Note that BC Hydro's historical sales include the impact of Demand-Side Management savings realized up to that year.

Design Temperature Rolling average of the coldest daily average temperature over the most recent 30 years

Distribution Voltage Customer A BC Hydro customer who receives electricity via distribution lines that operates at lower voltages (60 kV and less).

Domestic System Peak includes the peak requirements for BC Hydro's distribution and transmission customers in its service territory; sales to the City of New Westminster and system transmission and distribution losses.

Econometric Modelling The use of statistical techniques, typically regression analysis of time-series and/or cross-sectional data, to detect statistically verifiable relationships, coherent with economic theory, between an explained variable (e.g. electricity consumption) and explanatory variables (e.g. industry output, prices of alternative energy inputs and GDP).

Elasticity The proportionate change in a dependent variable (e.g. electricity consumption) divided by the proportionate change in a specified independent variable (e.g. electricity price). A dependent variable is highly elastic with respect to a given independent variable if the calculated elasticity is much greater than one. The dependent variable is inelastic if the elasticity is less than one.

End-use Model A model used to analyze and forecast energy demand, which focuses on the end uses or services provided by energy. Typical end uses are lighting, process heat and motor drive. For a given industry, the model estimates the influence of prices and technological change on the evolution of the secondary energy inputs required to satisfy the industry's end uses over time.

Energy The amount of electricity delivered or consumed over a certain time period, measured in multiples of watt-hours. A 100-watt bulb consumes 200 watt-hours in two hours.

Energy Efficiency Is the ratio of the energy service delivered from a process or piece of equipment to the energy input. Energy efficiency is a dimensionless number, with a value between 0 and 1 or, when multiplied by 100, is given as a percentage.

EV Electric Vehicle

Fuel Switching is specific to the December 2020 forecast as presented in this report. Fuel switching means switching from one kind of energy source or use to another that decreases GHG emissions in B.C., and the estimated fuel switching load included in the March 2020 forecast is based on specific government or BC Hydro programs that incent customers to switch from fossil fuel-based energy to clean electricity.

GAAP Generally Accepted Accounting Principles

Gigawatt-hour (GWh) A measure of electrical energy, equivalent to one million kilowatt-hours. (See Units of Measure)

Gross Domestic Product (GDP) A measure of the total flow of goods and services produced by the economy over a specified time period, normally a year or quarter. It is obtained by valuing outputs of goods and services at market prices (alternatively at factor cost), and then aggregating the total of all goods and services.

Heating Degree Day (HDD) Is a measure of coldness, defined by the number of degrees below a certain daily average temperature measured in Degrees Celsius. HDDs are drivers of utility space heating electricity loads.

Integrated System That portion of the BC Hydro's electricity system which is connected as one whole by a high voltage transmission grid.

Integrated System Peak includes the peak requirements for BC Hydro's distribution and transmission customers in its service territory; sales to Other Utilities, which includes Seattle City Light, New Westminster, FortisBC and Hyder Alaska (Tongass Power and Light Co. Inc.); and system transmission and distribution losses.

Intensity A unitized measure of energy consumption, typically in kilowatt-hours per unit of stock. For example, intensity is kWh per account in the residential sector or kWh per unit of production in the industrial sector.

Kilowatt (kW) A kW is 1000 watts and a watt is measure of power that can be transferred instantaneously

Kilowatt-hour (kWh) A measure of electrical energy over a period of time, equivalent to the energy consumed by a 100-watt bulb in 10 hours. (See Units of Measure)

Liquefied Natural Gas (LNG) is natural gas that has been converted temporarily to liquid form for ease of storage or transport. This process involves refrigeration, and requires no chemical transformations.

Load The total amount of electrical power demanded by the utility's customers at any given time, typically measured in megawatts.

Load Displacement Projects that involve the installation of self-generation facilities at customer sites, with the electricity generated being used on-site by the customer, with a resultant decrease in the purchase of electricity from BC Hydro.

Megawatt (MW) A unit used to measure the capacity or potential to generate or consume electricity. One MW equals one million watts. (See Units of Measure)

Megawatt-hour (MWh) A measure of electrical energy, equivalent to 1,000 kWh. (See Units of Measure)

Monte Carlo Method A technique for estimating probabilities involving the construction of a model and the simulation of the outcome of an activity a large number of times. Random sampling techniques are used to generate a range of outcomes. Probabilities are estimated from an analysis of this range of outcomes.

Megavolt-Amps (MVA) – a unit of apparent power, which is real power in MW, divided by power factor.

Natural conservation The increase in energy efficiency that would occur in the absence of any utility-induced Demand-Side Management program, all other things being equal.

Non-coincident In general is the magnitude of a region’s (or customer’s or group of customers’) demand at the time of its peak.

Non-Integrated Areas (NIA) Non-integrated facilities refer to generating facilities that are not connected to the system, located in remote areas of the province

Normalization The correction of actual customer sales and peak demand for factors such as unusually warm or cold weather.

Ordinary Least Squares (OLS) is a method of estimating parameters to minimize the sum of squares errors in a regression model.

Price Elasticity of Demand The percentage change in quantity demanded, divided by the percentage change in price that caused the change in quantity demanded.

Real Price Increases that have been adjusted for changes in prices of all goods. The nominal price of an item may rise by 10 per cent over a year, but inflation (and assumed wages) may have risen by 7% over the same time period. Therefore the effective price increase faced by the consumer is close to 3 per cent. It is necessary to deflate current prices by an appropriate inflation index (the CPI in Canada) to convert money values to constant prices or real terms.

Region A geographical sub-division of the BC Hydro service area used for Load Forecast purposes. Four regions exist: Lower Mainland, Vancouver Island, South Interior and the Northern Region.

Stock A quantity representing a number of energy consuming units. For example, in the residential sector, stock is the number of accounts or housing units; in the commercial sector, stock is represented by the floor area of commercial building space.

System Coincident Peak Demand The greatest combined demand of all BC Hydro customers faced by the generation system during a given fiscal year.

Transmission Voltage Customer A BC Hydro customer that is supplied its electricity via high-voltage transmission lines (60 kV or above).

Trinary variable is another type of binary variable that accounts for instances where sales or use per account in one moth is observed to be shifted from one month to the other.

Units of Measure The large amounts of electricity generated and consumed on a system-wide basis are discussed in multiples of the basic units of watt and watt-hours. Kilowatts and megawatts are used to measure power, and kilowatt-hours, megawatt-hours, and gigawatt-hours are used to measure energy. The equivalence is:

1 kilowatt (kW)	= 1,000 watts
1 megawatt (MW)	= 1,000 kilowatts or 1 million watts
1 kilowatt-hour (kWh)	= 1,000 watt-hours
1 megawatt-hour (MWh)	= 1,000 kilowatt-hours or 1 million watt-hours

1 gigawatt-hour (GWh)	= 1,000 megawatt-hours or 1 billion watt-hours

12.0 Overview of Appendices

The appendices cover additional elements of the December 2020 Load Forecast.

A. DECEMBER 2020 VS. MARCH 2020 LOAD FORECAST AND COVID-19 SCENARIOS

Provides a comparison of December 2020 Load Forecast to the previous forecast/scenarios.

B. SAE EQUATIONS AND FORECASTING MODELS

Provides an explanation of the general framework and equations of the SAE model.

C. TEMPERATURE NORMALIZATION PROCESS

Includes a description of our temperature normalization process for the residential and commercial sectors.

D. PEAK DEMAND FORECAST METHODOLOGY

Provides additional information on the peak forecast methodology.

E. CONFERENCE BOARD OF CANADA 2020 ECONOMIC OUTLOOK

A copy of the Conference Board of Canada's 2020 Economic Outlook report.

F. NAVIUS REPORT

A copy of the Navius report on the accelerated electrification scenario.

G. DECEMBER 2020 LOAD FORECAST TABLES

Tables showing the December 2020 reference load forecast before and after adjustments.

Appendix A: December 2020 vs. March 2020 Load Forecast and COVID-19 Scenarios

BC Hydro prepared a comprehensive 20 year load forecast (the March 2020 Load Forecast) over the winter of 2019 and spring of 2020. The March 2020 Load Forecast was completed prior to the onset of impacts associated with the COVID 19 pandemic. To address those potential impacts, BC Hydro developed two scenarios in April 2020 that were used to inform decisions based on two potential outcomes. The sales projection for fiscal 2022 from one of those scenarios (referred to as “Scenario A”) was used in the calculation of the revenue requirements in the Fiscal 2022 Revenue Requirements Application.

Table A-1 below compares the December 2020 Reference Load Forecast with the March 2020 (pre-COVID) Reference Load Forecast and the two COVID-19 scenarios.

Table A-1 – Total Firm Sales Forecast After Adjustments for Rate Impacts, DSM, and VVO

	December 2020 Reference	March 2020 Reference	COVID-19 Scenario A	COVID-19 Scenario B	December 2020 - March 2020	December 2020 - COVID-19 Scenario A	December 2020 - COVID-19 Scenario B	December 2020 vs March 2020	December 2020 vs COVIDvs19 Scenario A	December 2020 vs COVIDvs19 Scenario B
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(%)	(%)	(%)
F2020 Actual	51,891	51,891	51,891	51,891						
F2021	51,159	53,778	50,574	47,151	(2,619)	3,204	3,422	(4.9%)	1.2%	8.5%
F2022	52,459	54,182	52,600	47,059	(1,724)	1,582	5,541	(3.2%)	(0.3%)	11.5%
F2023	53,562	54,718	53,372	49,917	(1,156)	1,346	3,455	(2.1%)	0.4%	7.3%
F2024	54,509	55,647	54,857	54,857	(1,137)	790	0	(2.0%)	(0.6%)	(0.6%)
F2025	55,532	57,374	56,584	56,584	(1,842)	790	0	(3.2%)	(1.9%)	(1.9%)
F2026	56,630	58,140	57,351	57,351	(1,510)	790	0	(2.6%)	(1.3%)	(1.3%)
F2027	57,373	59,104	58,314	58,314	(1,731)	790	0	(2.9%)	(1.6%)	(1.6%)
F2028	58,117	59,722	58,932	58,932	(1,605)	790	0	(2.7%)	(1.4%)	(1.4%)
F2029	58,434	60,148	59,359	59,359	(1,715)	790	0	(2.9%)	(1.6%)	(1.6%)
F2030	58,797	60,524	59,734	59,734	(1,727)	790	0	(2.9%)	(1.6%)	(1.6%)
F2031	59,185	61,062	60,272	60,272	(1,877)	790	0	(3.1%)	(1.8%)	(1.8%)
F2032	59,696	61,502	60,712	60,712	(1,806)	790	0	(2.9%)	(1.7%)	(1.7%)
F2033	60,073	61,963	61,173	61,173	(1,890)	790	0	(3.0%)	(1.8%)	(1.8%)
F2034	60,523	62,442	61,652	61,652	(1,918)	790	0	(3.1%)	(1.8%)	(1.8%)
F2035	60,997	62,932	62,143	62,143	(1,935)	790	0	(3.1%)	(1.8%)	(1.8%)
F2036	61,520	63,425	62,635	62,635	(1,905)	790	0	(3.0%)	(1.8%)	(1.8%)
F2037	61,939	63,899	63,109	63,109	(1,960)	790	0	(3.1%)	(1.9%)	(1.9%)
F2038	62,430	64,403	63,613	63,613	(1,973)	790	0	(3.1%)	(1.9%)	(1.9%)
F2039	62,914	64,877	64,088	64,088	(1,964)	790	0	(3.0%)	(1.8%)	(1.8%)
F2040	63,450	65,374	64,585	64,585	(1,925)	790	0	(2.9%)	(1.8%)	(1.8%)
F2041	64,151									
20-yr Compound Annual Growth Rate F20-F40	1.0%	1.2%	1.1%	1.1%						

The 20-year compound annual growth rate from Fiscal 2020 to Fiscal 2040 for the December Load Forecast is 1.1%, which is slightly lower than the previous forecasts, primarily due to revised outlooks for the commercial and large industrial sectors, which include updated information on expected impacts of and recovery from the COVID-19 pandemic.

Appendix B: SAE Equations and Forecasting Models

12.1 INTRODUCTION

Our unadjusted sales forecasts[11] for residential and commercial sectors are based on:

- the estimated coefficients of the SAE, and
- the forecasts of economic data, temperature data, average efficiency data and saturation data. All of these are included in the SAE models.

Section A1.2 below covers the general framework of the SAE model, the development of its main variables (i.e., Heating, Cooling and Other) and the equations for these variables.

12.2 STATISTICALLY ADJUSTED END USE FRAMEWORK

The description of the SAE framework described below for the residential sector generally applies to the commercial sector. The main difference between the residential and commercial framework is that the dependent variable in the residential framework is th e average use per account and the dependent variable in commercial framework is commercial sales.

The statistically adjusted end-use modeling framework begins by defining the dependent variable: the average electricity use per account (Use_m) in a month (m) as the sum of the average electricity use by per account from heating equipment ($Heat_m$), cooling equipment ($Cool_m$), and other equipment ($Other_m$). Formally, this is written as:

Equation B.1

$$USE_m = Heat_m + Cool_m + Other_m$$

Equation B.1 can be written in the format of a linear regression model as:

Equation B.2

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m$$

Where: USE_m is the dependent variable of the above regression model or average use per account (monthly). The independent variables in the regression model are $XHeat_m$, $XCool_m$, and $XOther_m$. These are the main explanatory variables, which are constructed monthly (m) from end-use information, economic drivers, and temperature data. The parameter ε_m represents the random error term in the above regression model. The parameters b_1, b_2, and b_3 are the coefficients of the regression model which represent the relative contribution of the main explanatory variables (i.e., major end uses) to the average residential use per account.

The equations below show the construction of the main independent variables. For each variable there is data in the historical period (i.e., estimation period) and data in the forecast period. The estimated coefficients of the model and the forecast data fo r each main variable determine the results (i.e., forecast of average use per account) that come from the SAE model.

[11] In this Appendix as well all the other sections and appendices contained in this report, the term “unadjusted forecast” and the “term model projections” are used interchangeably.

XHeat represents average heating use per account. The amount of electricity used per account for heating depends on the following types of variables:

- heating degree days (temperature),
- heating equipment saturation levels (percentage of accounts that have a certain type of heating equipment),
- average efficiency of heating equipment,
- average number of days in the billing cycle for each month, and
- economic variables. For the residential sector this includes people per account and real personal disposable income. For the commercial sector this includes employment, real retail sales, and real commercial GDP.

The heating variable $XHeat_m$ is a product of a monthly equipment index and a monthly usage multiplier. In equation form this is expressed as:

Equation B.3

$$XHeat_m = HeatIndex_m \times HeatUse_m$$

Where: $\mathrm{XHeat_m}$ is the average heating use per account in a month (m). This variable is a product of two monthly index variables: (i) $\mathrm{HeatIndex_m}$ is the aggregate amount of heating use per account in a month for the various types of heating equipment; and (ii) $\mathrm{HeatUse_m}$ is monthly index of heating usage.

The sub-equation for $HeatIndex_m$ in equation B.3 is:

Equation B.3.1

$$HeatIndex_m = \sum_{SpaceHeating} EndUseEnergy_{e,BaseYear} \times \frac{\left(Share_m / Eff_m\right)}{\left(Share_{BaseYear} / Eff_{BaseYear}\right)}$$

Where: End Use Energy is the average use per account for each type of heating equipment, e refers to the different categories of space heating, BaseYear represents the base year for the SAE model, Share mean saturation levels [12] of the different types of heating equipment which comes from our Residential End Use Survey data (REUS), Eff is the average effi ciency of the different types of space heating equipment.

The heating equipment index (i.e., HeatIndex) depends on heating equipment saturation levels normalized (i.e., divided) by average efficiency level. As a result, the heating index will increase over time if there are changes in heating equipment saturation levels, and will decrease over time if there are improvements in the average equipment efficiencies or the thermal efficiency of residences.

Space heating usage level (i.e., $\mathrm{XHeatUse_m}$) is a function of temperature (Heating Degree Days) and economic factors. The sub-equation for $\mathrm{XHeatUse_m}$ in equation B.3 is:

Equation B.3.2

$$HeatUse_m = \left[\frac{BDays_m}{30.5}\right] \times \left[\frac{WgtHDD_m}{HDD_{BaseYear}}\right] \times \left[\frac{PeoplePerAccount_m}{PeoplePerAccount_{BaseYear}}\right]^{EI1} \times \left[\frac{Income_m}{Income_{BaseYear}}\right]^{EI2}$$

Where: m refers to monthly values, Base Year is the base year of the SAE model, BDays refers to billing days and *EI1 and EI2* are the economic elasticities of average use per account for people per account and real disposable income respectively. Each annual economic variable is converted into a monthly indices which is developed as a 12 month rolling average of the annual economic variable weighted (i.e., divided) by its average monthly value in the base year of the model. The variable $WgtHDD_m$ is the actual

[12] Saturation levels are defined as the percentage of accounts that have a certain type of electrical equipment or appliance.

weighted heating degree days in a month divided by the average monthly heating degree days in the base year of the model. The weights applied to the monthly heating degree days are used to align the actual monthly heating degree days to the billing cycle data on the residential sales over the year. For the forecast period, the variable $WgtHDD_m$ is the 10 year rolling average (i.e., temperature normalized) of heating degree days in each month.

XCool represents the average cooling use per account. This variable is constructed in a similar manner to heating. The amount of electricity use per account for cooling depends on the following types of variables:

- cooling degree days (temperature variable),
- cooling equipment saturation levels (percentages of residential accounts that have a cooling appliance),
- average efficiency of cooling equipment,
- average number of days in the billing cycle for each month, and
- economic variables including people per account and disposable income.

The cooling variable, $XCool_m$, is represented as the product of an equipment-based index and monthly usage multiplier. In equation form this represented as:

Equation B.4

$$XCool_m = CoolIndex_m \times CoolUse_m$$

Where: $XCool_m$ is the average electricity use per account for cooling in a month (m), $CoolIndex_m$ is an index of average cooling equipment use per account in a month (m); and $CoolUse_m$ is the monthly usage multiplier for cooling.

The sub-equations for $CoolIndex_m$ and $CoolUse_m$ are the same equations as those above for heating (i.e., equations B.3.1 and B.3.2) with the exception the last equation B.3.2 includes cooling degree days instead of heating degree days.

As with space heating, the cooling equipment index ($CoolIndex_m$) depends on the cooling equipment saturation levels normalized (i.e., divided) by average efficiency levels. As a result, the cooling index will increase over time if there are changes in cooling equipment saturation levels, and will decrease over time if there are improvements in equipment efficiencies or the thermal efficiency of buildings. Space cooling system usage levels ($CoolUse_m$) are driven on a monthly basis by several factors, including temperature (Cooling Degree Days) and similar economic factors used to develop heating usage.

XOther: represents the average use per account for residential end-uses of electricity that are not temperature sensitive. Some examples of non-temperature sensitive end-uses are lighting, refrigeration, cooking, clothes washing and drying, entertainment equipment (TVs) and other plug in equipment. The average use per account of electricity for other equipment is driven by:

- appliance and equipment saturation levels,
- appliance efficiency levels,
- average number of days in the billing cycle for each month, and
- economic variables.

The explanatory variable $XOther_m$ is defined as:

Equation B.5

$$XOther_m = OtherEqpIndex_m \times OtherUse_m$$

The first term on the right hand side (i.e., $OtherEqpIndex_m$) of the above equation embodies information about the average usage per month of various non-temperature dependent appliances as well as their saturation levels and their average efficiency ratings. The second term ($OtherUse_m$) captures the impact of economic variables of the overall average use of electricity through the use of other non-temperature dependent equipment. These economic variables are the same ones used for explaining heating and cooling use.

The first term has the following sub-equation:

Equation B.5.1

$$Other\ Eqp\ Index_m = Weight^{Type} \times \frac{Sat_m^{Type} / Eff_m}{Sat_m^{Type} / Eff_m} \times MoMult_m^{Type}$$

The weight term is the non-temperature dependent average use per account for specific residential end uses of electricity such as lighting, dishwasher, refrigerators etc. Sat_m^{Type} is the saturation level (i.e., percentage of accounts having at least one of these types of end uses). *Eff* is the average stock efficiency from the EIA of the various non–heating and non-cooling end uses. *MoMult* is a monthly multiplier that shapes the index to our billing data on the average use per account.

The equation for second term on the right hand side of equation B.5 above can be expressed as:

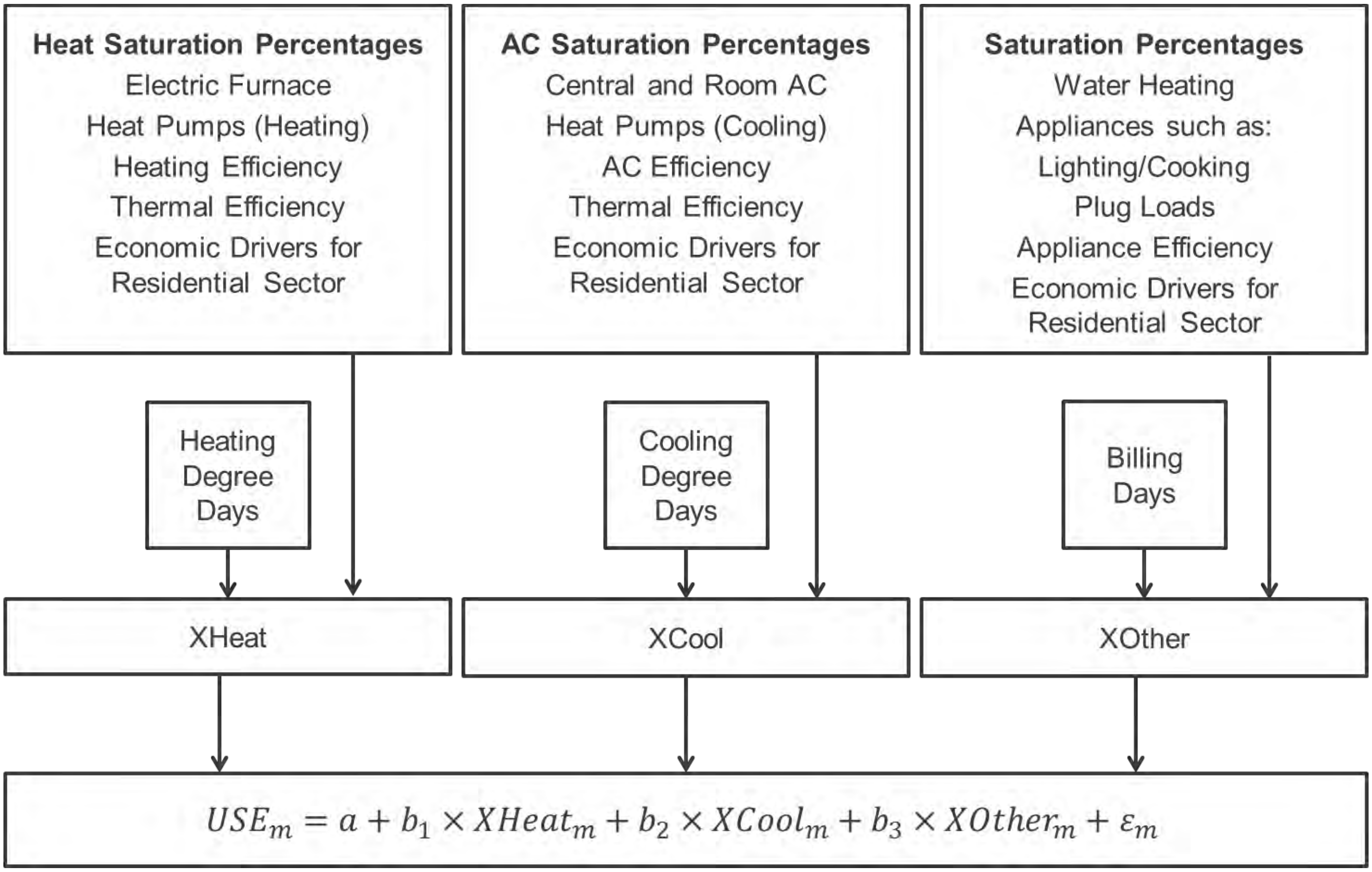
Equation B.5.2

$$Other\ Use_m = \left[\frac{BDays_m}{30.5}\right] \times \left[\frac{PeoplePerAccount}{PeoplePerAccount}\right]^{EI1} \times \left[\frac{Income_m}{Income}\right]^{EI2}$$

Where: $BDays_m$is billing days and *EI1* and EI2 are the economic elasticities of average use per account for people per account and real disposable income respectively.

In summary, Figure 16-1 below shows the inputs used in the construction of the regression variables (i.e. the independent variables) for the residential SAE models. As mentioned above the residential SAE model dependent variable is the average use per account and the commercial SAE model dependent variable is commercial electricity sales. The residential and commercial SAE models also differ in inputs in terms of economic variables, elasticities, and the regional temperatures that determine heating and cooling degree days. The latter of these two variables are discussed in Appendix C below.

Figure 0-1 Statistically Adjusted End Use (SAE) Model



Appendix C: Temperature Normalization Process

12.3 INTRODUCTION - TEMPERATURE NORMALIZATION

As mentioned in Section 5.1 of this report we develop a forecast of the average use per account and residential sales on a temperature normalized basis. We also develop a forecast of commercial sales on a temperature normalized basis. The forecasts for both of these sector forecasts are derived from our SAE models that include various drivers such as our heating and cooling degree day vari ables.

Since the forecasts are developed on a temperature normalized basis, we need to take the actual sales and temperature normalize them (i.e., adjust the historical sales for instances where actual temperature were different than assumed normal) to report variances and determine the accuracy of our forecasts. Temperature normalization is an estimation process because it involves using models and a series of steps to determine what the actual sales would have been if the actual temperatures variables (i.e., heati ng and cooling degree days) were at their normalized values (i.e., which is defined as the 10 year rolling average).

Each month, we temperature normalize the residential use per account and subsequently normalize the sales by multiplying the temperature normalized use per account by the accounts. We also temperature normalize the commercial sales. We currently temperature normalize the commercial sales at the end of the fiscal year using our SAE models. As part of the audit recommendations[13] we are working towards developing models and a process to temperature normalize commercial sales much like the way we normalize the actuals from residential sector, which is described below.

The following sections explain the temperature normalization process for the resi dential and commercial sectors.

12.4 TEMPERATURE NORMALIZATION PROCESSES STANDING APPROACH

Our current temperature normalization process for the residential and commercial sectors is described below. However, we are continuing to review the applicability of the residential approach described below to the commercial sector.

The central equation in determining a temperature normalized actual is:

Equation E.1

$$Temperature\ Normalized\ Actual = Actual + Model\ Projections\ Under\ Normal\ Temperatures - Model\ Projections\ Under\ Actual\ Temperatures$$

Where: Actual is the actual data from our billing system, Model Projections under Normal Temperature is an estimate[14] using our normal assumptions for heating and cooling degree days, and Model Projections under Actual Temperature is an under actual temperatures (i.e., actual heating and cooling degree days). The model projections are developed with an estimation period that does not include any of the forecast years. For example, our normalized residential and commercial results were done with data ending fiscal 2018.

[13] One of the Load Forecast Audit findings was to update our monthly variance report by includi ng temperature normalized commercial monthly sales and comparing those estimates to the forecast on a monthly basis.

[14] Estimate in the context of temperature normalization means predication of average use per account for the residential sector and prediction of sales for the commercial sector.

12.5 RESIDENTIAL TEMPERATURE NORMALIZATION

To temperature normalize the use per account we use equation E.1 above use the in conjunction with model projections from the following regression model (equation E.2) below:

Equation E.2

$$USE_m = \alpha + \beta_1 \times WgtHCDD_m + \beta_2 \times WgtHCDD_m^2 + \beta_3 \times WgtHCDD_m^3 + \varepsilon_m$$

Where: USE_m is monthly average use per account per account for eight segments of residential load we normalize[15], β_1 to β_3 are the coefficients of the above cubic regression model, $WgtHCDD_m$ is a combination of weighted cooling and heating degree days in a month, $WgtHCDD_m^2$ and $WgtHCDD_m^3$ are squared and cubic weighted heating/cooling degree days[16]; and ε_m is the error term. The weights are used to align the combo of heating and cooling degree days to the monthly billing data.

The most recent 36 months of data is used to estimate the regression model as described in the equation E.2 above for each of the eight residential load segments that get normalized. Every month we determine the temperature normalized average use per account and the residential billed sales using the following steps:

1. we estimate the coefficients of the regression model using data from the past 36 months,
2. from estimated coefficients in equation E.2 we determine the model's prediction of the average use per account under actual temperatures for the past 36 months, including the prediction for the last month,
3. from the estimated coefficients in equation E.2 we determine the model's prediction under normal temperature by replacing the actual combined weighted heating and cooling degree days variables with these variables on a normalized basis; and
4. finally, we determine the temperature normalized average use per account for the month we are normalizing using equation E.1 above.

Normalized residential sales are then calculated for each load segment as the normalized average use per account multiplied by the average number of accounts for the segment. The total BC Hydro service area normalized residential sales in any month is equal to the sum of normalized sales for each segment; and the total normalized sales for a year would be sum over the past 12 months.

12.6 COMMERCIAL TEMPERATURE NORMALIZATION

The process for commercial normalization is similar to the four step process outlined above for the residential sector. The main differences to the residential process are: (i) the eight commercial SAE models and the last 10 years of monthly commercial s ales data are used in the normalization process rather than monthly regression models using the past 36 months; (ii) the commercial sales are normalized at the end of year fiscal year using the commercial SAE model; and (iii) the heating and cooling degree variables in the commercial SAE models and the weights of these variables are different compared to the weights in the above residential models because the billing cycle is different for the commercial segments of load compared to the residential sector.

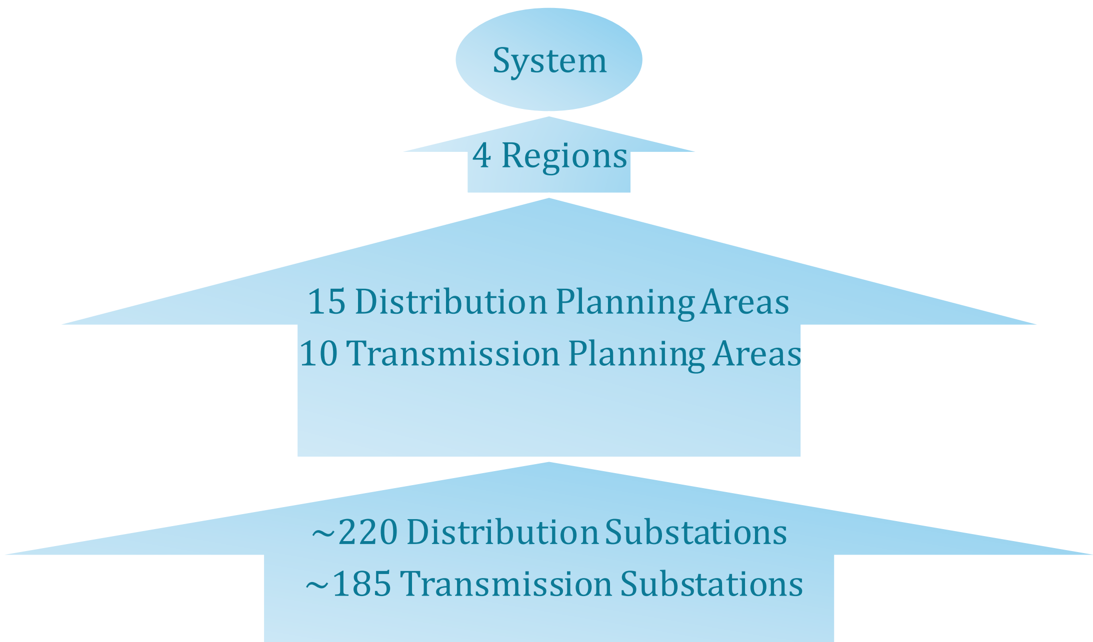
[15] The residential load segments we normalize are the heating and non-heating accounts in each of the four service regions, as such there are eight load segments (2 heating types and 4 regions).

[16] Because billing data of use per account is used in the temperature normalization process, the combined cooling and heating degree-days are weighted as percentages of the current and previous month to match the meter reading cycle for our residential customers. The weighting process is also an element of our SAE model.

Appendix D: Peak Demand Forecast Methodology

Figure D1.1 below shows that the bottom-up peak forecast methodology involves several steps for each of the distribution and transmission peak forecasts. The general description of the development stages in system peak forecast is provided following.

Figure D-1 Peak Demand Forecast Roll-up



The peak demand forecast is built up in three main stages, each incorporating several steps. First stage is the creation of the substation peak in MVA non-coincident[17], second, the four main service region peak forecasts in MW are determined on a region coincident basis and third, the system peak in MW on a system coincident basis.

Stage 1: Distribution Peak Demand Forecast

The distribution peak forecast is built up in three main sub steps:

a) the temperature normalized peak loads by substation/area are developed;

b) the distribution peak forecast guidelines are developed from an econometric model for each planning area;

[17] Non-coincident is defined in the glossary.

c) the guidelines are then used internally for the development of the substation forecast and the distribution peak demand forecast by rolling up to the 4 region level.

The appropriate equations and description of the sub steps are provided below.

(a) Temperature Normalized Substation Peaks

The simplified equation below is the basis for a linear regression model that estimates the relationship between substation peak demand and temperature:

Equation D1.1:

$$\mathrm{KVA} = \alpha + \beta * \mathrm{min}$$

Where:

- KVA is the metered peak load; and
- min is the minimum mean temperature for the coldest day during the metered period.
- α and β are the regression coefficients from a time series regression of peak substation demands on temperatures.

Using the estimated regression coefficients, the temperature - normalized peak is then calculated based on the design day temperature for that substation[18]:

Equation D1.2:

$$\mathrm{NKVA} = \alpha + \beta * \mathrm{designmin}$$

Where:

- NKVA is temperature -normalized peak; and
- designmin is the design temperature for the substation.

The first step involves estimating a relationship between substation peak demand and temperature. This is produced by equation D1.1.

In order to account for year to year variation in temperatures and other impacting factors, the historical substation peak demand data is ‘normalized’ to remove the impact of temperature variation from the mean temperature and, where possible, the impact of day of week,month, holidays, hours of darkness and other factors that may impact the peak demand. To account for temperature response often being non-linear, several models are created and the best fit model is used. Temperature independent factors, such as IPP generation impact are also removed before normalization. This is done through multivariable regression using MetrixND software.

Temperature data is obtained from Environment Canada using weather stations throughout BC to enable correlation between last year’s temperature at peak load and the design temperature (mean of the lowest daily mean temperatures over the past 30 years).

[18] A regression model using non-linear variables was also used for temperature normalization.

Temperature-normalized substation peak for each substation for the previous winter is determined by substituting the actual temperatures with the design temperature. This is depicted in equation D1.2.

(b) Distribution Peak Guideline Forecast

In the section sub step, a distribution substation peak guideline forecast is prepared for 15 planning areas using the following forecasting and (econometric model) equation:

Equation D1.3

$$SK_{it} = [\alpha_1 SFDHTG + \alpha_2 SFDNON + \alpha_3 MULTHTG + \alpha_4 MULNON + \alpha_5 U35E + \alpha_6 O35E]$$

Where:

- SK_{it} is the total substation peak for the i^{th} planning area;
- SFDHTG is the number of single-family electrically heated homes;
- SFDNON is the number of single-family non-electrically heated homes;
- MULTHTG is the number of multi-family electrically heated homes;
- MULTNON is the number of multi-family non-electrically heated homes;
- U35E is annual energy consumption General under 35 kW;
- O35E is annual energy consumption General over 35 kW;
- the coefficients $\alpha 1$, $\alpha 2$, $\alpha 3$, and $\alpha 4$ are kW contribution to the distribution peak per dwelling in area i, for the four dwelling types under normal temperature conditions; and the coefficients, $\alpha 5$ and $\alpha 6$ represent the increase in peak demand due to a one-kWh increase in the General rate class Under 35 and Over 35 kW energy consumption.

c) Substation forecast and distribution peak forecast.

The guideline forecast provides the expected total substation growth from the base year for each planning area. The drivers of the guideline forecast are based on regional economic information such as housing starts and employment. The guideline forecast is provided to BC Hydro Distribution Planners who are using it as a top-down anchor in developing an internal individual substation forecast. The Distribution Planners are taking inputs from the area guidelines provided by the Load Forecasting group and breaking them down to each substation service territory, and, where applicable to each feeder section. During this step, BC Hydro Distribution Planners may have additional and information or revised information from field engineers on expected increases or decreases on discrete customer loads as well as operational requirements for substations. The substation forecast is used for Capital Plan studies. In the past, the substation forecast would be averaged with the guideline forecast in developing the final distribution peak. However, due to the time differences between Load Forecast and Distribution Planning's cycles, only the guideline forecast was used in the development of the December 2020 Peak demand forecast.

The guideline forecast is summed up to the four main regions (Lower Mainland, Vancouver Island, North Region and South Region) on a non-coincident basis in MVA in preparation for the next stage.

Stage 2: Regional Peak Forecast

The regional peak is forecast developed using the following equation:

Equation D1.4:

$$RPKjt = \Sigma j\,[PKit * DCFj * PFj + TPj * TCFj * PFj + OPj * OCFj]$$

Where:

- DCF is the regional distribution peak coincidence factor;
- PF is the regional power factor for distribution and transmission;
- TP is the transmission peak; this is the aggregate of the transmission account peak forecast in each service region.
- TCF is the transmission coincident factor;
- OP is the other utility peak sales;
- OCF is the other utility coincident factor; and
- PK is the weighted average distribution substation forecast

A transmission peak forecast is prepared for each commercial and industrial transmission account using a bottom-up approach as described in section 6.0 Large Industrial Forecast. This involves using the historical peak data, information from Key Account Managers and market information and industry reports.

Stage 3: System Coincident Peak Forecast

Finally, system coincident peak is created as the sum of coincidence-adjusted regional peaks and it includes transmission losses:

Equation D1.4:

$$SPK = (1 + TL) * \Sigma j\, RPKjt * SCFj$$

Where:

- TL is the transmission loss factor; and
- SCF are the system coincidence factors for each of the four regions.

Appendix E: Conference Board of Canada 2020 Economic Outlook

The Conference Board of Canada

B.C Economic Outlook 2020

Presented to:
BC Hydro

Prepared by: Christopher Heschl
The Conference Board of Canada
September 15, 2020

Table of Contents

Introduction

As COVID-19 spread throughout the world in 2020, many countries mandated lockdowns to slow the transmission of the disease. As a result, economic activity around the globe ground to a halt, and Canada was no different. In the second half of March, provincial governments across the country began implementing emergency measures, such as physical distancing, to slow the spread of COVID-19, with many non-essential businesses ordered to close. Even though the measures were not in place until the second half of March, they had a devasting impact on the economy. Nationally, real gross domestic product (GDP) fell 7.5 per cent month over month in March, followed by an even greater drop of close to 12.0 per cent in April.[1]

The good news is that the gradual easing of restrictions since April has allowed the economy to rebound, though the recovery is expected to be gradual. After losing more than 3 million jobs between February and April, Canada has regained 1.66 million of those jobs as of July. This momentum is expected to continue into the fall as provinces carry out their reopening processes, easing social distancing requirements and allowing business, including dine-in restaurants, bars, gyms, and retail stores, to remain open. The success of these reopening plans and the country's ability to avoid a second wave will be crucial to the economy's recovery over the medium term. However, the need for people to continue to practice social distancing will keep many parts of the economy operating below potential until COVID-19 is no longer a domestic public health threat and a vaccine is available.

In this briefing, we examine the potential impact of the COVID-19 pandemic on the Vancouver census metropolitan area's (CMA)[2] economy from 2020 to 2040 to help inform BC Hydro's long-term projections of electricity usage in British Columbia. In the past, the Conference Board has provided BC Hydro with long-term economic forecasts for BC as a whole and for various sub-provincial regions. However, those past forecasts took months to complete, and due to the abrupt and significant negative impact of COVID-19 on Canada's economy in the first half of 2020, it was important to produce an informative forecast in a shorter period of time. The Vancouver model was used for this project because it is smaller than the BC model and can, therefore, produce outputs at a faster pace. More importantly, Vancouver accounts for the majority of economic activity in the province. In 2019, Vancouver's economy generated 60.5 per cent of BC's GDP, making the region's performance a good indicator of economic activity in the province overall.

[1] The Conference Board of Canada, "Uneven Recovery: Provincial Outlook," 3.
[2] The Vancouver CMA is composed of the City of Vancouver and surrounding municipalities, towns, townships, and Indian reserves as defined by Statistics Canada here. In this briefing, any mention of "Vancouver" refers to the "Vancouver CMA."

Methodology and Approach

The Conference Board has developed and refined a methodology to estimate economic activity at the CMA level, which has been used for this project to create long-term forecasts of key economic variables for the Vancouver CMA. Specifically, annual projections extending from 2020 to 2040 were provided for the following variables: total real GDP, total employment, total population, single housing starts, multiple housing starts, and total housing stock. Annual projections for employment by industry at the two-digit North American Industry Classification System (NAICS) was also provided, but only from 2020 to 2024.

The economic data used to inform the forecasts came largely from Statistics Canada and Canada Mortgage and Housing Corporation (CMHC). Projections for total employment and employment by industry are based on Statistics Canada's monthly Labour Force Survey results for the Vancouver CMA. Total population projections for Vancouver are based on demographic data released annually from Statistics Canada. Single and multiple-unit housing starts projections are based on data available from CMHC on a monthly basis. Total housing stock estimates are based on housing data from the 2016 Census available from Statistics Canada and housing completions data available from CMHC. Finally, real GDP forecasts for Vancouver were estimated using the Conference Board's own methodology, as historical GDP data at the CMA level is not available from any official source.

The Conference Board's Vancouver CMA model is typically used to create five-year economic forecasts on a quarterly basis. For example, in 2020 the model is designed to project economic variables over the period 2020-2024. To extend the forecast to 2040, we used the Conference Board's BC and Canada long-term forecasts as a guide. Because the most recent BC long-term forecast was published in December 2019, the Vancouver forecasts presented in this briefing are more in line with the Canada long-term forecast published in June 2020 that incorporates the impacts of COVID-19 on the national economy.

Conducting economic forecasts during the time of COVID-19 is a challenging exercise due to significant uncertainties. Because the economy is expected to operate below capacity until social distancing measures are no longer required, the economy is not anticipated to recover fully until COVID-19 is no longer a public health risk. As such, the speed of Vancouver's economic recovery is dependent on the development and availability of an effective COVID-19 vaccine or treatment. Other factors that could prolong the recovery include persistently low consumer and business confidence limiting consumption and investment, respectively, as well as slower international in-migration due to border closures and weaker economic prospects.

To accommodate for the uncertainty involved in forecasting the impact of COVID-19 on Vancouver's economy, we created three different scenarios and produced a forecast for each one based on different assumptions. The first scenario—the baseline case—is based on the assumptions used to conduct the Conference Board's June 2020 Canada forecast and presents a balanced expectation of Vancouver's economic performance. The second scenario—the high case—is based on the Conference Board's April 2020 Vancouver forecast and presents more optimistic assumptions and a much faster recovery than in the baseline scenario. Finally, the third scenario—the low case—presents a much slower recovery compared to the baseline scenario. For each scenario, the assumptions and results are presented in the next section, while detailed assumptions around the recovery path for employment by industry at the two-digit NAICS level is included in the appendix.

Forecasting Results

In the following section, we present the assumptions for and results of each of the three scenarios forecasted for Vancouver's economy: the baseline case, the high case, and the low case. In each case, Vancouver's economy eventually converges to the same long-run trend over the forecast period, albeit at different rates. This long-run trend is based on historical population and productivity growth and represents the average sustainable pace of growth for the economy. Because the COVID-19 pandemic is expected to be a temporary negative shock to the region's economy, its impact is anticipated to fade over time. The pace at which the economy converges to its long-run trend depends on the assumptions used in each forecast scenario.

Scenario 1: Baseline Case

Assumptions

- Social distancing measures will be relaxed only gradually until COVID-19 is no longer a domestic public health threat (i.e., until a treatment or vaccine is found).
- There is no second economy-wide shutdown. Regional or local shutdowns are still possible; but, nationally, restrictions are steadily relaxed.
- Global demand for resources and manufactured goods will remain weak as the Canadian and other economies do not operate at 100 per cent until an effective vaccine or treatment is available.
- Vaccine or treatment for the COVID-19 virus is found and widely available to Canadians by June 2021. COVID-19 is no longer an issue domestically.
- Wholesale and retail sales activity returns to normal by July 2021, although there could be a permanent shift to more online retailing.
- The vaccine is widespread globally by October 2021, prompting international travel to return to normal.
- Tourism, both outbound and inbound, is back to normal by the fall 2021.
- Adoption of telework is permanent for 5 to 10 per cent of the workforce, which has implications for commuter transportation, demand for automobiles, and gasoline, as well as for non-residential construction.
- Operating costs increase sharply for many businesses, so the federal wage subsidy is extended from April 2020 until June 2021 (i.e., until a vaccine available).
- Cost driven inflation starts to emerge despite excess capacity. However, this one-time transitory increase in prices does not sway the Bank of Canada to increase interest rates until 2022.

Results

In the baseline case, Vancouver's economy will largely recover from the COVID-19 pandemic over the short term (2020-2022). The end of social distancing measures, which have kept many sectors of the economy operating below capacity, are essential to this recovery. These measures are anticipated to be lifted once an effective COVID-19 vaccine or treatment is widely available to Canadians, which is assumed to be by June 2021.

After contracting by 5.0 per cent in 2020, real GDP is anticipated to rebound and push past 2019 levels in 2021 with a strong gain of 6.8 per cent. Employment, however, will take a bit longer to surpass pre-COVID-19 levels. In 2020, total employment is expected to contract by 7.1 per cent—a loss of 103,900 jobs. As a result of business closures and social distancing measures, the accommodation and food services and the arts, entertainment, and recreation industries are expected to post some of the largest job losses this year, shedding 27,700 and 11,800 positions, respectively. Although employment is anticipated to decline in nearly every industry this year, losses will be muted in sectors where work can be conducted remotely, such as in the professional and technical services industry and the education sector, which are expected to see declines of only 2,200 and 1,800 positions, respectively. In 2021, total employment is expected to rebound, but only regain about half of all jobs lost in 2020 with an expansion of 52,100 positions. Fortunately, Vancouver's labour market will rally further in 2022 and create another 81,000 jobs, pushing total employment past 2019 levels.

Meanwhile, the region's residential construction sector will log a solid performance in the short term thanks to steady population growth. Although border closures will limit international in-migration—a key component of Vancouver's demographic growth—weak job prospects across Canada will constrain out-migration from Vancouver, thus stabilizing the region's population growth to average 1.1 per cent annually between 2020 and 2022. After housing starts hit a record-high of 28,100 units in 2019, builders are expected to break ground on a further 20,900 units this year and an average of 21,700 annually over 2021-2022. This healthy level of new home construction will support average annual housing stock growth of 2.2 per cent between 2020 and 2022.

While the majority of COVID-19's negative impact will have dissipated by the end of 2022, the economy will continue to operate slightly below capacity over the medium term (2023-2029) as it rebuilds following the pandemic. Total real output is anticipated to grow at a steady average annual pace of 2.1 per cent, while employment is expected to advance at an average annual pace of 1.2 per cent—the equivalent of 18,900 jobs annually. Meanwhile, the economic recovery will begin to attract more domestic and international migrants to Vancouver, prompting population growth to accelerate to an average annual pace of 1.3 per cent between 2023 and 2029. These gains will support steady average annual housing starts of 18,300 units and average annual housing stock growth of 1.6 per cent over the same period. By the end of 2029, Vancouver's economy will have fully recovered from the COVID-19 pandemic and is set to grow at its long-run trend rate of growth over the remainder of the baseline forecast.

In the long term (2030-2040), Vancouver's economy will grow at a steady pace. Real GDP growth is expected to average an annual rate of 2.0 per cent over the period, while employment is anticipated to expand by an annual average of 1.0 per cent, or 17,100 jobs per year. These advances will be supported by healthy population growth, which is expected to average 1.0 per cent annually over the same period. This pace of population growth will also drive steady average annual starts of 14,300 units and an average annual increase in Vancouver's housing stock of 1.2 per cent between 2030 and 2040.

Please see Table 1 below for a more detailed look at the forecast results for the baseline case.

Table 1
Summary of Baseline Case Forecast Results

	2018	2019	2020f	2021f	2022f	2023f	2024f	2025-2029f	2030-2034f	2035-2040f
Total Real GDP (2012 $ millions)	148,556	153,341	145,683	155,580	161,246	164,933	168,300	179,478	198,695	221,149
	2.7	*3.2*	*-5.0*	*6.8*	*3.6*	*2.3*	*2.0*	*2.1*	*2.0*	*2.0*
Total Employment (Thousands)	1,425.8	1,474.0	1,370.1	1,422.2	1,503.2	1,530.9	1,544.2	1,599.4	1,684.0	1,777.8
	1.8	*3.4*	*-7.1*	*3.8*	*5.7*	*1.8*	*0.9*	*1.2*	*1.0*	*1.0*
Goods Producing Industries	255.7	240.3	230.5	234.4	250.2	252.0	253.6			
	6.9	*-6.0*	*-4.1*	*1.7*	*6.7*	*0.7*	*0.6*			
Manufacturing	103.3	96.2	87.9	91.1	98.8	99.5	98.4			
	3.2	*-6.9*	*-8.7*	*3.7*	*8.4*	*0.7*	*-1.1*			
Construction	130.2	123.3	118.7	123.8	130.3	131.0	133.6			
	10.0	*-5.3*	*-3.7*	*4.3*	*5.2*	*0.6*	*2.0*			
Primary and Utilities	22.2	20.8	23.9	19.5	21.1	21.5	21.6			
	7.1	*-6.0*	*14.7*	*-18.5*	*8.5*	*1.9*	*0.4*			
Services Producing Industries	1,170.1	1,233.7	1,139.6	1,187.9	1,253.1	1,278.9	1,290.6			
	0.7	*5.4*	*-7.6*	*4.2*	*5.5*	*2.1*	*0.9*			
Wholesale Trade	55.0	57.9	51.8	54.0	59.1	59.6	59.1			
	-7.2	*5.3*	*-10.6*	*4.3*	*9.5*	*0.8*	*-0.8*			
Retail Trade	149.5	172.4	164.8	170.9	178.5	179.1	177.2			
	-5.2	*15.3*	*-4.4*	*3.7*	*4.4*	*0.4*	*-1.1*			
Transportation & Warehousing	86.7	88.4	78.6	87.4	98.3	102.2	104.7			
	0.8	*2.0*	*-11.2*	*11.3*	*12.5*	*4.0*	*2.4*			
Information and Cultural Industries	45.5	44.0	42.2	41.9	41.6	44.5	45.1			
	-11.7	*-3.2*	*-4.2*	*-0.7*	*-0.6*	*6.7*	*1.5*			
Finance, Insurance, & Real Estate	164.3	183.1	171.2	181.2	178.7	177.4	177.8			
	-3.6	*11.4*	*-6.5*	*5.8*	*-1.4*	*-0.7*	*0.2*			

	2018	2019	2020f	2021f	2022f	2023f	2024f	2025-2029f	2030-2034f	2035-2040f
Professional, Scientific, & Technical Services	146.2	154.7	152.5	153.0	160.3	164.0	167.4			
	8.7	*5.9*	*-1.4*	*0.3*	*4.8*	*2.3*	*2.1*			
Educational Services	92.2	104.1	102.3	102.7	103.4	105.4	105.1			
	-3.6	*12.8*	*-1.7*	*0.4*	*0.6*	*2.0*	*-0.3*			
Health Care & Social Assistance	163.9	160.6	158.6	166.3	171.7	177.6	181.3			
	3.4	*-2.1*	*-1.2*	*4.8*	*3.2*	*3.4*	*2.1*			
Arts, Entertainment, & Recreation	43.2	44.6	32.7	41.2	42.5	44.7	46.4			
	4.4	*3.0*	*-26.5*	*25.8*	*3.2*	*5.1*	*3.7*			
Accommodation & Food Services	112.0	103.4	75.7	73.9	102.1	105.9	107.4			
	14.6	*-7.6*	*-26.8*	*-2.3*	*38.1*	*3.6*	*1.4*			
Other Services	65.4	68.7	63.4	64.9	65.0	66.7	67.6			
	6.6	*5.1*	*-7.7*	*2.4*	*0.1*	*2.7*	*1.3*			
Public Administration	46.1	51.7	45.8	50.4	51.8	51.8	51.6			
	-2.7	*12.2*	*-11.4*	*10.0*	*2.7*	*0.0*	*-0.3*			
Total Population (Thousands)	2,652	2,691	2,721	2,751	2,784	2,822	2,861	2,973	3,153	3,330
	1.5	*1.5*	*1.1*	*1.1*	*1.2*	*1.4*	*1.4*	*1.3*	*1.1*	*0.9*
Total Housing Starts (Thousands)	23.4	28.1	20.9	22.0	21.4	20.4	19.4	17.6	15.3	13.4
	-10.7	*20.2*	*-25.6*	*5.3*	*-3.1*	*-4.5*	*-4.8*	*-3.3*	*-2.4*	*-2.3*
Single Starts	4.6	3.4	3.2	3.3	3.1	2.9	2.7	2.3	1.8	1.5
	-6.5	*-25.4*	*-6.1*	*1.0*	*-4.0*	*-6.8*	*-7.2*	*-5.6*	*-3.7*	*-3.6*
Multiple Starts	18.8	24.7	17.7	18.8	18.3	17.5	16.7	15.3	13.5	11.9
	-11.7	*31.4*	*-28.3*	*6.0*	*-2.9*	*-4.1*	*-4.4*	*-2.9*	*-2.2*	*-2.2*
Total Housing Stock (Thousands)	1,010	1,034	1,059	1,083	1,105	1,125	1,145	1,197	1,281	1,364
	2.4	*2.3*	*2.4*	*2.3*	*2.0*	*1.9*	*1.8*	*1.5*	*1.3*	*1.1*

Notes: f=forecast. Numbers in italics denote annual percentage change for each year between 2018 and 2024. For the periods 2025-2029, 2030-2034, and 2035-2040, the level values listed in the table denote the average value of each variable over that period, while the numbers in italics denote annual average percentage change over that period.
Sources: The Conference Board of Canada; Statistics Canada.

Scenario 2: High Case

Assumptions

- All non-essential business is closed, and borders remain closed to international travellers between mid-March and end of April 2020.
- Borders remain shut to personal travel, and the negative impact on demand for recreation, culture, accommodations, and restaurants continues from May to August 2020.
- Most industries will experience a negative shock to demand, with some such as accommodations and food services, travel, cultural industries, and many segments of retail experiencing a near-total collapse in activity from mid-March to April 2020.
- Manufacturing is mostly shuttered outside of essential items like pharmaceuticals, personal protective equipment and medical products, and food between mid-March and the end of April 2020.
- The construction industry slows significantly as some of its activities are deemed non-essential and forced to stop between mid-March and April 2020.
- Non-essential businesses gradually begin to re-open over the summer months, from May to August 2020.
- The financial fallout on households' balance sheets continues to weigh negatively on discretionary spending, particularly on pricier durable products like vehicle sales, from May to August 2020.
- The federal wage subsidy program positions businesses to quickly rehire as demand picks up, allowing the labour market recovery to begin between May and August 2020 and setting the foundation for stronger growth heading into the fall.
- Most aspects of the economy have returned to normal operations between September 2020 and February 2021.
- Borders re-open to international passengers between September 2020 and February 2021, but volumes remain well below pre-COVID-19 levels.
- Cultural events and recreation activities slowly resume from September 2020 to February 2021.

Results

In the high case, COVID-19's negative impact is assumed to be both weaker and shorter compared to the baseline case, with Vancouver's economy expected to make a full recovery by the end of the short-term (2020-2022). Unlike in the baseline case, social distancing measures are not as strict and allow the economy to recover more quickly. Most sectors of the economy are expected to return to normal by early 2021.

After contracting by a moderate 3.0 per cent in 2020, total real GDP is anticipated to post a strong recovery and expand by 6.5 per cent in 2021. At the same time, Vancouver's labour market is expected to contract by a similar 3.2 per cent—the equivalent of 47,800 jobs. The worst performances in 2020 are expected in the arts, entertainment, and recreation, the finance, insurance, and real estate, and the accommodation and food services industries with job losses of 11,300, 8,500, and 7,200, respectively, as people choose to limit their activities outside the home. Fortunately, employment is anticipated to bounce back and exceed 2019 levels by the end of 2021. While employment in some industries will still fall short of their 2019 levels next year, total employment is expected to rise by 4.9 per cent, or 70,000 jobs. In 2022, Vancouver's economy is expected to create a further 11,500 jobs as the region continues to move past the COVID-19 shock.

At the same time, population and housing growth will only face minor disruptions due to COVID-19. Population growth is expected to slow from 1.5 per cent in 2019 to 1.1 per cent in 2020 as a result of a significant drop in international in-migration due to international border closures. As international travel returns to normal after August 2020, the pace of population growth is anticipated to accelerate to 1.2 per cent in 2021 and 1.3 per cent in 2022. These gains will support healthy demand for new home construction. Although housing starts will fall from a record-high of 28,100 units last year to 21,000 units this year, they are expected to rebound to 24,100 units in 2021 before easing to 20,800 units in 2022. This level of residential construction will push Vancouver's housing stock to expand at an average annual pace of 2.3 per cent between 2020 and 2022.

By 2023, Vancouver is expected to recover fully from the COVID-19 shock. Therefore, the economy is anticipated to operate at capacity over the medium term (2023-2029) and is set to grow at its long-run trend rate of growth by 2025. Real GDP is projected to advance at an average annual pace of 2.0 per cent between 2023 and 2029, while employment is expected to grow an average annual pace of 1.2 per cent—the equivalent of 18,300 jobs annually. At the same time, Vancouver's healthy economic performance will attract more people to the region, driving average annual population growth of 1.3 per cent over the same period. These gains will support average housing starts of 18,200 units annually and average annual housing stock growth of 1.6 per cent between 2023 and 2029.

In the long term (2030-2040), Vancouver's economy in the high case will grow at the same pace as in the baseline case. Real output is expected to grow at an average annual pace of 2.0 per cent over the period, while employment is anticipated to advance at an average annual pace of 1.0 per cent, or 17,100 jobs annually. Meanwhile, population growth is expected to average 1.0 per cent annually. This steady influx of people will support average annual new home construction of 14,300 units and an average annual increase in the region's housing stock of 1.2 per cent between 2030 and 2040.

Please see Table 2 below for a more detailed look at the forecast results for the high case.

Table 2
Summary of High Case Forecast Results

	2018	2019	2020f	2021f	2022f	2023f	2024f	2025-2029f	2030-2034f	2035-2040f
Total Real GDP (2012 $ millions)	148,344	152,556	148,017	157,683	161,644	164,805	167,870	178,853	197,910	220,364
	2.6	*2.8*	*-3.0*	*6.5*	*2.5*	*2.0*	*1.9*	*2.1*	*2.0*	*2.0*
Total Employment (Thousands)	1,425.8	1,474.0	1,426.3	1,496.3	1,507.8	1,528.8	1,543.3	1,601.5	1,684.0	1,777.8
	1.8	*3.4*	*-3.2*	*4.9*	*0.8*	*1.4*	*0.9*	*1.2*	*1.0*	*1.0*
Goods Producing Industries	255.6	240.3	240.0	245.2	249.2	250.6	253.1			
	6.9	*-6.0*	*-0.1*	*2.1*	*1.7*	*0.6*	*1.0*			
Manufacturing	103.3	96.2	95.0	96.9	98.6	99.0	98.6			
	3.2	*-6.9*	*-1.2*	*2.0*	*1.8*	*0.3*	*-0.4*			
Construction	130.2	123.3	124.0	127.2	129.1	129.9	132.6			
	10.0	*-5.3*	*0.6*	*2.6*	*1.5*	*0.7*	*2.1*			
Primary and Utilities	22.1	20.9	21.0	21.1	21.5	21.7	21.9			
	7.1	*-5.8*	*0.8*	*0.3*	*1.9*	*1.1*	*1.0*			
Services Producing Industries	1,170.2	1,233.7	1,186.2	1,251.1	1,258.5	1,278.2	1,290.2			
	0.7	*5.4*	*-3.8*	*5.5*	*0.6*	*1.6*	*0.9*			
Wholesale Trade	55.0	57.9	57.6	59.6	59.9	59.7	59.2			
	-7.2	*5.3*	*-0.5*	*3.4*	*0.5*	*-0.3*	*-0.9*			
Retail Trade	149.5	172.4	170.9	178.1	179.8	179.9	177.2			
	-5.2	*15.3*	*-0.9*	*4.2*	*1.0*	*0.0*	*-1.5*			
Transportation & Warehousing	86.8	88.5	82.4	94.0	98.2	101.0	104.5			
	0.8	*2.0*	*-6.8*	*14.1*	*4.4*	*2.9*	*3.4*			
Information and Cultural Industries	45.5	44.0	39.9	41.3	42.8	43.7	43.3			
	-11.7	*-3.3*	*-9.4*	*3.6*	*3.6*	*2.2*	*-1.1*			
Finance, Insurance, & Real Estate	164.3	183.0	174.5	181.0	176.6	177.5	177.9			
	-3.7	*11.4*	*-4.7*	*3.8*	*-2.5*	*0.5*	*0.2*			

	2018	2019	2020f	2021f	2022f	2023f	2024f	2025-2029f	2030-2034f	2035-2040f
Professional, Scientific, & Technical Services	146.2	154.7	151.3	157.2	160.1	163.9	167.3			
	8.7	*5.8*	*-2.2*	*3.9*	*1.9*	*2.3*	*2.1*			
Educational Services	92.3	104.1	103.2	104.2	104.3	104.5	105.1			
	-3.6	*12.8*	*-0.9*	*1.0*	*0.1*	*0.1*	*0.6*			
Health Care & Social Assistance	163.9	160.6	164.9	167.0	172.1	177.5	180.5			
	3.4	*-2.1*	*2.7*	*1.3*	*3.1*	*3.1*	*1.7*			
Arts, Entertainment, & Recreation	43.2	44.6	33.3	43.7	43.7	45.0	46.4			
	4.6	*3.2*	*-25.3*	*31.1*	*0.0*	*3.1*	*3.0*			
Accommodation & Food Services	112.0	103.4	96.3	109.6	103.7	106.2	109.1			
	14.5	*-7.6*	*-6.9*	*13.9*	*-5.4*	*2.4*	*2.7*			
Other Services	65.3	68.7	64.3	65.3	66.2	67.7	69.0			
	6.5	*5.2*	*-6.4*	*1.6*	*1.4*	*2.3*	*1.9*			
Public Administration	46.1	51.7	47.7	50.1	51.1	51.5	50.8			
	-2.7	*12.2*	*-7.8*	*5.0*	*2.1*	*0.7*	*-1.2*			
Total Population (Thousands)	2,652	2,691	2,722	2,754	2,789	2,826	2,865	2,975	3,153	3,330
	1.5	*1.5*	*1.1*	*1.2*	*1.3*	*1.3*	*1.4*	*1.2*	*1.1*	*0.9*
Total Housing Starts (Thousands)	23.4	28.1	21.0	24.1	20.8	20.2	19.5	17.5	15.3	13.4
	-10.7	*20.2*	*-25.3*	*14.6*	*-13.7*	*-2.8*	*-3.3*	*-3.4*	*-2.4*	*-2.3*
Single Starts	4.6	3.4	3.2	3.5	2.8	2.7	2.6	2.2	1.8	1.5
	-6.5	*-25.4*	*-5.2*	*7.1*	*-18.5*	*-4.8*	*-5.2*	*-4.5*	*-3.7*	*-3.6*
Multiple Starts	18.8	24.7	17.8	20.6	18.0	17.5	17.0	15.3	13.5	11.9
	-11.7	*31.4*	*-28.0*	*16.0*	*-12.9*	*-2.5*	*-3.0*	*-3.2*	*-2.2*	*-2.2*
Total Housing Stock (Thousands)	1,010	1,034	1,058	1,083	1,105	1,126	1,145	1,198	1,281	1,364
	2.4	*2.3*	*2.3*	*2.4*	*2.1*	*1.8*	*1.7*	*1.5*	*1.3*	*1.1*

Notes: f=forecast. Numbers in italics denote annual percentage change for each year between 2018 and 2024. For the periods 2025-2029, 2030-2034, and 2035-2040, the level values listed in the table denote the average value of each variable over that period, while the numbers in italics denote annual average percentage change over that period.
Sources: The Conference Board of Canada; Statistics Canada.

Scenario 3: Low Case

Assumptions

- Social distancing measures will be relaxed only gradually until COVID-19 is no longer a domestic public health threat (i.e., until a treatment or vaccine is found).
- There is no second economy-wide shutdown. Regional or local shutdowns are still possible; but, nationally, restrictions are steadily relaxed. Food services could see much slower growth as people decide not to go to bars and restaurants to avoid possible exposure to COVID-19.
- Global demand for resources and manufactured goods will remain weak as the Canadian and other economies do not operate at 100 per cent until an effective vaccine or treatment is available.
- Vaccine or treatment for COVID-19 virus is found and available, widespread globally by Summer 2022. (June 2021 in the baseline case).
- Adoption of telework and distance education is permanent for 25 per cent of the population, which has implications for commuter transportation, demand for automobiles, and gasoline, as well as for non-residential construction. (5 to 10 per cent of workforce in the baseline case).
- Operating costs increase sharply for many businesses, so the federal wage subsidy is extended until Summer 2022 (i.e., until a vaccine available).
- Cost driven inflation starts to emerge despite excess capacity. However, this one-time transitory increase in prices does not sway the Bank of Canada to increase interest rates.
- The economic shock resulting from the COVID-19 pandemic in the spring of 2020 has a long-term negative impact on consumer and business confidence, resulting in weak business investment and consumer spending through the rest of 2020 and 2021, both globally and domestically.
- Global and Canadian consumers are delaying the purchases of durable goods and other large investments, such as home, cars, furniture, and renovation spending.
- Depressed demand from both businesses and consumers results in significantly weaker demand for Canadian goods from the U.S. and China through the rest of 2020 through to the end of 2023.
- Weaker economic prospects combined with restrictions on international travel constrain international migration and thus slow population growth, impacting housing starts between 2020 and 2024.
- Domestically, we see a significant contraction in home prices (15 to 25 per cent) and housing starts over the next two years, impacting residential construction activity through the end of 2022.
- In addition to a permanent shift towards online shopping, depressed consumer spending will weigh further on the retail trade sector. As a result, retail employment will not return to 2019 levels within the five-year forecast (2020 to 2024).
- International tourism will gradually recover but will not go back to 2019 levels within the five-year forecast period (2020 to 2024).

- The employment recovery is much more subdued. Global and Canadian businesses are reluctant to re-hire all the staff let go during the height of the crisis. Total employment does not return to its 2019 level by the end of 2024.
- Vancouver's key economic series do not return to their long-run levels until 2035.

Results

In the low case, Vancouver's economy is projected to recover from the COVID-19 pandemic at a much slower pace compared to the baseline case. While the end of social distancing measures following the availability of an effective COVID-19 vaccine or treatment in summer of 2022 will help the economy recover, the pandemic's impact on consumer and business confidence, both domestically and internationally, will lead to a deeper and more prolonged recession. As a result, nearly every sector of Vancouver's economy will remain below pre-pandemic levels in the short term (2020-2022).

Following the economy-wide shutdown in in the spring, most of Vancouver's industries are expected to post little to no recovery over the rest of 2020 due to the persistence of COVID-19, weak international and domestic demand for goods and services, and a lack of confidence in the global economy. As a result, real GDP is expected to contract by 6.6 per cent overall in 2020. While output is expected to rebound and advance by 2.5 per cent in 2021 and 4.1 per cent in 2022, total GDP will still fall short of 2019 levels by the end of 2022.

Vancouver's labour market is expected to follow an even weaker recovery path. After falling by 9.6 per cent—the equivalent of 141,800 jobs—in 2020, employment is expected to contract by a further 1.2 per cent, or 16,200 jobs, in 2021, as businesses are reluctant to re-hire staff due to weak confidence in the economy. The accommodation and food services industry will suffer the greatest losses, shedding more than 30,000 jobs in 2020 and a further 10,000 jobs in 2021 due to depressed international visitor numbers and low domestic demand for dine-in restaurant meals. At the same time, weak business investment and a 15 to 25 per cent contraction in home prices will contribute to a loss of 18,400 jobs in the finance, insurance, and real estate industry in 2020. Finally, the retail trade industry will shed 15,600 jobs in 2020 in the face of low consumer spending, particularly on expensive durable goods. Although employment in every industry is expected to increase in 2022, the region's economy is only expected to reclaim 53,500 of the jobs lost over 2020-2021, leaving the labour market 104,500 short of 2019 levels by the end of 2022.

Vancouver's weak economic prospects will also impact the region's pace of population growth and residential construction over the short term. Slower international migration due to global travel restrictions will cool population growth from 1.5 per cent in 2019 to 1.0 per cent in 2020 before easing further to average an annual pace of 0.8 per cent between 2021 and 2022. This, along with weak consumer confidence and a significant contraction in home prices, will lead to much slower residential construction activity. After hitting a record high of 28,100 units in 2019, total housing starts are expected to drop to 19,300 in 2020 before cooling further to 17,300 units in 2021 and 16,000 units in 2022. In line with this slower pace of new home construction, housing stock growth is expected to ease from 2.3 per cent in 2019 to average 1.8 per cent annually between 2020 and 2022.

Despite the availability of an effective COVID-19 vaccine by the summer of 2022, Vancouver's economic recovery over the medium term (2023-2029) will be slow and subdued due to persistently weak consumer and business confidence at home and abroad. Real GDP is expected to advance at an average annual pace of 2.7 per cent between 2023 and 2029, with total output surpassing 2019 levels by the end of 2023. Meanwhile, employment is anticipated to grow by an average of 2.2 per cent annually—the equivalent of 32,400 jobs per year—over the same period. With businesses facing uncertainty around global and domestic demand, they are expected to rehire staff let go during the pandemic at a gradual pace. As a result, total employment is only anticipated to surpass 2019 levels by the end of 2025. At the same time, Vancouver's gradually improving economic prospects, along with the easing of international travel restrictions, will help population growth accelerate to an average annual pace of 1.3 per cent between 2023 and 2029 from 0.9 per cent over 2020-2022. Despite these gains, housing starts will only average 16,500 units annually over the medium term due to weak home prices, subdued international in-migration, and slowly recovering consumer confidence. This level of new home construction will drive average annual housing stock growth of 1.6 per cent between 2022 and 2029, though total housing stock will be lower compared to the baseline case.

Vancouver's recovery will continue over the long term (2030-2040), with the economy set to grow at its long-run trend rate of growth by 2035. Real GDP is expected to grow at an average annual pace of 2.1 per cent between 2030 and 2040, with output growing at a faster pace in the first half of the decade as the economy gradually operates closer to capacity. At the same time, employment is anticipated to expand at an average annual rate of 1.2 per cent, or 20,700 jobs annually. In line with the region's stronger job prospects, population is expected to grow at an average annual pace of 1.1 per cent. This steady influx of people into Vancouver will help support annual average new residential construction of 14,200 units and, in turn, increase the total housing stock at an average annual pace of 1.3 per cent between 2030 and 2040.

Please see Table 3 below for a more detailed look at the forecast results for the low case.

Table 3
Summary of Low Case Forecast Results

	2018	2019	2020f	2021f	2022f	2023f	2024f	2025-2029f	2030-2034f	2035-2040f
Total Real GDP (2012 $ millions)	148,556	153,341	143,264	146,840	152,841	158,705	163,596	176,488	197,974	221,149
	2.7	*3.2*	*-6.6*	*2.5*	*4.1*	*3.8*	*3.1*	*2.5*	*2.2*	*2.0*
Total Employment (Thousands)	1,425.8	1,474.0	1,332.3	1,316.0	1,369.5	1,426.7	1,467.2	1,545.4	1,668.6	1,777.8
	1.8	*3.4*	*-9.6*	*-1.2*	*4.1*	*4.2*	*2.8*	*1.7*	*1.5*	*1.0*
Goods Producing Industries	255.7	240.3	225.4	215.9	223.2	231.2	239.7			
	6.9	*-6.0*	*-6.2*	*-4.2*	*3.4*	*3.6*	*3.7*			
Manufacturing	103.3	96.2	84.6	79.9	81.5	85.3	90.6			
	3.2	*-6.9*	*-12.1*	*-5.6*	*2.0*	*4.7*	*6.3*			
Construction	130.2	123.3	116.9	117.5	121.7	125.3	128.1			
	10.0	*-5.3*	*-5.2*	*0.5*	*3.6*	*3.0*	*2.2*			
Primary and Utilities	22.2	20.8	23.9	18.5	20.0	20.6	21.0			
	7.1	*-6.0*	*14.6*	*-22.6*	*8.4*	*3.1*	*2.0*			
Services Producing Industries	1,170.1	1,233.7	1,106.9	1,100.1	1,146.3	1,195.5	1,227.5			
	0.7	*5.4*	*-10.3*	*-0.6*	*4.2*	*4.3*	*2.7*			
Wholesale Trade	55.0	57.9	51.3	48.8	52.2	54.1	55.0			
	-7.2	*5.3*	*-11.3*	*-4.9*	*7.0*	*3.6*	*1.5*			
Retail Trade	149.5	172.4	156.8	159.8	161.6	163.2	165.0			
	-5.2	*15.3*	*-9.1*	*1.9*	*1.1*	*1.0*	*1.1*			
Transportation & Warehousing	86.7	88.4	75.6	74.5	79.1	88.1	96.1			
	0.8	*2.0*	*-14.5*	*-1.5*	*6.2*	*11.3*	*9.2*			
Information and Cultural Industries	45.5	44.0	39.2	39.2	39.6	39.7	39.9			
	-11.7	*-3.2*	*-11.1*	*0.1*	*1.0*	*0.3*	*0.5*			
Finance, Insurance, & Real Estate	164.3	183.1	164.7	163.3	166.4	169.1	173.5			
	-3.6	*11.4*	*-10.1*	*-0.8*	*1.9*	*1.7*	*2.6*			

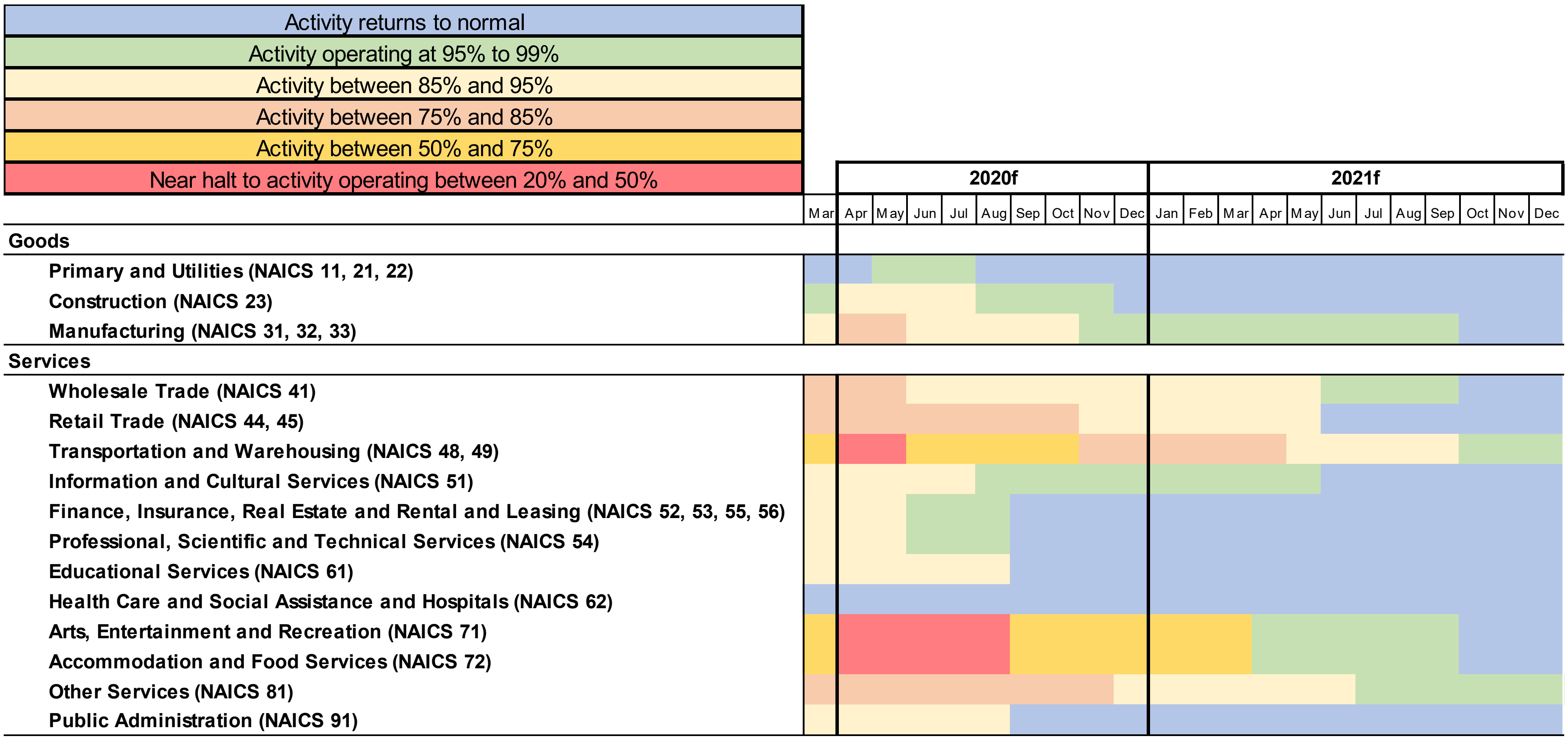
	2018	2019	2020f	2021f	2022f	2023f	2024f	2025-2029f	2030-2034f	2035-2040f
Professional, Scientific, & Technical Services	146.2	154.7	151.0	146.7	150.0	153.7	157.3			
	8.7	*5.9*	*-2.4*	*-2.9*	*2.3*	*2.5*	*2.4*			
Educational Services	92.2	104.1	100.9	100.1	100.5	101.1	101.8			
	-3.6	*12.8*	*-3.1*	*-0.7*	*0.4*	*0.6*	*0.7*			
Health Care & Social Assistance	163.9	160.6	158.2	165.8	171.3	177.2	181.4			
	3.4	*-2.1*	*-1.4*	*4.8*	*3.4*	*3.4*	*2.4*			
Arts, Entertainment, & Recreation	43.2	44.6	30.8	33.2	37.1	39.6	41.7			
	4.4	*3.0*	*-30.8*	*7.8*	*11.5*	*6.8*	*5.4*			
Accommodation & Food Services	112.0	103.4	73.3	63.3	79.4	95.5	99.1			
	14.6	*-7.6*	*-29.1*	*-13.7*	*25.5*	*20.2*	*3.8*			
Other Services	65.4	68.7	60.3	58.4	60.0	64.1	65.8			
	6.6	*5.1*	*-12.3*	*-3.0*	*2.7*	*6.8*	*2.6*			
Public Administration	46.1	51.7	44.7	47.1	49.1	50.1	50.9			
	-2.7	*12.2*	*-13.6*	*5.3*	*4.3*	*2.1*	*1.5*			
Total Population (Thousands)	2,652	2,691	2,718	2,737	2,761	2,789	2,819	2,939	3,140	3,330
	1.5	*1.5*	*1.0*	*0.7*	*0.9*	*1.0*	*1.1*	*1.4*	*1.3*	*0.9*
Total Housing Starts (Thousands)	23.4	28.1	19.3	17.3	16.0	16.6	17.1	16.3	15.1	13.4
	-10.7	*20.2*	*-31.5*	*-10.3*	*-7.3*	*3.8*	*2.8*	*-1.5*	*-1.7*	*-2.3*
Single Starts	4.6	3.4	3.0	2.5	2.3	2.4	2.4	2.2	1.8	1.5
	-6.5	*-25.4*	*-13.5*	*-14.4*	*-7.7*	*1.6*	*0.0*	*-3.1*	*-3.7*	*-3.6*
Multiple Starts	18.8	24.7	16.3	14.8	13.7	14.3	14.7	14.2	13.3	11.9
	-11.7	*31.4*	*-34.0*	*-9.5*	*-7.2*	*4.2*	*3.2*	*-1.3*	*-1.4*	*-2.2*
Total Housing Stock (Thousands)	1,010	1,034	1,057	1,075	1,092	1,107	1,123	1,180	1,274	1,364
	2.4	*2.3*	*2.2*	*1.7*	*1.5*	*1.4*	*1.4*	*1.6*	*1.5*	*1.1*

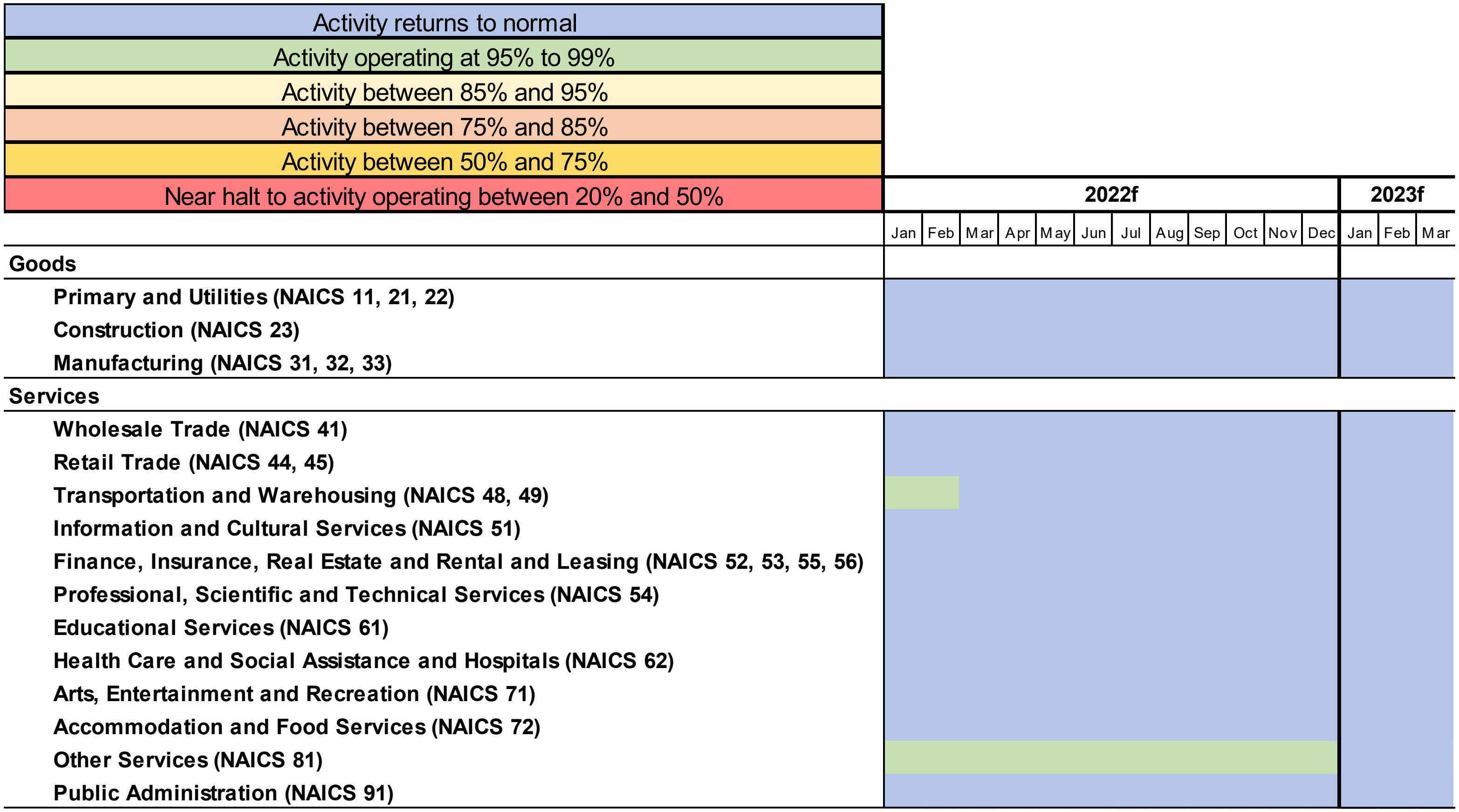
Notes: f=forecast. Numbers in italics denote annual percentage change for each year between 2018 and 2024. For the periods 2025-2029, 2030-2034, and 2035-2040, the level values listed in the table denote the average value of each variable over that period, while the numbers in italics denote annual average percentage change over that period.
Sources: The Conference Board of Canada; Statistics Canada.

Appendix

Figure 1

Baseline scenario recovery path for employment by industry, March 2020 to March 2022

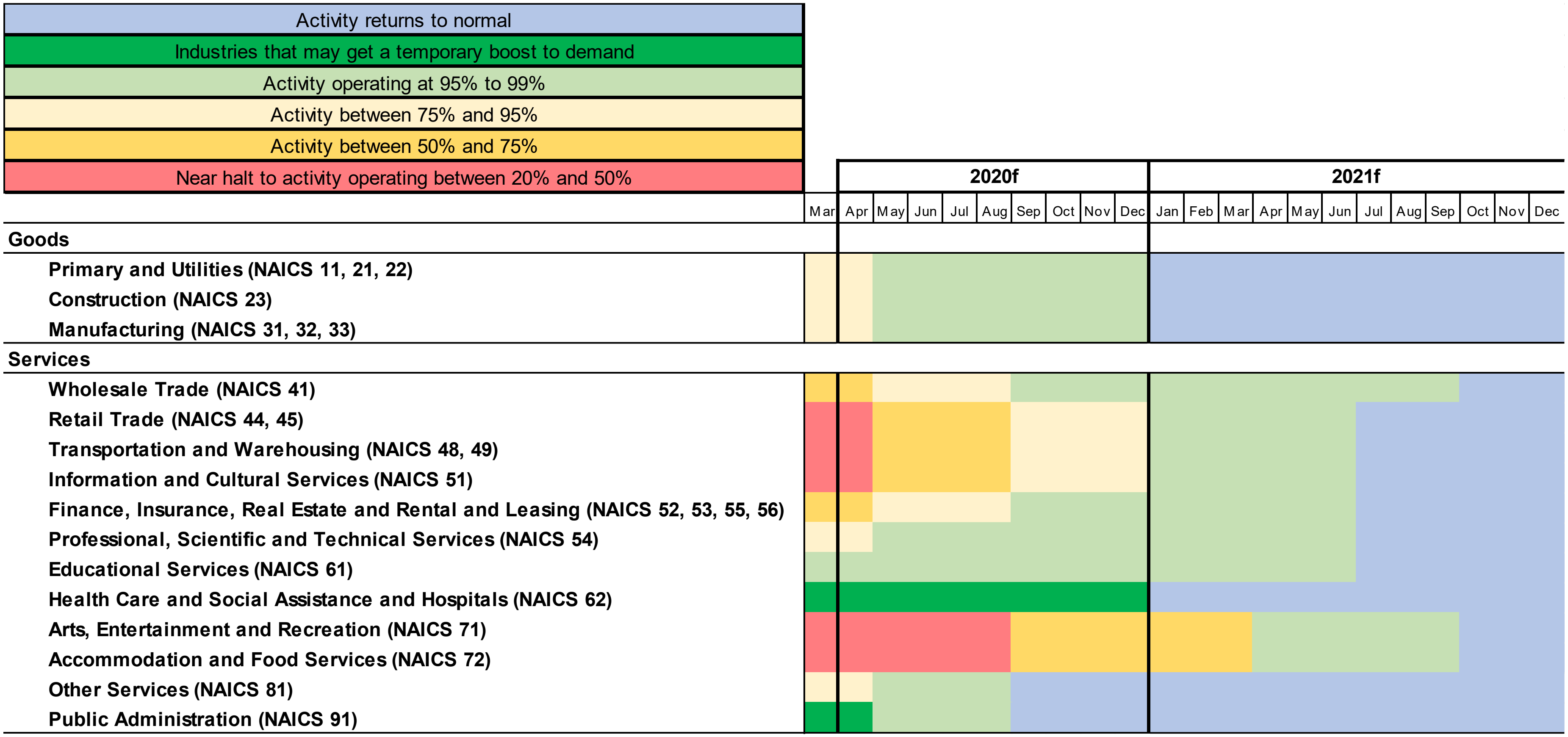




f=forecast.
Source: The Conference Board of Canada.

Figure 2

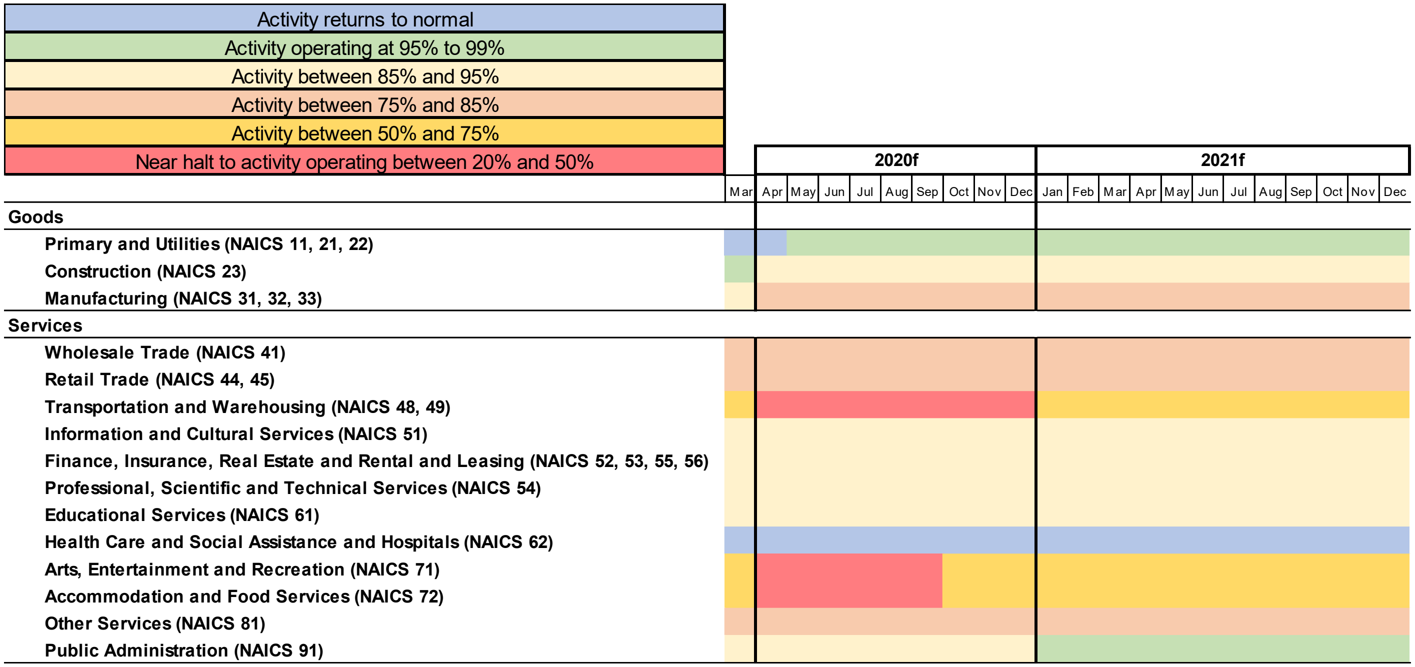
High scenario recovery path for employment by industry, March 2020 to December 2021

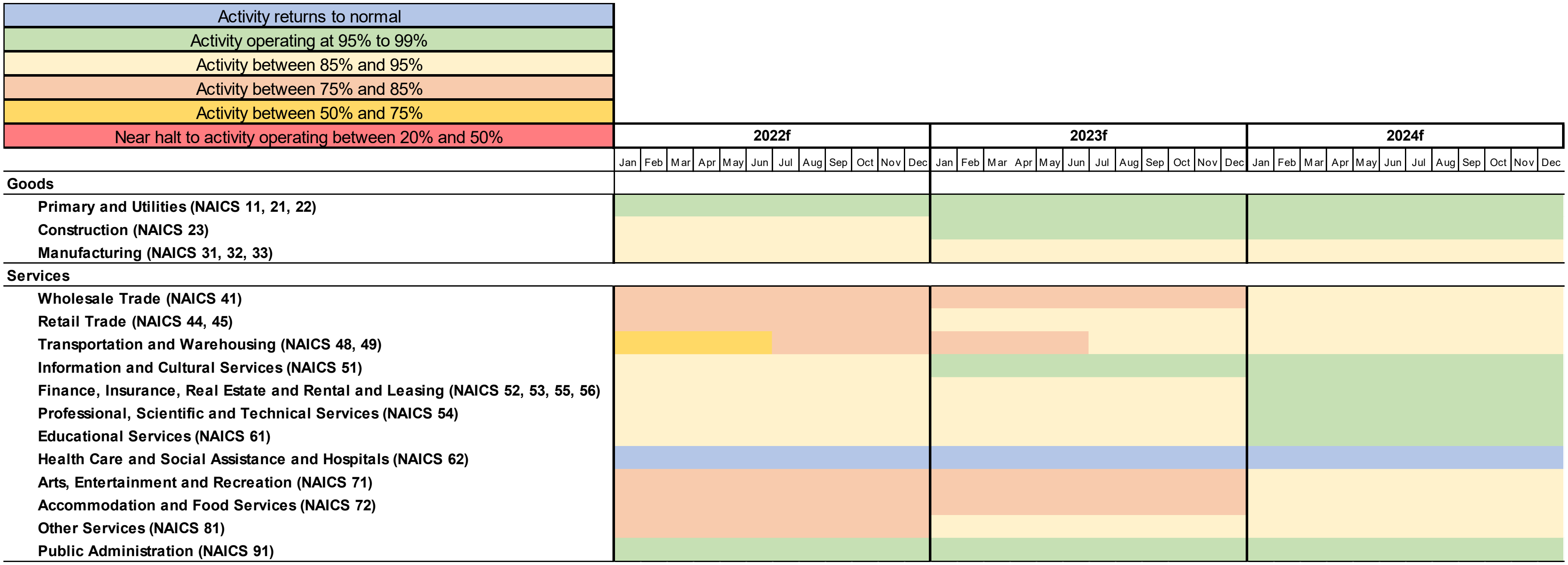


f=forecast.
Source: The Conference Board of Canada.

Figure 3

Low scenario recovery path for employment by industry, March 2020 to December 2024





f=forecast.
Source: The Conference Board of Canada.

Where insights meet impact

The Conference
Board of Canada

conferenceboard.ca

Appendix F: Navius Report

British Columbia Electrification Impacts Study

Forecasting the Impact of Achieving British Columbia's Greenhouse Gas Emissions Targets on Provincial Electricity Consumption

ELECTRIC LOAD FORECAST REPORT F2021 – F2041

SUBMITTED TO

BC Hydro
August 9th, 2021

SUBMITTED BY

Navius Research Inc.
355 Burrard St., Suite 410
PO Box 48300 Bentall,
Vancouver BC V7X 1A1

Contact@NaviusResearch.com
www.naviusresearch.com

Navius Research Inc. (“Navius”) is a private consulting firm in Vancouver. Our consultants specialize in analysing government and corporate policies designed to meet environmental goals, with a focus on energy and greenhouse gas emission policy. They have been active in the energy and climate change field since 2004 and are recognized among Canada’s leading experts in modeling the environmental and economic impacts of energy and climate policy initiatives. Navius is uniquely qualified to provide insightful and relevant analysis in this field because:

- We have a broad understanding of energy and environmental issues both within and outside of Canada.
- We use unique in-house models of the energy-economy system as principal analysis tools
- We have a strong network of experts in related fields with whom we work to produce detailed and integrated climate and energy analyses.
- We have gained national and international credibility for producing sound, unbiased analyses for clients from every sector, including all levels of government, industry, labour, the non-profit sector, and academia.

We are proud to have worked with the following clients:

- **Provincial, territorial and municipal governments:** Alberta, British Columbia, New Brunswick, Newfoundland and Labrador, Northwest Territories, Nova Scotia, Ontario, Vancouver
- **Federal government:** Environment and Climate Change Canada, Natural Resources Canada, National Roundtable on the Environment and the Economy
- **Utilities and the energy sector:** Advanced Biofuels Canada, BC Hydro, Canadian Association of Petroleum Producers, Canadian Gas Association, Kinder Morgan Canada, National Energy Board, Ontario Energy Board, Powerex Corp, Power Workers' Union, Spectra Energy, Western Canada Biodiesel Association
- **Non-profit and research:** Carbon Management Canada, Clean Energy Canada, Climate Action Network Canada, David Suzuki Foundation, Ecofiscal Commission, Electric Power Research Institute, Équiterre, Environmental Defense Fund, Pembina Institute, Pacific Institute for Climate Solutions

Executive Summary

Introduction

The greenhouse gas (GHG) reduction policies implemented by the government of British Columbia and the Government of Canada will change the quantity and type of energy consumed in British Columbia (BC) in the future. Specifically, GHG reduction policy may result in significant electrification of some energy end-uses, allowing the substitution of fossil fuels with renewable energy (e.g. wind, hydro, solar power), delivered via the electricity system. Electricity consumption may increase for end-uses where that fuel is not currently widely used, such as transportation, or where there is significant share of other fuel fuels consumed, such as building space and water heating.

This potential change in electricity consumption is of interest to BC Hydro. Understanding the drivers of energy consumption will help with the utility's electricity system planning. The extent of electrification is largely a function of electric technology capital and energy costs compared with the cost of the conventional and alternative fuels that may compete or complement the use of electricity in a low-GHG future.

The goal of this project is to analyse the uncertainty in future electricity demand created by current and potential energy and GHG policies as well as the cost and performance of emerging energy technologies whose adoption will be incentivized by these policies. In doing so, this analysis will provide reasonable bookends for future electricity consumption in BC, while explaining the drivers of this consumption (e.g. technology market shares, fuel shares by sector, use of alternatives e.g. biofuels).

Methodology

In this analysis, we used a technologically detailed, full-economic equilibrium, energy economy model to simulate how different GHG policy portfolios will affect electricity consumption in BC from the present to 2040.

We tested the impact of:

- **"Current policies", that are legislated or have firm announcements.** These include the BC carbon tax, rising to \$50/tCO_2e by 2022 and other policies that generally date from the fist BC Climate Action Plan, released in 2008. This scenario also includes the announced light-duty (passenger) vehicle zero-emissions vehicle (ZEV) standard that requires a minimum fraction of sales be ZEVs and is trending towards a phase-out of conventional vehicles by 2040.

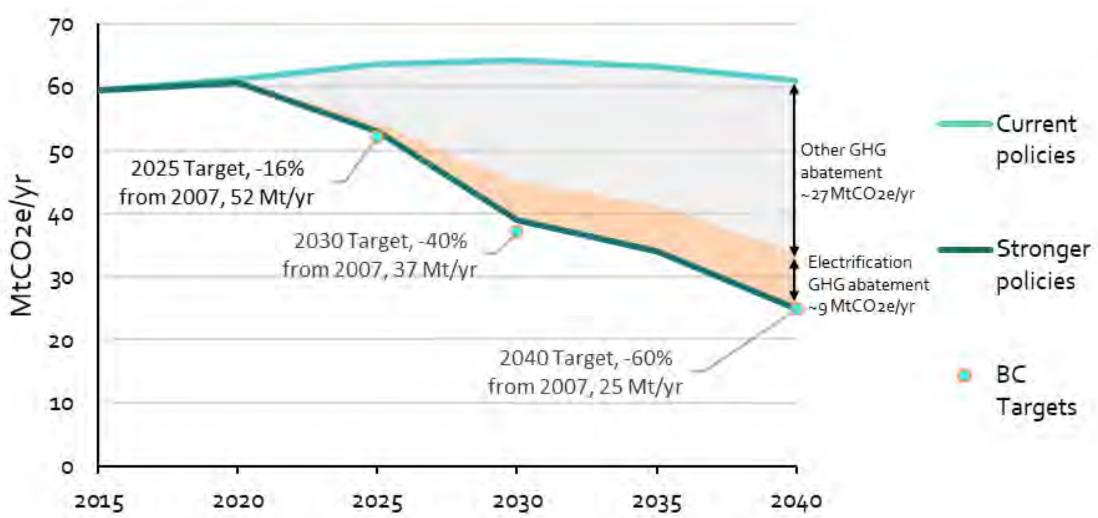
- **"Stronger policies", which include a range of stronger incentives and regulatory policies, plus an emissions cap that achieves BC's 2025, 2030 and 2040 GHG reduction targets**. These are a 16% reduction from 2007 emissions by 2025, a 40% reduction by 2030 and 60% reduction by 2040.

Using the stronger policy scenario as a reference, we also tested how the forecast of electricity demand is affected by a range of different technology costs assumptions, notably the cost of all classes of on-road battery electric vehicles. An additional sensitivity analysis looks at the impact of less stringent building regulations after 2030 (i.e. no requirement to retrofit building envelopes and no requirement for zero-GHG heating systems).

Results and Conclusions

The implementation of stronger policies substantially reduces British Columbia's total GHG emissions from the present and relative to a scenario with current policies. Electrification is an important GHG abatement action. With currently legislated policies, provincial GHG emissions are able the offset the growth of the population and the economy to keep GHG emissions roughly constant to 2040. By design, the stronger policy scenario hits the legislated GHG targets in 2025, 2030 and 2040 (Summary Figure 1). By 2040, electrification accounts for 25% of GHG abatement relative to the current policy scenario (about 9 of 36 $MtCO_2e$).

Summary Figure 1: BC GHG emissions by scenario and breakdown of GHG abatement



Of the dynamics tested, **BC's long-term electricity demand is most sensitive to the strength of climate policy**. In 2025, the difference in electricity demand between current policies and stronger policies is relatively small, just 1 TWh/yr more if BC achieves its GHG target. This difference grows to 10 TWh/yr in 2030 (+17%) and 12 TWh/yr in 2040 (+18%, with total electricity demand at 83 TWh/yr). (Summary Table 1).

Summary Table 1: BC electricity demand by scenario (TWh/yr)

	2015	2020	2025	2030	2035	2040
Current policies	51.4	53.5	56.9	61.3	65.5	70.7
Stronger policies	51.4	53.5	57.9	71.3	75.8	82.9

Most of this incremental growth in electricity demand comes from the natural gas sector and from buildings. In 2040, 45% of the incremental demand comes the electrification of compressors used for natural gas production and transportation. Another 38% of the incremental demand comes the electrification of space and water heating in buildings. 18% of incremental demand comes from transportation. Electricity demand for transportation must grow significantly in order to achieve deep GHG reductions in BC. However, much of this load growth is already included in the current policy forecast since it includes the light-duty vehicle ZEV standard.

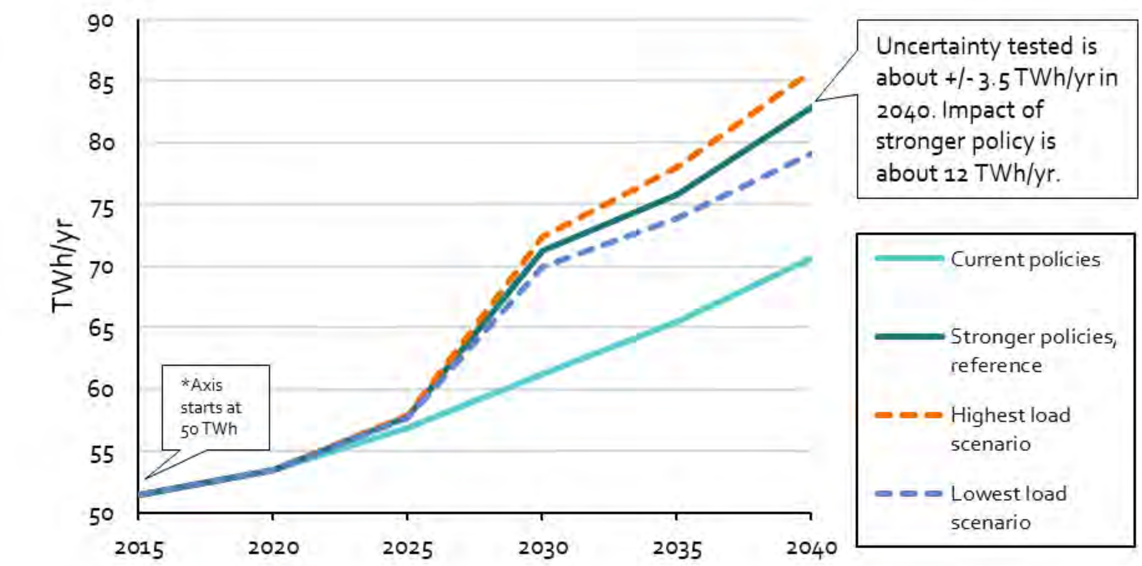
In contrast to the impact of GHG policy, **the other uncertainties tested in this analysis only shift total electricity demand in 2040 by a few TWh/yr relative to the reference forecast with stronger policies** (Summary Figure 2):

- **The future cost of plug-in electric vehicles (PEVS) is the largest uncertainty, but a wide range of assumptions only shifts electricity demand by around +/- 3.5 TWh/yr in 2040.** Two thirds of this range comes from greater or lesser adoption of light-duty PEVs after 2030, when low-cost PEVs combined with a strong carbon price drives sales beyond what the ZEV standard requires. The remaining third of this range comes from medium and heavy-duty PEVs. Even when assuming lower costs, PEVs are still a minority of these vehicle classes, used for at most 33% of medium-duty and 16% of heavy-duty travel in 2040. Given the additional potential to electrify these larger vehicles, the adoption of medium and heavy-duty PEVs could be significantly more important after 2040 and we recommend ongoing study of their electrification.
- **The cost and availability of direct air capture (DAC) and storage of CO_2 is a smaller uncertainty in these results.** DAC is a direct consumer of electricity, but it also changes the need for electrification in other sectors and reduces the strength of

policy required to achieve BC's targets, which may indirectly result in greater economic activity and electricity demand. Because these dynamics largely offset each other, DAC appears to have a limited impact on future electricity demand. However, this uncertainty could be larger: DAC could be deployed in an all-electric configuration (i.e. higher electricity demand in BC), or BC could fund DAC that occurs in another jurisdiction (i.e. lower electricity demand in BC) if these credits could be used as an offset to provincial GHG emissions.

- **Electricity demand through to 2040 is not sensitive to the production cost of 2nd generation biofuels or to more stringent building regulations.** A longer-term analysis, to 2050 for example, might find that these uncertainties become more important.

Summary Figure 2: British Columbia electricity demand in the stronger policy scenario with high/low range (note that the vertical axis starts at 50 TWh)



Note that **this analysis did not assess the impact of uncertainty in future natural gas production on electricity demand.** Including this dynamic would introduce more uncertainty into the electricity demand forecast. Based on the quantity of electricity used by the natural gas sector, this uncertainty could be at least as important to future electricity demand as is the uncertainty in PEV costs.

In summary, **this analysis shows that achieving BC's GHG reduction targets will result in substantially more electricity demand than would occur with current policies.** The results do not show a future where other potential low-GHG energy pathways out-compete electricity. Rather, these pathways, including bioenergy, energy efficiency and some use of hydrogen fuel cell vehicles, are complementary and all contribute to deep GHG reductions.

Table of Contents

1. Introduction

The greenhouse gas (GHG) reduction policies implemented by the government of British Columbia and the Government of Canada will change the quantity and type of energy consumed in British Columbia (BC) in the future. Specifically, GHG reduction policy may result in significant electrification of some energy end-uses, allowing the substitution of fossil fuels with renewable energy (e.g. wind, hydro, solar power), delivered via the electricity system. Electricity consumption may increase for end-uses where that fuel is not currently widely used, such as transportation, or where there is significant share of other fuel fuels consumed, such as building space- and water-heating.

This potential change in electricity consumption is of interest to BC Hydro. Understanding the drivers of energy consumption will help with the utility's electricity system planning. The extent of electrification is largely a function of electric technology capital and energy costs compared with the cost of the conventional and alternative fuels that may compete or complement the use of electricity in a low-GHG future. A further uncertainty is the design of the policy portfolios that will drive a reduction in GHG and emissions and may directly or indirectly require the use of low-carbon electricity.

The goal of this project is to analyse the uncertainty in future electricity demand created by current and potential energy and GHG policies as well as the cost and performance of emerging energy technologies whose adoption will be incentivized by these policies. In doing so, this analysis will provide reasonable bookends for future electricity consumption in BC, while explaining the drivers of this consumption (e.g. technology market shares, fuel shares by sector, use of alternatives e.g. biofuels).

While this is a forecast of electricity consumption in BC, it is independent of the BC Hydro load forecast. Nonetheless, within this analysis, the forecast of electricity consumption in the absence of new GHG policies has been approximately aligned with BC Hydro's 2020 December Reference load forecast to facilitate a comparison between the two. Similarly, while this is an analysis of how provincial GHG reduction policies will affect energy consumption and GHG emissions in the province, it is independent of the work the BC government has done in this regard. For example, this analysis uses a generic emission cap to achieve the provincial GHG targets in 2025, 2030, and 2040.

This report begins by describing the methodology, first with an overview of the energy-economy model used to produce the quantitative forecasts used in this analysis, which runs from the present to 2040. The methodology section then goes on to explain the scenarios we tested with that model. The scenarios include a forecast of provincial energy consumption and GHG emissions under the influence of currently legislated GHG reduction policies which is compared against a scenario with stronger GHG reduction policies that will achieve BC's legislated emissions targets for 2025, 2030 and 2040. Variations of this policy scenario are compared against each other to understand how future electricity consumption is affected by the use of technology neutral versus prescriptive policies, lower-cost electric vehicles, and higher cost biofuels. After the methodology section, we present and explain the scenarios results. This is followed by summary discussion of the key results and conclusions stemming form this analysis. The appendices include the detailed technology and fuel research conducted for this analysis and greater detail on the archetypal building energy technologies (e.g. building envelopes, mechanical systems etc.).

2. Methodology

This section first qualitatively describes gTech, the energy-economy model used for this analysis. This is followed by a description of the fundamental inputs to gTech as well as key indicators that describe the future forecasted by gTech. The methodology also includes an overview of the scenario design for this analysis as well as the specific GHG policy scenarios and uncertain parameters that are tested in these scenarios.

2.1. Introduction to the gTech model

The gTech model is designed to simulate the impacts of policy on both technological adoption and the broader economy. It simultaneously combines an explicit representation of technologies (everything from vehicles to fridges to natural gas extraction technologies) with key economic transactions within an economy, allowing it to provide insight about policy impacts on broader economic indicators such as GDP, industrial competitiveness and household welfare. This framework differs from most other models, which either exclude explicit technologies or are not intended to simulate full economic impacts.

Some of gTech's key features are highlighted below:

- **Over 50 unique energy end-uses and 200 unique technologies available to meet the end-use demand in all sectors of the economy.** For example, the model accounts for (1) the electricity consumption and hot water demand for different archetypes of clothes washers, (2) how changing the stock of clothes washers influences the demand for hot water and (3) the energy consumption of hot water heaters.
- **An explicit simulation of technology choice and capital stock turnover.** Each technology/end-use has a unique lifespan. The existing stock of technologies gradually retires over time, leaving a gap between the demand for end-use services and the supply from existing technologies. This gap is filled with new stock. New stock is determined using a technology choice algorithm that allocates market share to new technologies based on (1) capital costs, (2) energy costs, (3) discount rates, (4) an elasticity that accounts for heterogeneous decision-making among consumers and (5) non-financial factors that influence technology choice.
- **Technology choice in gTech is behaviourally realistic as opposed to prescriptive.** gTech seeks to be "descriptive", meaning that it tries to forecast how households and firms will respond to energy/climate policy or to changes in economic

conditions (e.g., change in the price for natural gas). Models that are “prescriptive” seek to tell the user the best path towards achieving a specific objective, with a typical objective being to minimize financial costs. While prescriptive models serve a purpose, they are not forecasting tools. The reason is that households and firms do not use financial costs as their only criteria for selecting technologies; rather, they use a myriad of criteria of which financial costs are just one consideration.

- **gTech has comprehensive coverage of energy consumption and energy-related GHG emissions in British Columbia.** The model aligns with Statistics Canada energy use data and the British Columbian provincial by economic sector and inventory category.

- **gTech is simultaneously a full economic model, in addition to a bottom-up technology model.** gTech is classified as a “computable general equilibrium” or CGE model. In a nutshell, gTech simulates:

  - **70 sectors of the economy.**

  - **10 regions.** The version of the model used for this project explicitly simulates the economies of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Québec, New Brunswick, Nova Scotia, and the “rest of Canada” (i.e., Newfoundland, PEI and the territories) and the United States.

  - **The markets for commodities, factors and policy mechanisms in every region of the model.** gTech ensures that ALL markets simulated within the model arrive at an equilibrium. Equilibrium is defined as supply being equal to demand. gTech ensures equilibrium in all the following markets:

    - Over 78 commodity and service markets. These commodity and service markets include everything from energy products (e.g., oil, refined petroleum products, petroleum coke, electricity); resource commodities (e.g., wheat, soy, corn); manufactured goods (e.g., petrochemicals, cement); and services (e.g., trucking transport, wholesaling/retailing margins, other services).

    - Factors markets, including four different classes of labor based on productivity and capital goods.

    - Policy compliance mechanisms. Some policies generate a market for compliance mechanisms (e.g., allowances under a cap-and-trade program or credits under a low-carbon fuel standard). Under these policies, the allowances distributed, auctioned or purchased must equal the allowances required by the entities participating in the market. In gTech, the price for these policy compliance mechanisms adjusts to achieve equilibrium in these policy markets.

- gTech can simulate how:
  - **Policies affect the economy.** gTech reports economic impacts on both expenditure- and income-based GDP. The former reflects impacts on consumption, investment, government expenditures and exports and imports, while the latter reports impacts on GDP produced by each of the 70 sectors in the model.
  - **Policies affect industrial competitiveness.** As an economic model, gTech explicitly simulates how policies affect industrial competitiveness. For example, if the cost of products and services increases in Nova Scotia but not in other jurisdictions, demand for Nova Scotia's products and services will fall.
  - **Policies in jurisdictions outside of BC affect the province.** Policies implemented outside of BC may have an impact on the province (e.g. the federal vehicle emissions standards or carbon pricing).
- **gTech contains an electricity supply cost curve that has been calibrated to information provided by BC Hydro:** This cost curve shows an increasing average production cost (in real terms) for electricity as demand grow relative to current levels. There are limitations on the functional forms that can be used in gTech, so the cost curve does not replicate the information provided by BC Hydro exactly for large changes in electricity demand, for example a doubling of current demand. In this case, model is conservative in showing somewhat higher electricity costs and prices.

2.2. Fundamental drivers and reference scenario indicators

Fundamental inputs to gTech include forecasts of economic activity, oil and gas commodity prices, and specific assumptions for activity in the liquefied natural gas (LNG) sector (Table 1).

GDP growth in BC is based on the Parliamentary Budget Office's Fiscal Sustainability Report[1]. This long-term forecast average about 1.5% after 2020 and does not explicitly account for any ongoing impact of COVID-19 on the economy. Population growth can

[1] Parliamentary Budget Office, 2020 Fiscal Sustainability Report. Available from: https://www.pbo-dpb.gc.ca/en/blog/news/RP-1920-029-S-fiscal-sustainability-report-2020-rapport-viabilite-financiere-2020

be approximated by the labour growth contained within the GDP assumption which averages about 0.7%/yr over the forecast (Table 1).

The price of crude oil is based on the reference projection by the Canada Energy Regulator (CER)[2] with a long-term price of 70 USD/bbl (Table 1). Like GDP, this long-term forecast is not explicitly accounting for the impact of COVID-19. The price of natural gas is based on the same source, remaining low during the forecast, rising to just over 3 USD/mmbtu after 2030 (Table 1). This price is calibrated to the CER reference forecast by adjusting production costs assumption in the model rather than being a direct input.

Table 2 shows some key indicators that describe the future forecasted by gTech, including activity in the upstream natural gas sector, building floor area, housing starts and retail spending. These are modelled results that come from forecasting a continuation of current GHG reduction policies. The LNG production assumption is based on the 2020 reference load forecast.

Table 1: Fundamental drivers

	Unit	2015	2020	2025	2030	2035	2040
GDP growth	%/yr	n/a	2.42%	1.49%	1.40%	1.48%	1.55%
Labour growth	%/yr	n/a	1.30%	0.38%	0.52%	0.67%	0.77%
Natural gas price (Henry Hub)	2020 USD/mmbtu	2.4	2.1	2.5	3.0	3.2	3.4
Oil Price (WTI)	2020 USD/bbl	51	64	67	70	70	70

Table 2: Scenario indicators

	Unit	2015	2020	2025	2030	2035	2040
Natural gas production	bcf/day	4.1	5.4	7.9	9.1	9.3	9.3
Commercial and institutional floor area	Million m^2	102	119	127	137	149	161
Residential floor area	Million m^2	281	321	335	350	358	379
Housing starts*	New units/yr	33,683	40,918	21,149	21,759	18,252	29,742
Retail spending*	Billion 2020 CAD/yr	74	86	90	97	103	111

* Housing starts and retail spending are based on historic values indexed to growth in new residential floor area and activity in the wholesale and retail sector in gTech, respectively. The 2015 housing starts value is an average of 2013 to 2017.

[2] Canada Energy Regulator (2020). Canada's Energy Future 2020: Energy Supply and Demand Projections to 2050. Available from: www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2020/index.html

2.3. Scenario design and summary

This section explains the scenarios we tested in this analysis. These included several different policy scenarios based on current policies and stronger policies that can achieve BC's legislated GHG emission targets. Additional sensitivity scenarios explore the impact of varying technology assumptions that may lead to more or less electricity consumption in BC in a low-GHG future.

To test the impact of GHG reduction policies on electrification, we used three policy scenarios, summarized in Figure 1. The first is a representation of current legislated policies as well as firm policy announcements that are very likely to be implemented and are included in BC Hydro's load forecast (i.e. "current policies"). Of note, this scenario includes:

- A zero-emissions vehicle (ZEV) standard that requires sales of non-emitting light-duty vehicles (e.g. plug-in electric vehicles, PEVs, and fuel-cell electric vehicles). This policy is modelled directly from the legislation, where there is an annual requirement for ZEV sales credits each year and each ZEV sale produces credits as a function of its range.[3] While this policy could require 100% ZEV sales by 2040, the sale of longer range ZEVs generate more credits and could allow conventional car sales to continue to this date.

The second scenario include several incentive and regulatory policies paired with a hypothetical emissions cap that requires BC to achieve its s legislated GHG emissions targets: a 16% reduction in emissions from 2007 by 2025 (52 $MtCO_2$), a40% reduction by 2030 (37 $MtCO_2e$) and a 60% reduction by 2040 (25 $MtCO_2e$). Note that the 2030 target includes the assumption that 2 $MtCO_2e$ of forestry offsets will be available in that year so the actual emissions in the results will be 39 $MtCO_2e$. This is a somewhat ad hoc assumption that helps the model solve in 2030, though it is based on ideas

[3] Government of British Columbia (2020). ZERO-EMISSION VEHICLES REGULATION. www.bclaws.gov.bc.ca/civix/document/id/oic/oic_cur/0448_2020

expressed in the government's Forest Carbon Initiative[4] and analyses by Smyth et al. (2020)[5]. The incentives and regulatory policies include:

- A strengthening of the Renewable and Low-Carbon Fuel Requirement
- A ZEV standard that with some additional requirements for medium and heavy-duty vehicles
- A renewable natural gas (RNG) standard requiring a minimum blend of renewable fuel in the natural gas stream
- Incentives for the efficient electrification of buildings (e.g. with heatpumps)
- Requirement for building envelope energy retrofits from after 2030
- A zero-emissions building requirement, which affects new heating system installations after 2035

The final policy scenario is identical to the stronger policy scenario, except that excludes the additional building regulations (post-2030 retrofits and zero-GHG requirement).

Both stronger policy scenarios include more stringent GHG reduction policies in the rest of North America, added to mitigate "carbon leakage" where BC industrial activity declines and moves to other jurisdictions. Consequently, we assumed that in the stronger policy scenarios, GHG reduction policies outside of BC will be of a similar stringency to policies in BC. Specifically, the precent GHG reduction targets applied to BC were also applied to the rest of Canada and the United States for 2030 onwards.

The sensitivity analyses explore scenarios seven additional scenarios where different assumptions for technology cost, performance and availability might change future electricity demand (summarized in Figure 1):

- Lower and higher plug-in electric (PEV) vehicle costs, across all classes of vehicles
- Lower and higher 2nd generation bioenergy costs (for drop-in liquid and gaseous fuels made from woody or grassy feedstock)

---

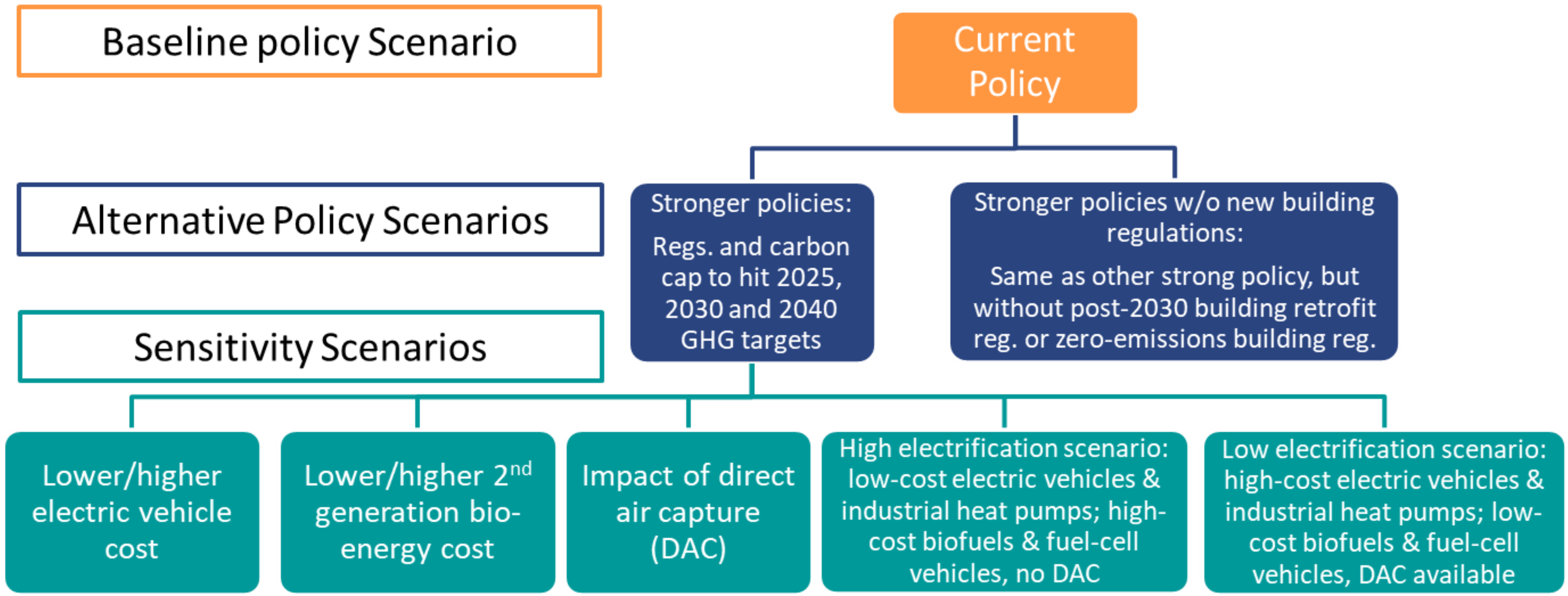
[4] Government of British Columbia. Forest Carbon Initiative. Available from www2.gov.bc.ca/gov/content/environment/natural-resource-stewardship/natural-resources-climate-change/natural-resources-climate-change-mitigation/forest-carbon-initiative

[5] Smyth, C.E.; Xu, Z.; Lemprière, T.C.; Kurz, W.A. (2020). Climate change mitigation in British Columbia's forest sector: GHG reductions, costs, and environmental impacts. Carbon Balance and Management, 15, 21. https://doi.org/10.1186/s13021-020-00155-2

- The availability of direct air capture (DAC) as a GHG abatement opportunity
- The combined impact of assumptions that are expected to lead to higher electrification: lower PEV costs and lower industrial heat pump costs, higher bioenergy costs and higher fuel-cell vehicle costs, no use of DAC.
- The combined impact of assumptions that are expected to lead to lower electrification: higher PEV costs and higher industrial heat pump costs, lower bioenergy costs and lower fuel-cell vehicle costs, DAC is used to reduce GHG emission.

Specific policy details by scenario are described in the next section (2.4). Specific sensitivity analysis assumptions are described in section 2.5.

Figure 1: Scenario Design Summary



2.4. Policy scenario inputs

Table 3 contains the detailed policy assumptions for each of the policy scenarios modelled in this analysis. Cells highlighted in green contain policy assumptions that are different from the previous column (i.e. the scenario to the left in the table).

Table 3: Detailed policy assumptions by scenario

Policy	1. Current policies - (no new policies except firm announcements)	2. Stronger policy scenario	3. Stronger policy scenario w. less building regulations
Carbon tax, price, or cap	\$50/tCO2e carbon tax (nominal) by 2022, with revenue recycled to cut labour taxes, provided as lump sum to households, and used to subsidize low-GHG industry	The same carbon tax as in the current policy scenario until 2030 with the use of GHG emission caps aligned with provincial GHG targets: -15% from 2007 in 2025; -40% in 2030, 37 Mt/CO2e ; -60% from 2007 in 2040, 25 Mt/CO2e	Same as 2
Clean Energy Act	98% renewable and zero-GHG electricity generation in 2030, 100% in 2040	Same as 1	Same as 1
Methane fugitive emission regulations	-	Oil and gas: ~45% reduction in fugitives for new equipment starting in 2020, with all equipment covered by 2025	Same as 2
Formation CO_2 carbon capture and storage	-	Capture and storage required for CO_2 removed from natural gas stream during processing	Same as 2
Renewable natural gas	-	15% by 2030	Same as 2
Landfill gas reductions	Organics diversion and landfill gas control: landfills reduce emissions by 35% by 2020, 30% of organic waste is diverted from landfills by 2025	75% of methane gas is captured from large landfills, 95% of organic waste is diverted from landfills by 2025	Same as 2

Policy	1. Current policies - (no new policies except firm announcements)	2. Stronger policy scenario	3. Stronger policy scenario w. less building regulations
Clean vehicle incentives	Existing Clean Energy Vehicles subsidy, ending in 2020	An additional $14 million per year until 2030 to incentivize the purchase of battery electric and plug-in hybrid vehicles. An additional $3.3 million per year until 2030 for zero emissions heavy-duty vehicles	Same as 2
Renewable and low-carbon fuel requirement	-10% GHG intensity by 2020	-20% GHG intensity by 2030, *not including electrification after 2021.*	Same as 2
Light-duty vehicle emission standards	119 gCO_2e/km fleet average for new sales by 2025 (approximately -40% relative to 2015)	105 gCO_2e/km by 2030, for which electric vehicles do not count as part of compliance	Same as 2
Light-duty zero-emissions vehicle (ZEV) mandate	Approximately 30% sales in 2030, and approaching 100% by 2040. Actual sales depend on the range of ZEVs that are sold (longer range allow less ZEV sales)	Same as 1	Same as 1
Heavy-duty vehicle emission standards	-10% reduction in of the GHG intensity for new vehicles from 2018 onward, relative to the 2015 model year vehicles	-24% in tailpipe CO_2 emissions for 2030 model year vehicles relative to 2015 model year vehicles	Same as 1
Medium and Heavy-duty vehicle ZEV mandate	-	Plug-in medium and heavy-duty vehicles: 10% sales by 2030 and beyond LNG-fueled vehicles: 16% sales in 2030 (no requirement thereafter)	Same as 2
Building codes for envelopes	Step code for new buildings, requiring net-zero ready after 2031	Same as 1	Same as 1
Heat Pump Incentive		$38 million annually through to 2030, used to incentivize the purchase of heat pumps for space and water heating	Same as 2

Policy	1. Current policies - (no new policies except firm announcements)	2. Stronger policy scenario	3. Stronger policy scenario w. less building regulations
Building envelope retrofits		Starting after 2030, 1.5%/yr of pre-2010 buildings are retrofitted to reduce heat load by 15-20%	Same as 1, no retrofit requirement
Zero-emissions building policy		Heat pumps are required for new/replacement space and water heating equipment after 2035	Same as 1, no zero-emissions requirement
North American policy outlook	No new policies (except firm announcements): Includes the federal carbon pricing backstop ($50/tCO2e carbon price equivalent (nominal) by 2022).	Stronger GHG policy is modelled as an emissions cap in the rest of the Canada and the US: The cap is equivalent to BC's in 2040 (-60% from 2007), but somewhat weaker when it starts in 2030 (-25% from 2007)	Same as 2

2.5. Sensitivity scenario inputs

The sensitivity scenario inputs below are all variations on the stronger policy scenario (scenario 2 in Table 3 above). The sensitivity analyses deal with:

- Lower and high PEV costs (across all classes of vehicles)
- Lower and high 2nd generation bioenergy costs (i.e. renewable gasoline, diesel, and natural gas produced from woody or grassy feedstock)
- The availability of direct air capture and storage of CO_2 (DAC)
- A combined look at assumptions that could lead to lower and higher electricity consumption: PEV and fuel-cell electric vehicle costs, 2nd generation bioenergy costs, industrial heat pump costs and the availability of DAC.

2.5.1. Plug-in electric vehicle cost sensitivity scenarios

The vehicle battery cost sensitivity scenarios affect the capital cost of all plug-in electric vehicle (PEV) technologies including light-duty vehicles, medium-duty vehicles, heavy-duty vehicles (represented archetypically as freight trucks) and buses.

PEV battery pack manufacturing costs are estimated at about 500 $/kWh (2020 CAD), backcasted based on the UBS bank's analysis of the Chevrolet Bolt.[6] The reference assumption is that battery costs may fall to $75/kWh (Table 4), based on Bloomberg New Energy Finance's 2020 outlook.[7] The higher cost assumption for a minimum cost of $105/kWh, is based on a 2017 outlook from BNEF.[8] The low cost assumption of $75/kWh is based on assumptions from the International Council on Clean Transportation (2019).[9]

The trajectory between the starting battery cost and the lowest cost is not assumed. Instead it is a function of the learning and the economies of scale that occur when the North American market for PEVs grows (assuming global production follows a similar trend). Therefore, the time when the lowest cost is reached is a model result rather than input, though it is included in Table 4 to illustrate how assumptions are affecting the scenario results.

Table 4: Battery pack manufacturing cost assumptions (2020 CAD/kWh)

	Starting cost (2015)	Lowest cost	Lowest cost reached:
Reference	$502	$84	After 2030
Low-cost	$502	$75	After 2030
High cost	$502	$105	After 2035

Battery manufacturing costs are only one component of total vehicle capital costs which include the cost of other components (e.g. vehicle glider, electronics, engine and transmission where applicable) and wholesale and retail markups (i.e. sales margins). Like batteries, many of these costs are function of the scale of PEV deployment. Therefore, vehicle costs throughout time are actually a model result. Nonetheless, these costs are included here to illustrate the effect of PEV cost model inputs. Table 5

6 UBS (2017). UBS Evidence Lab Electric Car Teardown – Disruption Ahead? UBS Evidence Lab, Global Research

7 Bloomberg New Energy Finance (2020). Electric Vehicle Outlook 2020.

8 Bloomberg New Energy Finance (2017). Electric Vehicle Outlook 2017.

9 International Council on Clean Transportation. (2019). Update on electric vehicle costs in the United States through 2030.

shows the light-duty vehicle retail prices for electric vehicles as a function of the sensitivity scenario, compared with the price assumptions for a conventional vehicle. Table 6 and Table 7 show those assumptions for medium-duty and heavy-duty vehicles. The development of vehicle prices as a function of potential battery pack manufacturing costs and other component costs is explained in detail in “Appendix A: Electrification Technology Research” as are energy intensity of the technology archetypes and rational for which technology archetypes are represented in the analysis.

Although, the focus of this section in on PEV costs, the model includes a range of other vehicle drivetrain archetypes. These include conventional vehicles of varying degrees of efficiency, hybrids (light-duty, buses, and medium-duty), and fuel cell-electric vehicles (FCEVs), compressed natural gas (buses and medium-duty) and liquefied natural gas (heavy-duty).

Table 5: Light duty-vehicle archetype capital costs by drivetrain and sensitivity scenario (based on sedan-sized vehicle, excluding any charging infrastructure) (2020 CAD)

	2020	2030	2040
Conventional high efficiency vehicle	22,923	22,923	22,923
Reference costs			
Plug-in hybrid (approx.64km)	33,729	27,451	26,962
Battery Electric (approx. 320 km)	39,072	24,680	23,162
Lower cost			
Plug-in hybrid (approx.64km)	32,942	26,771	26,182
Battery Electric (approx. 320 km)	38,141	23,433	21,594
Higher cost			
Plug-in hybrid (approx.64km)	29,649	28,928	28,810
Battery Electric (approx. 320 km)	39,932	28,306	26,885

Table 6: Medium-duty-vehicle archetype capital by drivetrain and sensitivity scenario (2020 CAD)

	2020	2030	2040
Diesel truck, high efficiency	75,439	75,439	75,439
Electric truck (approx. 200 km):			
Reference costs	105,825	72,085	68,320
Lower cost	104,094	69,321	64,759
Higher cost	107,423	79,852	76,641
Additional charge infrastructure			
Reference costs	49,822	49,380	37,293
Lower cost	49,822	49,158	24,584
Higher cost	49,822	49,463	46,227

Table 7: Heavy-duty-vehicle archetype capital costs by drivetrain and sensitivity scenario (based on class 8 freight truck) (2020 CAD)

	2020	2030	2040
Diesel truck, high efficiency	185,212	185,212	185,212
Electric truck (approx. 400 km):			
Reference costs	333,781	189,661	171,827
Lower cost	330,214	179,216	157,587
Higher cost	337,072	216,627	203,930
Additional charge infrastructure			
Reference costs	283,022	274,282	203,864
Lower cost	283,022	274,312	194,411
Higher cost	283,022	274,316	204,168

2.5.2. 2nd generation bioenergy cost sensitivity scenario

The bioenergy cost and potential sensitivity scenarios affect the price of all 2nd generation biofuels represented in gTech: cellulosic ethanol, renewable gasoline, diesel and natural gas, all of which have agricultural and forestry residue as feedstocks.

Biofuel costs

Given that 2nd generation biofuel plants are pre-commercial, their capital costs in the reference biofuel cost scenario are set at roughly 1.5 times the preliminary cost estimated found in the literature. In the pessimistic scenario, the capital costs are 25% than the reference costs, while in the optimistic low-cost scenario the capital cost is 25% lower. The resulting capital costs and wholesale fuel costs (net of any distribution margins or taxes) are in Table 8. For context, the wholesale price of gasoline and diesel have generally been between $0.60/L and $0.80/L over the past decade while the wholesale price of fossil natural gas has been in the range of $3/GJ. The characterization of 2nd generation biofuels in this analysis are explained in greater detail in "Appendix A: Electrification Technology Research".

Table 8: 2nd generation biofuel plant capital costs and production costs by sensitivity scenario (2015 CAD)

	Wholesale fuel cost (not including margins and taxes, long-term 2030-2040)
Reference Assumptions	
Renewable gasoline and diesel	$1.04/L
Renewable natural gas	$18/GJ
High Cost Assumptions	
Renewable gasoline and diesel	$1.16/L
Renewable natural gas	$21/GJ
Low Cost Assumptions	
Renewable gasoline and diesel	$0.9/L
Renewable natural gas	$15/GJ

Residue for 2nd generation biofuel feedstock

The reference assumption for the maximum residue available in Canada is 34 million oven dry tonnes per year (ODt/yr) based 2010 activity in the agricultural and forestry sectors (Table 9). This quantity includes roadside forest harvest residue and the crop residue produced for corn and grain production, not already used for other purposes (roughly 25% available, with the rest primarily left it in the field for soil sustainability).

The reference assumption does not include any urban wood waste, surplus wood waste from forest products mills (i.e. not used internally for energy), or purposely grown energy crops. Further detail on this quantity is explained in "Appendix A: Electrification Technology Research". To put this quantity in context, if the feedstock were converted to renewable gasoline and diesel (18 GJ/ODt at 63% energy conversion efficiency from feedstock), they could replace 15% of 2010 Canadian gasoline and diesel consumption. As well, the model includes the U.S. which can trade in residue and biofuels with Canada. Finally, first generation biofuels are and remain available in the model, where their production is constrained by a limited pool of land and crop prices.

Table 9: 2nd generation bioenergy feedstock availability (based on 2010 activity in the forestry and agriculture sector)

	Forestry residue (million ODt/yr)	Agriculture residue (million ODt/yr)	Total (million ODt/yr)
Reference	15.7	18.2	34.0

2.5.3. DAC availability

In the scenarios where DAC is available, the cost starts at $370 per tonne of CO_{2e} removed from the atmosphere during early commercialization. The costs may decline as experience with the technology increases to a price floor of $150/t$CO_{2e}$ (2020 CAD). In practice, this forecast shows costs declining to $325/t$CO_2$ by the end of the analysis in 2040. The technology archetype represented in the model uses natural gas combustion to provide the heat required to regenerate the sorbent that captures the CO_2, where the combustion emissions are also captured and stored. The DAC process uses about 0.28 MWh/tCO_2 of electricity to move air and compress and transport CO_2 and another 4 GH of natural gas for process heat (about 0.35 MWh/tCO_2 and 5 GJ/tCO_2 avoided since some of the captured gas comes from natural gas combustion). Costs and energy intensity are based on Faishi et al. (2019)[10] and Keith et al. (2018).[11] "Appendix A:Electrification Technology Research" contains more details on this technology and how it is parameterized in this analysis.

2.5.4. Low and high electrification scenarios

The high electrification scenario includes the low-cost PEV assumptions, the high-cost bioenergy assumptions and has no DAC available. Additionally, it includes more

---

[10] Fasihi et al. (2019). Techno-economic assessment of CO_2 direct air capture plants. *Journal of Cleaner Production*. 224. doi.org/10.1016/j.jclepro.2019.03.086

[11] Keith et al. (2018). A process for capturing CO_2 from the atmosphere. *Joule*. 2, 8. doi.org/10.1016/j.joule.2018.05.006

pessimistic assumptions for hydrogen consumption (Table 10) and lower-cost assumptions for industrial heat pumps (a minor assumption; +12.5% capital cost, where the reference cost is about $1000/kW (2020 CAD), or 3 times the cost of a gas-fired boiler or heater).

In contrast, the low electrification scenario has DAC as a GHG abatement action and includes the high-cost PEV assumptions, the low-cost bioenergy assumptions and the more optimistic assumptions for hydrogen consumption (Table 10). This scenario also has higher cost assumptions for industrial heat pumps (again, a minor assumption; -12.5% capital cost relative to the reference).

Table 10: Additional hydrogen and FCEV assumptions for the low and high electrification scenarios (as well as reference assumptions for other scenarios)

Assumption	High electrification scenario assumptions	Low electrification scenario assumptions	Reference Assumptions	Source
Cost of hydrogen electric vehicles	**High cost:** Fuel cell stacks and hydrogen tank costs may decline to $125/kW and $28/kWh, respectively. Fuel cell vehicles remain substantially more costly than other vehicle types.	**Low cost:** Steeper cost declines are assumed. Fuel cell stacks and hydrogen tank costs may decline to $39/kW and $9.9/kWh, respectively Light-duty vehicle purchase price can decline to be on par with conventional and electric vehicles ***if*** the scale of production grows big enough.	**Moderate cost:** Fuel cell stack system costs may decline from $306/kW to a minimum of $74/kW ($31/kWh to a minimum of $11/kWh for fuel tanks). Light-duty vehicle purchase price still $1000's higher than conventional vehicle in the long-term. The technology is more promising for heavy-duty vehicles.	SA Consultants (2016). Final report: Hydrogen storage system cost analysis. SA Consultants (2017). Mass production cost estimation of direct H2 PEM fuel cell systems for transportation applications. IEA (2020). Breakdown of cost-reduction potential for electrochemical devices by component category.
Cost of hydrogen production	**High cost:** Capital costs are about 25% to 35% higher, zero-GHG hydrogen production costs are in the range of 10-11 $/kg.	**Low cost:** Capital costs are about 25% lower, zero-GHG hydrogen production costs are in the range of 6-9 $/kg.	**Moderate cost:** Zero-GHG hydrogen produced from biomass gasification and electrolysis costs in the range of 8-10 $/kg.	NREL (2019). H2A Hydrogen Production Analysis. IEA (2019). The Future of Hydrogen.
Hydrogen blending limit	**Low blending:** Hydrogen can be blended into the natural gas stream to 2% by volume (0.5% by energy content).	**High blending:** Hydrogen can be blended into the natural gas stream to 20% by volume (5% by energy content).	**Moderate blending:** Hydrogen can be blended into the natural gas stream to 5% by volume (1.3% by energy content)	International Energy Agency. (2019). The Future of Hydrogen Atfeld K., Pinchbeck D. (2013). Admissible Hydrogen Concentrations in Natural Gas Systems. European Gas Research Group. National Research Council Canada (2017). Review of hydrogen tolerance of key Power-to-Gas (P2G) components and systems in Canada: final report.

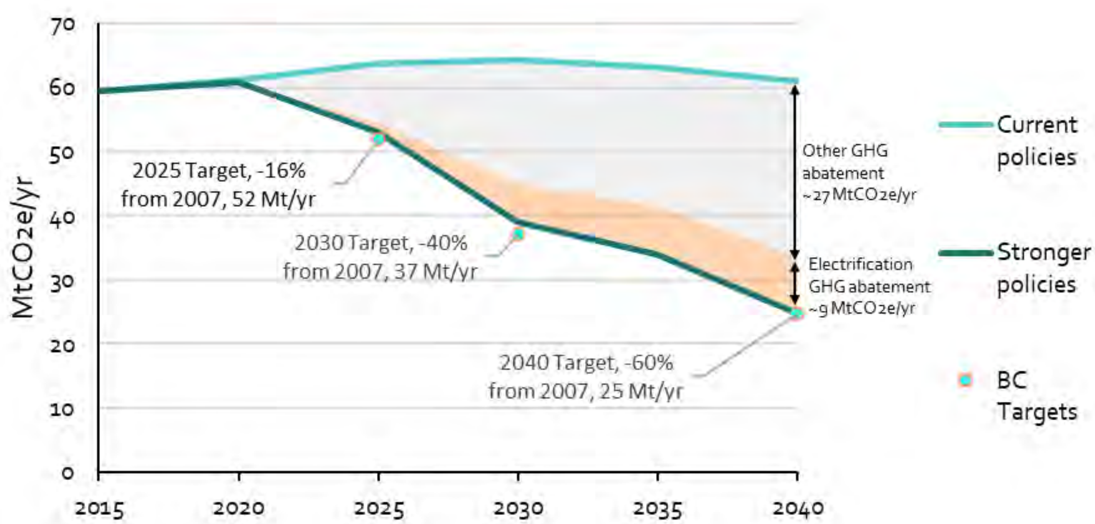
3. Results

The results chapter beings with a comparison of GHG emissions and electricity demand in the current policy scenario and the stronger policy scenario that achieves BC's GHG emissions targets. This is followed by explanatory results that describe the change in electricity demand in the stronger policy scenario in greater detail. The remaining section of this chapter assesses the sensitivity of this electricity demand forecast to a range of different technology assumptions and less prescriptive post-2030 building regulations (i.e. no retrofit or zero-GHG building regulation).

3.1. The impact of current and stronger GHG reduction policies

The implementation of stronger policies substantially reduces British Columbia's total GHG emissions from the present and relative to a scenario with current policies. Electrification is an important GHG abatement action. With currently legislated policies, provincial GHG emissions are kept roughly constant to 2040, despite a growing population and economy. By design, the stronger policy scenario achieves the legislated GHG targets in 2025, 2030 and 2040 (Figure 2). Recall that we assume 2 $MtCO_2e$ of forestry carbon offsets are available in 2030, but are not explicitly modelled. Therefore the results show that emissions in that year are 39 $MtCO_2e$ rather than 37. By 2040, electrification accounts for 25% of GHG abatement relative to the current policy scenario (about 9 of 36 $MtCO_2e$).

Figure 2: BC GHG emissions by scenario and breakdown of GHG abatement



*Provincial GHG emissions and targets exclude emissions resulting from international aviation and marine travel.

Stronger GHG reduction policies increase electricity demand in British Columbia. With current policies, future provincial electricity consumption matches the overall trend in load growth from the 2020 BC Hydro load forecast. There are differences by sector that cause a divergence in the forecasts around 2030 but total electricity demand in 2040 reaches roughly 71 TWh/yr in both the load forecast and the current policy scenario. The stronger policies increase electricity consumption relative to this baseline, initially by just over 1 TWh/yr in 2025, but with the difference growing to 10 TWh/yr in 2030 and 12 TWh/yr in 2040 (equivalent to +17% relative to the current policy scenario in that year) (Figure 3 and Table 11).

Figure 3: British Columbia electricity demand by scenario

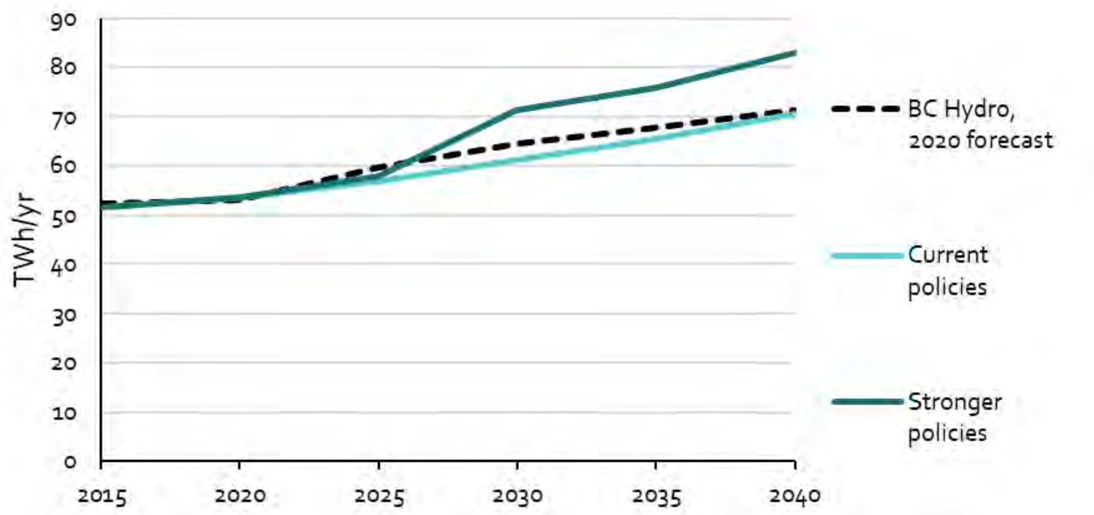


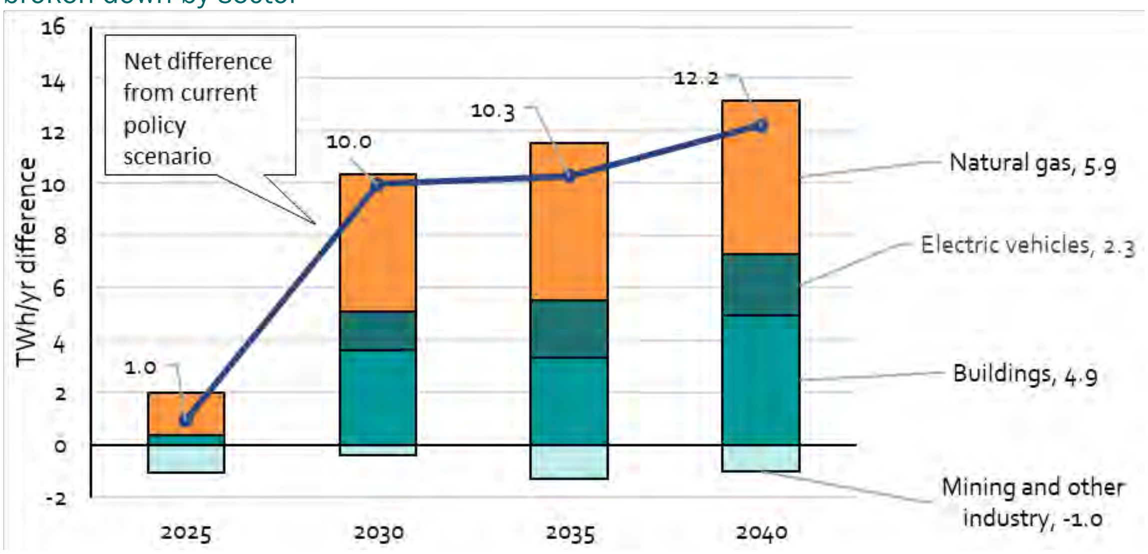
Table 11: British Columbia electricity demand by scenario (TWh/yr)

	2015	2020	2025	2030	2035	2040
BC Hydro, 2020 forecast	52.3	53.1	59.7	64.4	67.8	71.3
Current policies	51.4	53.5	56.9	61.3	65.5	70.7
Stronger policies	51.4	53.5	57.9	71.3	75.8	82.9

*Demand exclude electricity consumption for aluminum production and electricity consumed from cogeneration in forest products sectors, where this demand is supplied by industry owned generation.

Stronger GHG reduction policies result in much greater electricity demand relative to current policies, with the greatest differences in 2040 coming from the natural gas sector and buildings. To reach the legislated provincial GHG targets, both sectors must substitute even more electricity consumption for natural gas consumption. As such, the incremental electricity demand for gas compression and transport in the natural gas sector, relative to the current policy scenario, rises to about 5 TWh in 2030 and almost 6 TWh in 2040 (Figure 4). Similarly, additional electricity demand from buildings for space and water heating reaches almost 5 TWh by 2040. Incremental electricity demand from all classes of electric vehicles (light, medium and heavy-duty, including buses) is smaller because the current policy scenario already includes a significant amount of electrification driven by the light-duty vehicle ZEV standard. In contrast, slower economic growth results in somewhat less industrial and mining activity and less electricity demand. However, this reduction in industrial electricity demand, relative to the baseline, is a minor offset to the incremental load growth required to achieve provincial GHG targets.

Figure 4: Difference in electricity demand, stronger policies versus current policies, broken down by sector



3.2. Explanatory results for electricity demand in the stronger policy scenario

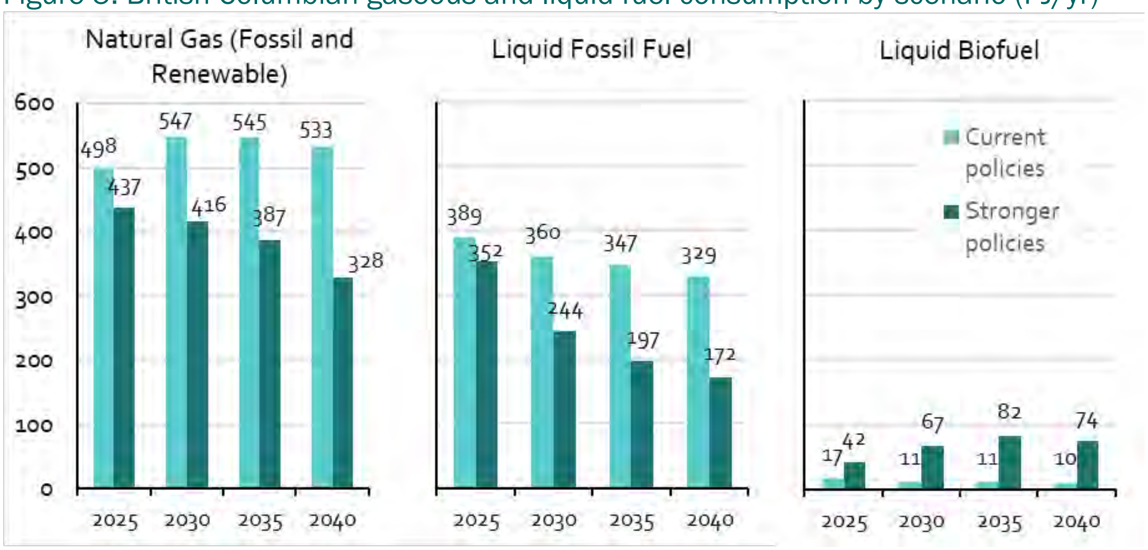
This section of the report goes into greater detail to explain the growth in electricity consumption required to achieve BC's GHG emissions targets. The details include an analysis of changes in other fuel consumption (e.g. gaseous and liquid fuels), changes in technology market shares (e.g. electric vs. non-electric technologies) and changes in activity and energy consumption by end-use in the relevant sectors.

3.2.1. Fuel Shares

Increased electricity demand occurs in response to GHG reduction policies when electricity, produced from low-GHG sources, is substituted for fossil fuels such as natural gas, gasoline and diesel.

The electrification that occurs in response to the strong policies results in substantially less liquid and gaseous fuel consumption by 2040, even when including biofuels. With current policies, gaseous fuel consumption (including what is used upstream by the natural gas sector) is about 25% larger in 2040 than it is in 2020 and all of that fuel consumption is fossil natural gas. In contrast, with strong policies, gaseous fuel consumption, which at minimum 15% renewable natural gas, declines by 25% relative to 2020 (Figure 5). Similarly, liquid fuel consumption declines relative to the current policy scenario to just 246 PJ/yr (fossil+biofuel), where one third of that is biofuel, much of it “drop-in” renewable diesel.

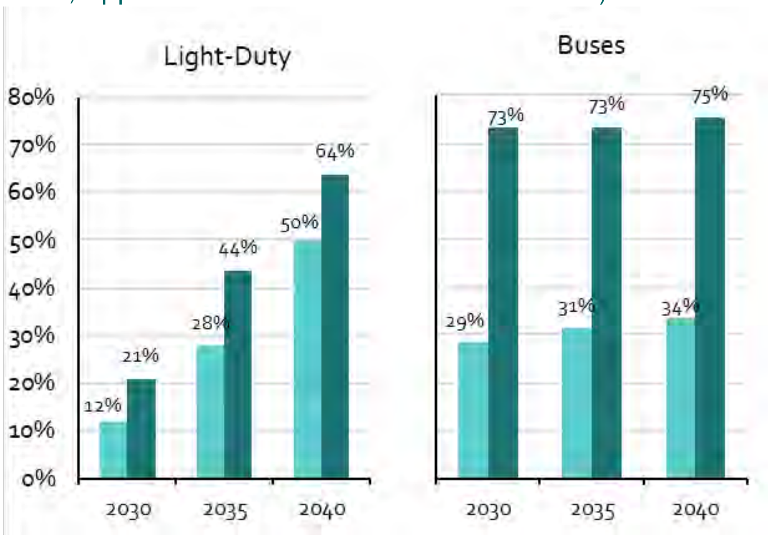
Figure 5: British Columbian gaseous and liquid fuel consumption by scenario (PJ/yr)



3.2.2. Transportation

The reduction in liquid fuel consumption and the increase in electricity consumption for transportation are both drive by the adoption of plug-in electric vehicles across all classes of on-road vehicles. In the current policy scenario, it is the light-duty ZEV standard is driving greater adoption of PEVs. However, this trend is accelerated to achieve provincial GHG targets in the stronger policy scenario where almost 50% of light-duty vehicles on the road are electric in 2035, reaching almost 65% in 2040 (Figure 6). This is equivalent to about 750,000 electric vehicles on the road in 2030 and 2.5 million in 2040.[12] Likewise, the switch to electric buses is also accelerated in the stronger policy scenario. After 2030, roughly 75% of buses are electric (vs. one third in the current policy scenario) (Figure 6). This is roughly equivalent to 12,000 transit, school and private electric buses operating in BC.[13]

Figure 6: Light-duty and bus PEV total market share by scenario (% of total travel by PEVs, approximates % of vehicles on the road)



There are also substantially more medium and heavy-duty ZEVs on the road in the stronger policy scenario. For medium-duty vehicles, most of these ZEVs are electric. The share of medium-duty travel activity using electric vehicles rises from about 12% in 2030 to 30% by 2040 (Figure 7Figure 6). Because the utilization and duty-cycles of medium duty vehicles is heterogeneous, it is difficult to equate this market share with a specific number of vehicles. However, Statistics Canada data indicates that there were approximately 135,000 medium-duty vehicles in BC in 2019[14] and that sector grows by 14% between 2020 and 2040 in the forecast. This market share and growth rate imply about 46,000 electric medium-duty vehicles on the road in 2040.

Heavy-duty ZEVs account for about 10% of travel activity in 2030, independent of the GHG policies are implemented. However, by 2040, this share rises to 24% with stronger policies. Heavy-duty ZEVs are a mix of both battery and fuel-cell electric

---

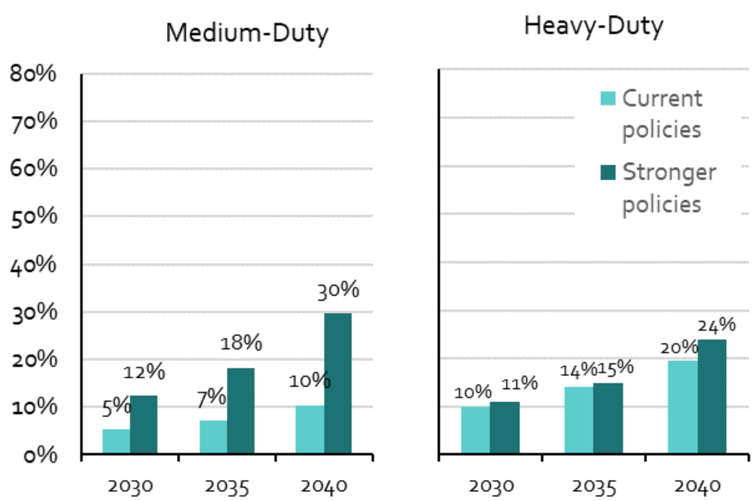
[12] Assuming 15,000 vehicle kilometers travelled per year by each light-duty vehicle

[13] Assuming 65,000 vehicle kilometers travelled per year by each bus with an average ridership of 12 passengers per km

[14] Statistics Canada. Table 23-10-0067-01 Vehicle registrations, by type of vehicle

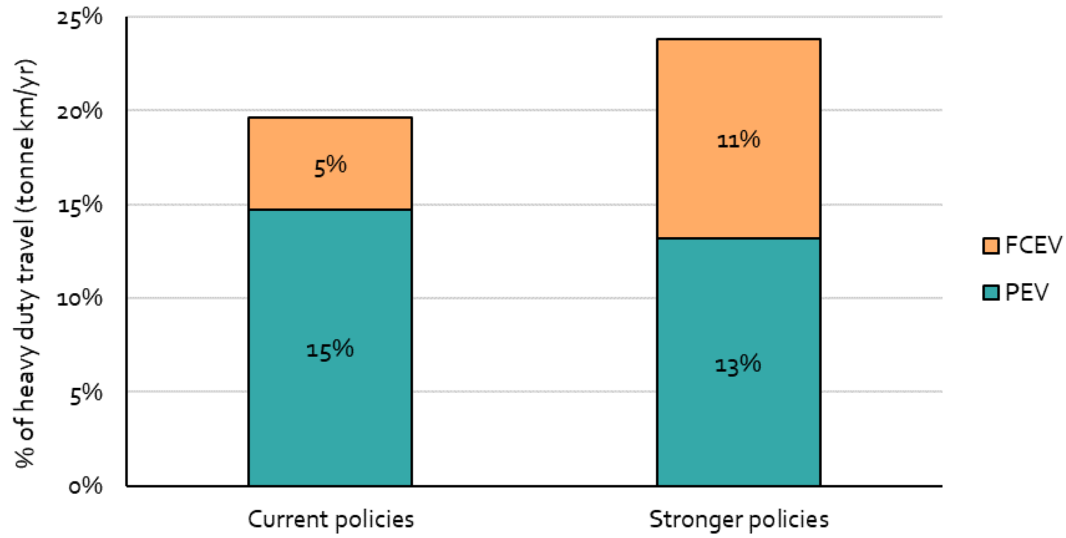
vehicles, where the relative share of each is sensitive to the GHG policy environment. Strong GHG reduction policies implemented across North America create a larger market for fuel-cell electric heavy-duty vehicles which in turn lowers their costs through economies of scale and learning. Consequently, there are more fuel-cell electric vehicles on the road in the stronger policy scenario. There is some competition between these two drivetrains and consequently there are fewer battery electric heavy-duty vehicles (Figure 8, 13% total market share compared to 15% in the current policy scenario). The utilization duty-cycles of heavy duty vehicles are also very heterogeneous, so calculating vehicles on-the-road from the modelled market share result is only a roughly approximation. Nonetheless, the stronger policy scenario indicates there would be about 5,500 battery electric heavy-duty vehicles on the road in 2030, and 12,000 in 2040.[15]

Figure 7: Medium-duty and Heavy-duty **ZEV** (electric ***and*** fuel cell vehicles) total market share (% of total travel activity by ZEVs)



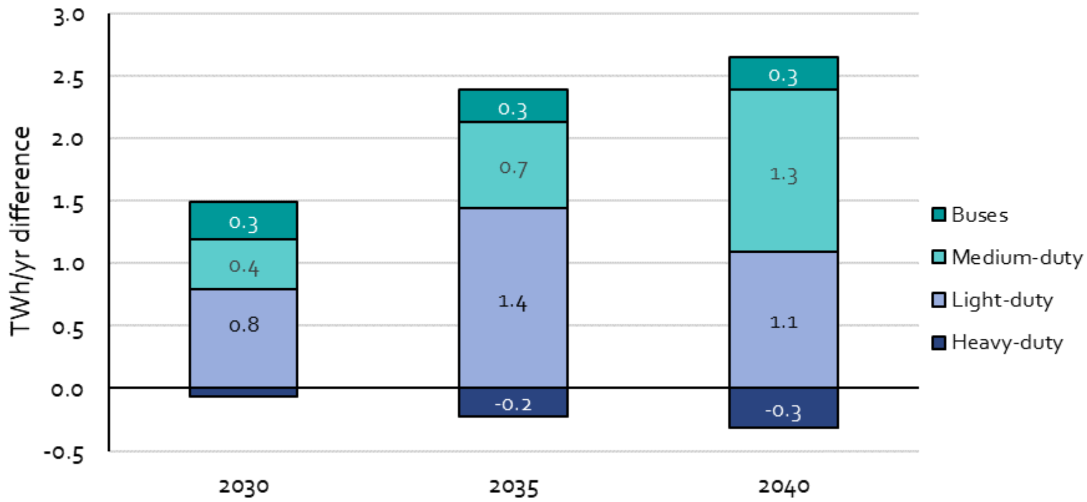
[15] Assuming each truck has an average payload of 10 tonnes, travelling 60,000 km/yr

Figure 8: Heavy-duty ZEV total market share by drivetrain type in 2040



By 2040, about half of the incremental electricity demand from transportation that occurs in response to stronger policies comes from medium-duty vehicles. Because the baseline current policy scenarios already includes a strong ZEV standard applied to light-duty vehicles, it already has substantial load-growth from these vehicles. As well. there are also fewer battery-electric heavy-duty vehicles in the stronger policy scenario (and more fuel-cell electric vehicles), hence less electricity consumption from those vehicles. In total, incremental electricity demand for transportation, relative to the current policy scenario, is 1.4 TWh/yr in 2030 (of which about 30% is from medium-duty vehicles). By 2040, the incremental load is 2.3 TWh/yr (of which about 50% is from medium-duty vehicles) (Figure 9).

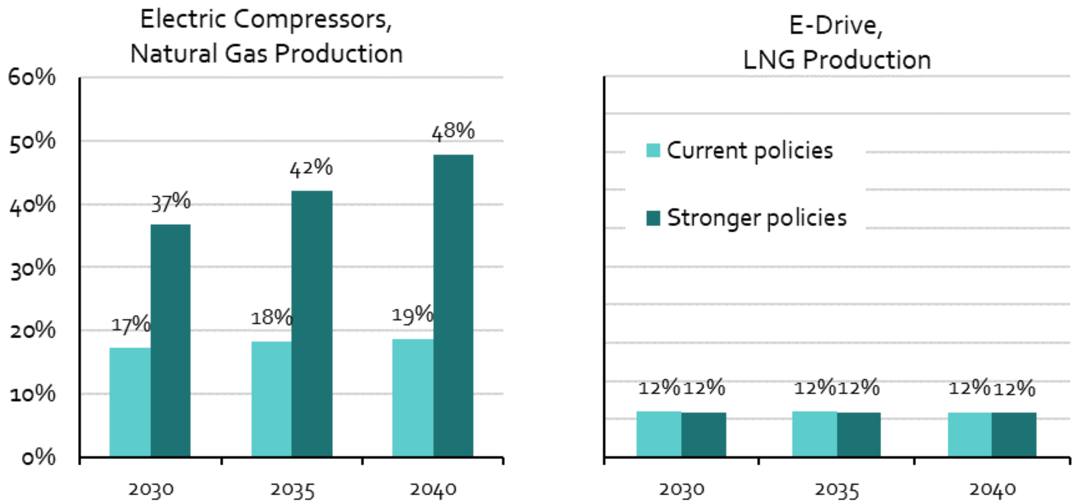
Figure 9: Incremental electricity demand from plug-in electric vehicles, stronger policies versus current policies, broken down by vehicle type



3.2.3. Natural gas

The change in electricity demand from the natural gas sector is largely a function of the adoption of electric compressors to transport natural gas. The stronger policies have no impact on electricity demand from the LNG sector within the time-horizon of this analysis. Electric compressors are used in place of gas-fired compressors, thus increasing electricity demand and reducing combustion GHG emissions. With stronger GHG policies, the incremental electricity demand from the natural gas sector, relative to the current policy scenario, grows from roughly 1.5 TWh/yr in 2025 to 6 TWh/yr in 2040 (total demand is roughly 7 and 11 TWh/yr in those years, respectively). The fraction of electric compressors is 37% in 2030 and almost 50% in 2040 (Figure 10). In contrast, the stronger policies have no impact on the drive technologies used for liquefaction in the LNG sector within the time horizon of this analysis (Figure 10).

Figure 10: Technology market share, % of natural gas and LNG production electrified by scenario



Reductions in natural gas production create a small offset to electrification. LNG production is not affected by GHG policies. The implementation of strong GHG reduction policies, which apply across all regions of North America (i.e. what is included in the model) suppresses demand for natural gas. Consequently, gas production in BC is somewhat lower in the stronger policy scenario, notably in 2040 when production is about 12%, or 1.1 bcf/day, lower (Table 12). Accordingly, electricity demand from the natural gas sector is slightly lower than it otherwise would be. However, it is important to note that the modelling includes some constraints that prevent a further reduction in natural gas production in BC and the corresponding reduction in the sector's electricity demand. Notably, we have assumed a fixed quantity of foreign demand for North American LNG, where 60% of the gas exported from BC must be produced in BC. If LNG demand were also reduced global GHG policies, then the activity and electricity demand in the BC natural gas and LNG sectors could be more sensitive to GHG policy than indicated in this analysis.

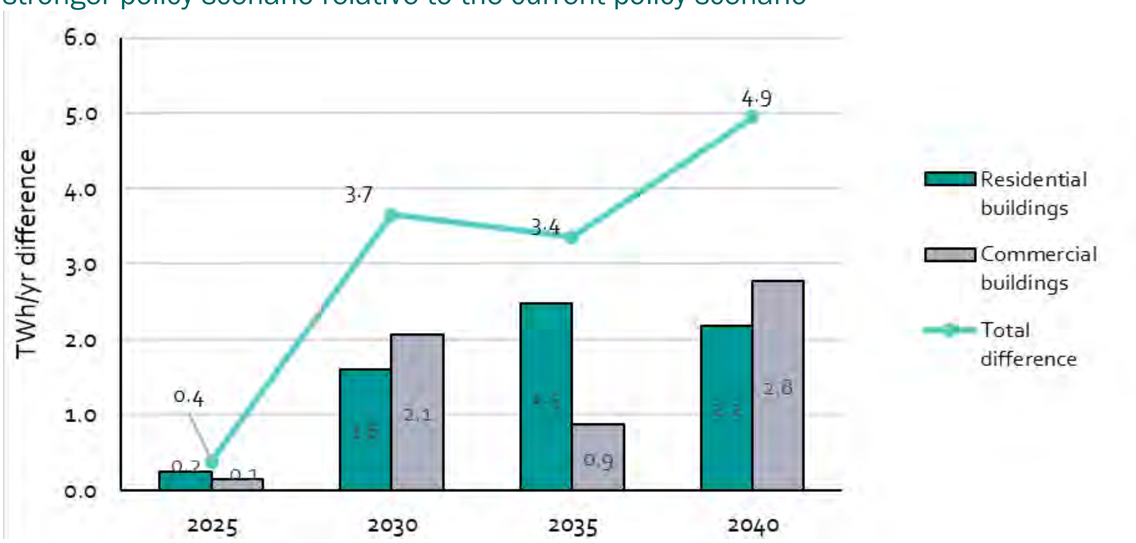
Table 12: Natural gas and LNG production in British Columbia by scenario

	2015	2020	2025	2030	2035	2040
Natural gas, bcf/day						
Current policies	4.1	5.4	7.9	9.1	9.3	9.3
Stronger policies	4.1	5.4	7.4	9.2	9.1	8.2
LNG gas, Mt/yr						
Current policies	0.0	0.0	8.4	19.0	19.0	19.0
Stronger policies	0.0	0.0	7.5	19.0	19.0	19.0

3.2.4. Buildings

Incremental electricity demand from buildings occurs in both residential and commercial/institutional buildings. With stronger GHG policies, the incremental electricity demand for buildings, relative to the current policy scenario, grows to about 3.5 TWh/yr for 2030 through to 2035, reaching almost 5 TWh/yr by 2040 (total demand is roughly 40 TWh/yr in 2030 and 44 TWh/yr in 2040) (Figure 11). The incremental demand from both commercial and residential buildings fluctuates over time depending on relative rates of electrification with current policies versus stronger GHG reduction policies.

Figure 11: Difference in building electricity consumption by building type in the stronger policy scenario relative to the current policy scenario



In response to stronger GHG reduction policies, there is a significant adoption of heat pumps for space heating in larger buildings (i.e. commercial) by 2030. By 2040, heat pumps are trending towards being a dominant space and water heating technology in

all BC buildings. Adoption of heat pumps through 2035 is a function of technology and energy costs (inclusive of carbon pricing) as well as some early incentives for heat pumps. This is most noticeable in commercial buildings starting in 2030, where the share of space heating provided by heat pump is over 50% (3x more than with current policies, Figure 13). After 2035, the adoption of heat pumps is further driven by the zero-emissions building policy, which requires new and replacement mechanical systems to use this technology. By 2040, 24% of residential space heating and 67% of commercial space heating is produced with heat pumps. There is a similar market penetration of heat pump water heating. Note that the model does not represent the potential for low-GHG biomass heating in commercial and institutional buildings, either through standalone systems or delivered by district energy. Therefore, the results may overestimate the electricity fuel share somewhat.

Figure 12: Residential space heating technology market share

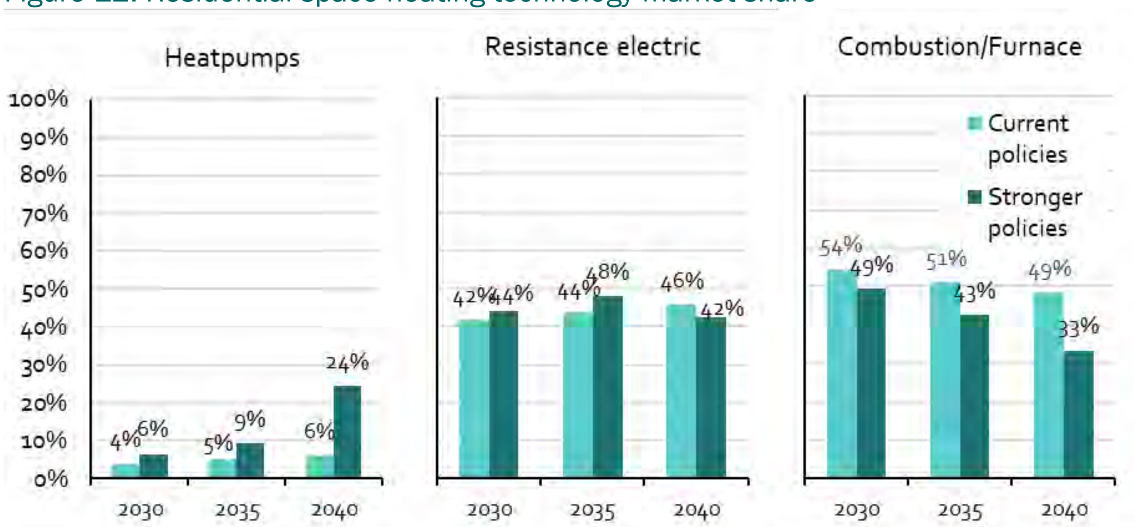
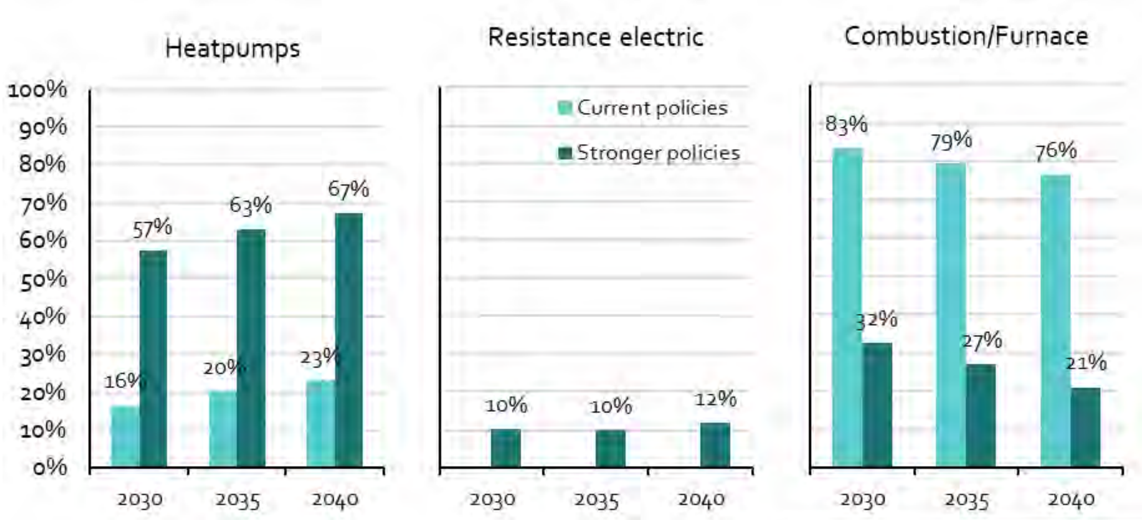
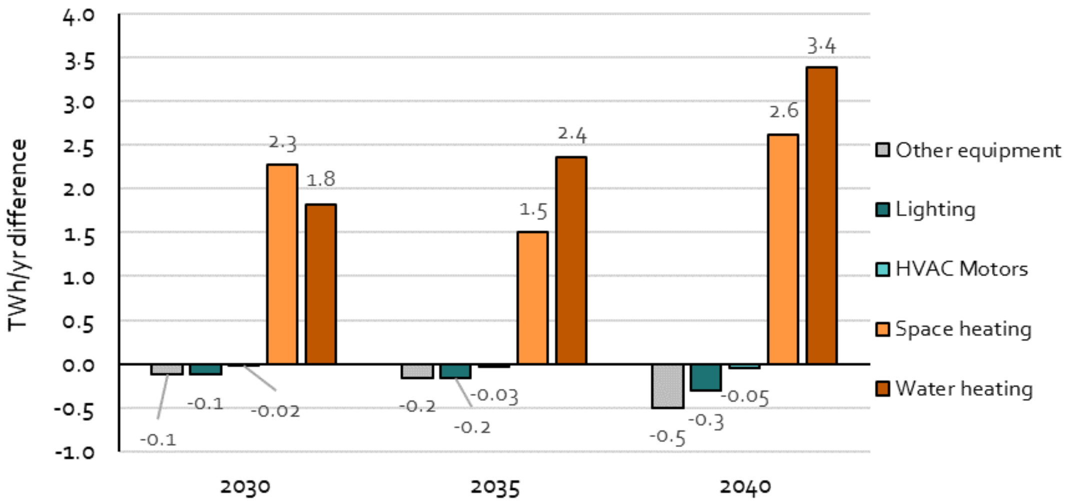


Figure 13: Commercial and institutional space heating technology market share



The electrification of space and water heating is offset by other energy efficiency slower growth in total building floor area. The stronger GHG policies result in more electricity consumption in buildings for space and water heating, relative to what would happen with current policies. However, some of this new load is offset by slower growth in electricity demand for lighting, plug-loads, motors used to for HVAC systems, and other equipment. In 2030 these changes offset about 7% of the incremental load growth. By 2040, they offset 14% of the incremental load growth (Figure 14). About half of this offset is a result of greater energy efficiency. The growth in provincial electricity consumption puts upward pressure on electricity prices, increasing the incentive to use more energy efficient equipment. The other half of the offset results from slower growth in floor area, a result of GHG reduction policies slowing economic growth (e.g. the services sectors grow more slowly and need less physical space).

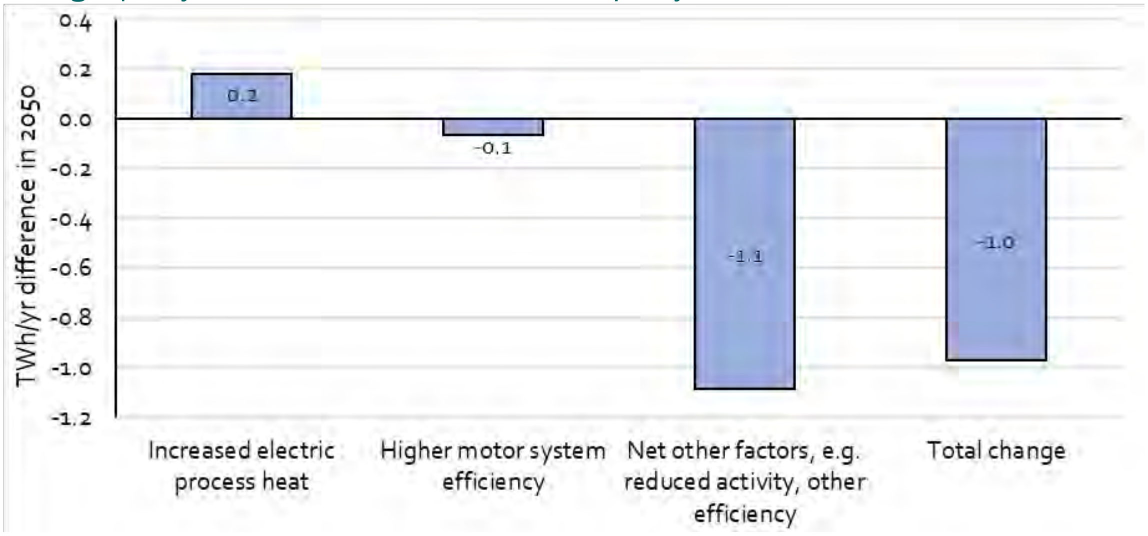
Figure 14: Difference in building electricity consumption by end-use in the stronger policy scenario relative to the current policy scenario



3.2.5. Mining and other industry

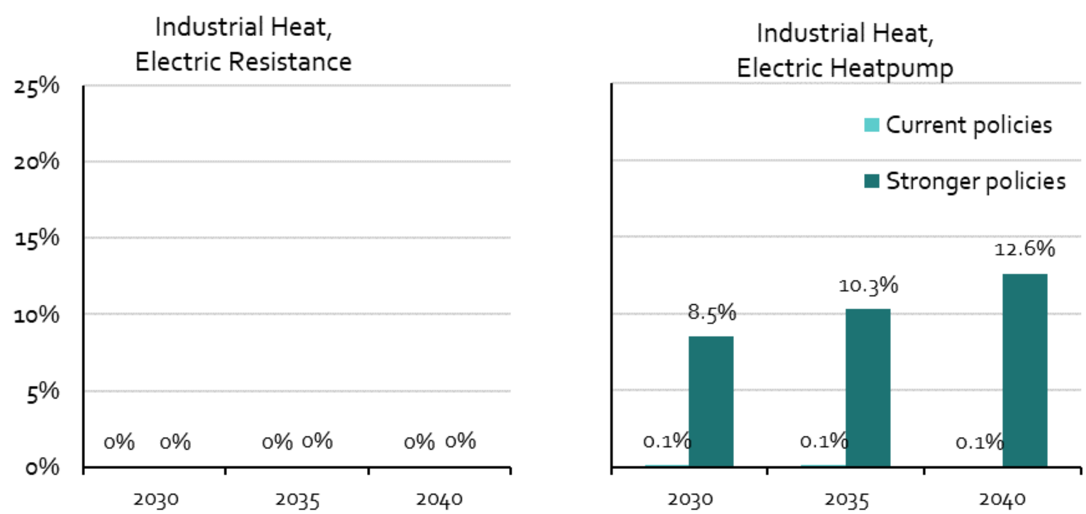
Electricity consumption from mining and other industry (i.e. not natural gas or LNG) is affected by several offsetting factors that ultimately result in less electricity consumption in response to stronger GHG policies. Electricity demand from mining and other industry is roughly 1 TWh/yr lower in 2040 than it would have been with a continuation of current policies (total demand is roughly 15 TWh/yr in 2030 and 16 TWh/yr in 2040). The offsetting drivers of industrial electricity demand are a switch to electricity for process heat, changes in sector activity, and other electrical efficiency. There is an increase in electric process heat, supplied by industrial heat pumps, equivalent to just 0.2 TWh/yr in 2040 (relative to current policies). However, this electricity consumption is more than offset by the adoption of more efficient motor systems (in response to higher electricity prices, -0.1 TWh/yr) and slower economic growth activity (-1.1 TWh/yr) (Figure 15). Note that any change in demand related to electric transportation within the industrial sectors is included with medium and heavy-duty vehicles.

Figure 15: Change in mining and other industrial electricity demand (2040) in the stronger policy scenario relative to the current policy scenario



The use of electricity for industrial heat increases in response to the stronger GHG reduction policies. Lower temperature process heat is supplied by industrial heat pumps drawing on ambient heat or providing active heat recovery from waste heat streams. By 2040, with the stronger GHG policies, heat pumps supply almost 13% of industrial process heat, which represents roughly 50% of the technical potential for this technology in the model (where we have limited heat pumps to supplying heat at 100 ºC or lower) (Figure 16). There is little use of electric resistance for industrial process heat by 2040, in even in response to the stronger GHG policies.

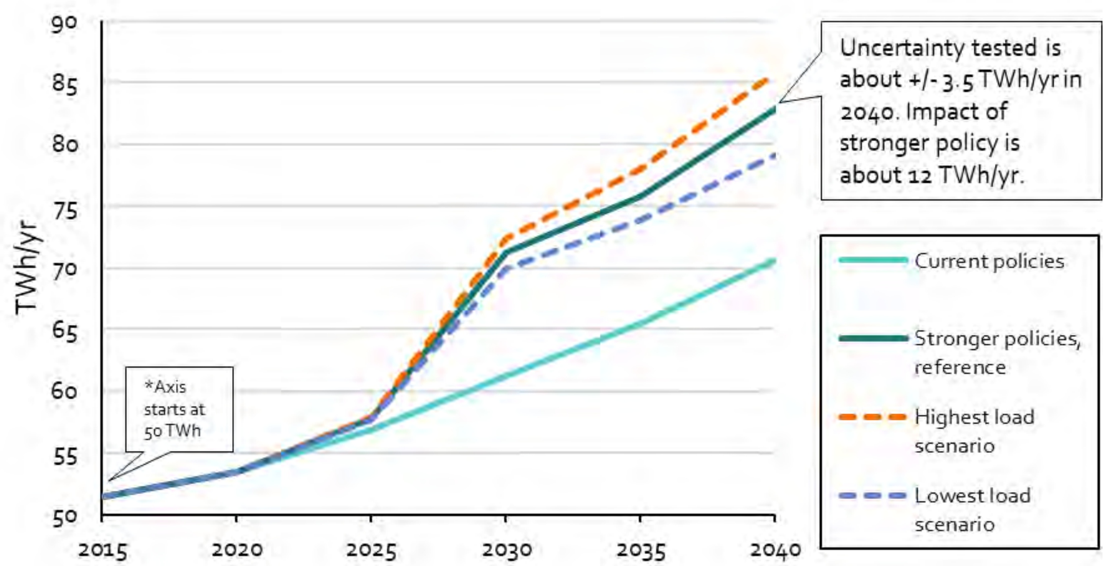
Figure 16: Electric industrial process heat technology market shares by scenario, % of total heat demand



3.3. Sensitivity analysis

Total electricity demand in BC is much more sensitive to the strength of GHG policy than it is to the technology uncertainties tested in the sensitivity analysis. Uncertainty in the future cost and performance of GHG reduction technologies create a band around the stronger policy electricity demand forecast of +/- 1.5 TWh/yr in 2030, growing to +/- 3.5 TWh/yr in 2040 (+/- 4%). In that year, provincial electricity demand could range from 79 to 86 TWh/yr (Figure 17). In contrast, strong GHG policy has an impact on electricity demand that is almost four times larger. Achieving the provincial GHG targets increases demand by 15 TWh/yr in 2040 compared to a future with a continuation of current policies.

Figure 17: British Columbia electricity demand in the stronger policy scenario with high/low range (note that the vertical axis starts at 50 TWh)



If BC achieves it's GHG targets, the largest uncertainty with respect to electricity demand is the future cost of PEVs. Lower and higher future for PEVs across of all vehicle classes can change electricity demand in 2040 by almost 7 TWh/yr (Figure 18, up to 8% of total demand with stronger policies). Two thirds of this variation comes from light-duty vehicles. While the ZEV standard puts applies a floor to light-duty ZEV sales, this policy is not binding from 2030 onwards when using the reference and lower PEV cost assumptions. PEV sales are instead driven by the implied carbon price required to achieve provincial GHG targets, meaning there are more sales than required by the ZEV standard. Just complying with the ZEV standard, as would occur if PEVs have higher costs, means half of all light-duty vehicles are be PEVs in 2040

(Figure 19). However, if PEV are less costly than expected, three quarters of vehicles on the road could be PEV by 2040 (Figure 19). The remaining variation in electricity demand comes from uncertainty in the stock larger vehicles, where the fraction of travel activity (i.e. tonnes km/yr) on PEVs in 2040 ranges from 18-33% for medium-duty vehicles and 10-16% for heavy-duty vehicles (Figure 19).

Interestingly, the high/low electrification scenarios that have multiple differences in assumptions relative to the reference stronger policy scenario produce a smaller net-change in electricity consumption than do the PEV cost scenario (Figure 18). This result indicates that uncertainties in future technology costs and performance may have offsetting impacts on electricity demand.

Figure 18: Difference from total electricity demand in the reference stronger policy scenario in 2040, all sensitivity scenarios

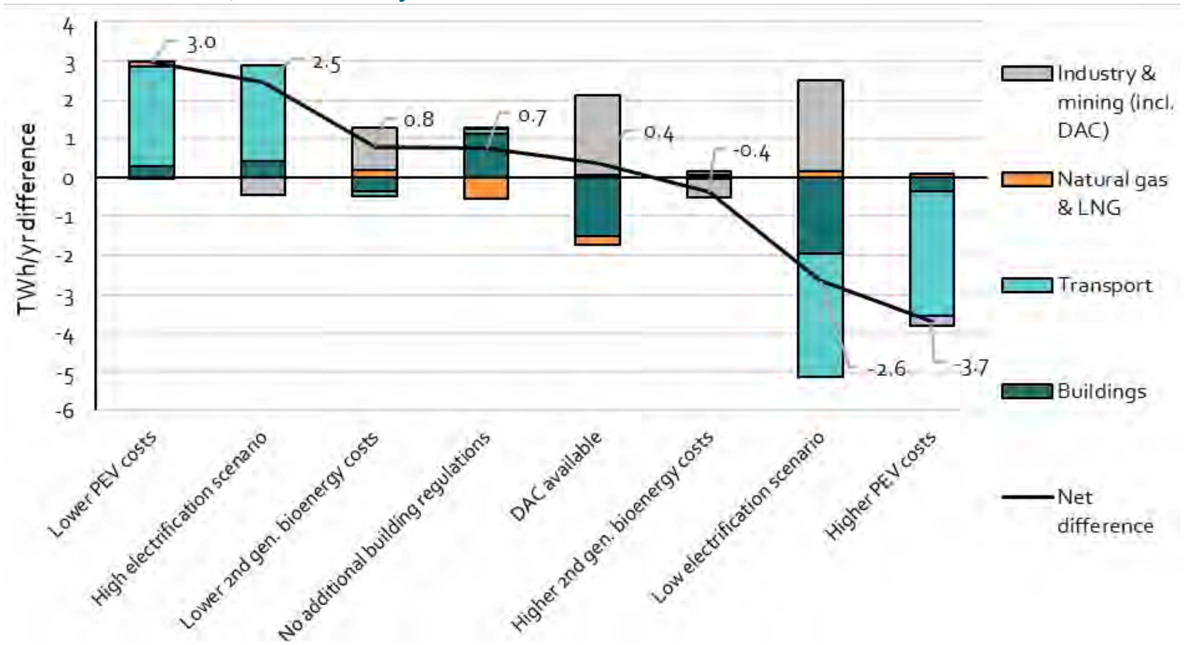
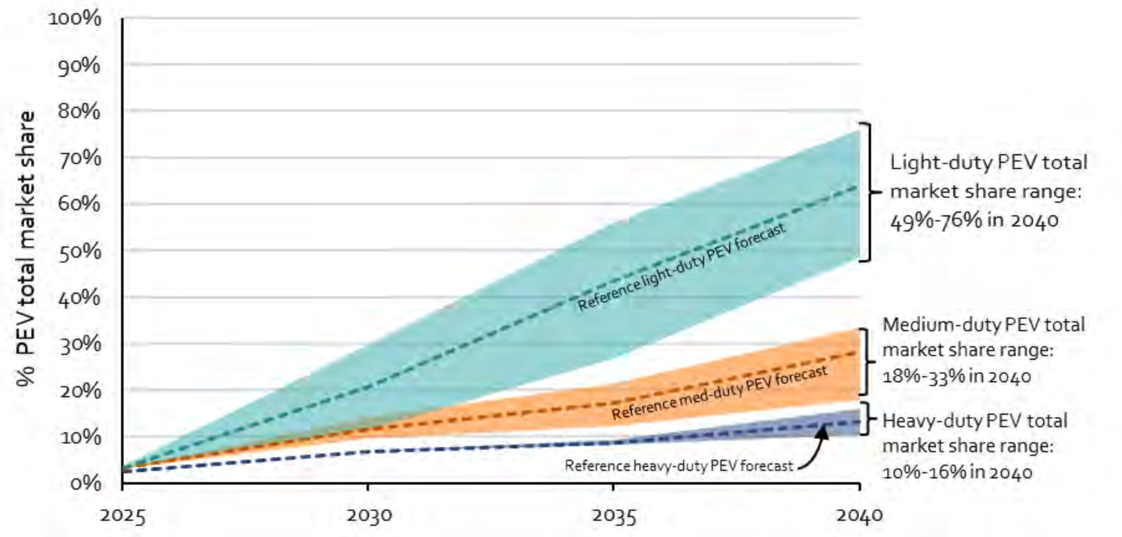


Figure 19: Uncertainty in PEV total market share (approximates % vehicles on the road for light-duty, approximates % of travel activity for medium and heavy-duty)



The cost and availability of direct air capture (DAC) and storage of CO_2 is a smaller uncertainty in these results. DAC and CO_2 storage affects electricity demand in three ways that partially offset each other. First, DAC and storage is a direct consumer of electricity. Although the DAC process characterized in this analysis uses natural gas for process heat (With carbon captured from the flue gas), it also uses a substantial amount of electricity, about 0.24 MWh/tCO_2. Second, DAC changes the extent to which other sectors must decarbonize, which changes the amount of electrification that occurs in those sectors. Third, more broadly, DAC changes the strength of policy (and policy cost) required to achieve BC's GHG target which can result in greater industrial activity and more electricity consumption. For example, if DAC is available, there is less electrification of buildings and the natural gas sector (-1.7 TWh/yr relative to the reference stronger policy scenario). DAC and storage uses an additional 1.2 TWh/yr, while the additional industrial activity indirectly caused by DAC consumes another 0.9 TWh/yr. On net, the use of DAC in response to stronger GHG policies in 2040 increases electricity demand by only 0.4 TWh/yr (0.5%) relative to a future without DAC (Figure 18).

The uncertainty of DAC in BC's future electricity consumption could be larger than it appears in this analysis, likely of similar magnitude to the uncertainty in PEV electricity consumption. First, DAC could increase electricity consumption if electricity is used to provide the process heat, though this approach would require abundant, low-cost and low-GHG electricity to make it cost competitive with gas-fuelled DAC. In a future with more extensive use of intermittent renewables, there could be daily or seasonal periods with excess generation when electricity is available at a low-price that would make all-electric DAC competitive. However, this analysis does not have the short-term resolution to explore this potential (i.e. hourly). Furthermore, all-electric DAC was not included in the model and even if it were, it would not be adopted with average-cost electricity prices. Second, DAC and storage could reduce electricity consumption in BC if the abatement occurs in another jurisdiction. Theoretically, BC could fund DAC and claim the emissions reductions credits, even if the physical process and electricity consumption occurs in another jurisdiction with lower-cost CO_2 storage. Both of these factors increase the uncertainty in BC's electricity consumption introduced by DAC, likely putting it in the range of +/- 2 TWh/yr in 2040.

Electricity demand through to 2040 is not sensitive to the production cost of 2nd generation biofuels or to more stringent building regulations. Lower and higher costs for renewable gasoline, diesel and natural gas produced from woody or grassy feedstocks have a small impact on industrial electricity consumption in 2040 (directly related to biofuel production) and an even smaller impact on electricity consumption for transportation (a minor substitution of biofuels for battery electric vehicles). Not implementing stronger building regulations after 2030 (the zero-emissions building regulation and building envelope retrofit requirement) increases electricity demand by 0.7 TWh/yr in 2040 (+0.8%) (Figure 18). Without these policies, buildings need on average more heating and there is more heating produced with electric resistance rather than heat pumps. Due to the slow turnover of building stock and mechanical systems, the impact of the additional building regulations should grow larger after 2040.

4. Discussion and Conclusions

In this analysis, we used a technologically detailed, full-economic equilibrium, energy economy model to simulate how different GHG policy portfolios will affect electricity consumption in BC from the present to 2040. We tested the impact of:

- "Current policies", that are legislated or have firm announcements
- "Stronger policies", which include a range of additional incentives and regulatory policies, plus an emissions cap that achieves BC's 2025, 2030 and 2040 and GHG emissions targets.

Using the stronger policy scenario as a reference, we also tested how the forecast of electricity demand is affected by a range of different technology and policy assumptions.

Of the dynamics tested, **BC's long-term electricity demand is most sensitive to the strength of climate policy**. In 2025, the difference between current policies and stronger policies is relatively small, just 1 TWh/yr more if BC achieves its GHG target. This difference grows to 10 TWh/yr in 2030 (+17%) and 12 TWh/yr in 2040 (+18%, with total electricity demand at 83 TWh/yr).

In response to stronger GHG reduction policies that will achieve the provincial GHG targets, **most of the incremental growth in electricity demand comes from the natural gas sector and from buildings**. 45% of the incremental demand comes the electrification of compressors used for natural gas production and transportation. Another 38% of the incremental demand comes the electrification of space and water heating in buildings. Just 18% of incremental demand comes from transportation. Electricity demand for transportation must grow significantly in order to achieve deep GHG reductions in BC. However, much of this load growth is already included in the current policy forecast since it includes the light-duty vehicle ZEV standard.

In contrast to the impact of GHG policies, **the other uncertainties tested in this analysis only shift total electricity demand in 2040 by a few TWh/yr relative to our reference forecast with stronger policies**:

- **The future cost of PEVS is the largest uncertainty, but a wide range of assumptions only shifts electricity demand by around +/- 3.5 TWh/yr in 2040.** Two thirds of this range comes from greater or lesser adoption of light-duty PEVs after 2030, when low-cost PEVs might drive sales beyond what the ZEV standard requires. The remaining third of this range comes from medium and heavy-duty PEVs. Even when assuming lower costs, PEVs are still a minority of these vehicle classes. By 2040, PEVs are used for, at most, 33% of medium-duty and 16% of heavy-duty travel. Given the additional potential to electrify these larger vehicles, the adoption of medium and heavy-duty PEVs could be significantly more important after 2040 and we recommend ongoing study of their electrification.

- **The cost and availability of direct air capture (DAC) and storage of CO_2 is a smaller uncertainty in these results.** DAC is a direct consumer of electricity, but it also changes the need for electrification in other sectors and reduces the strength of policy required to achieve BC's targets, which may indirectly result in greater economic activity and electricity demand. Because these dynamics largely offset each other, DAC appears to have a limited impact on future electricity demand. However, this uncertainty could be larger: DAC could be deployed in an all-electric configuration (i.e. higher electricity demand in BC), or BC could fund DAC that occurs in another jurisdiction (i.e. lower electricity demand in BC).
- **Electricity demand through to 2040 is not sensitive to the production cost of 2nd generation biofuels or to more stringent building regulations.** A longer-term analysis, to 2050 for example, might find that these uncertainties become more important.

In summary, **this analysis shows that achieving BC's GHG reduction targets will result in substantially more electricity demand than would occur with current policies.** The results do not show a future where other potential low-GHG energy pathways out-compete electricity. Rather, these pathways, including bioenergy, energy efficiency and some use of hydrogen fuel cell vehicles, are complementary and all contribute to deep GHG reductions.

However, this conclusion is subject to two limitations of this analysis. First, **This sensitivity analysis did not look at the impact of uncertainty in future natural gas production, yet this would introduce more uncertainty into the electricity demand forecast.** Electricity consumption in the natural gas sector is roughly 8 TWh in the stronger policy scenario in 2040 (almost 10% of total demand). Lower or higher natural gas prices, related to uncertainty in the North American natural gas supply curve (i.e. quantity available at a given production cost), could change BC's gas production and the related electricity demand substantially. Similarly, uncertainty in foreign demand for LNG, which is linked to gas production in BC within this analysis, would have the same impact. Based on the quantity of electricity used by the natural gas sector, this uncertainty could be at least as important to future electricity demand as is the uncertainty in PEV costs.

Finally, there are additional transportation modes that could electrify, but they are not included in this analysis. Consequently, electricity consumption for transportation could be higher than forecasted. Specifically, there will likely be niches for the electrification of marine and air transport. For example, Norled, a Norwegian ferry operator is already using a battery-electric ferry on one of its routes and has placed an order for more of these vessels.[16] For aviation, Harbour Air, based in BC, has announced that it plans electrify its short-haul seaplanes,[17] and Airbus is testing the electrification of one of its regional turbo-fan powered aircrafts.[18] The model results provide an upper bound on this uncertainty. If all domestic marine and air travel included in the analysis were to electrify, this would increase total electricity demand by 7 to 10 TWh/yr in 2040, depending on the growth of these sectors.[19] For context, total electricity demand from on-road PEVs grew to roughly 10 TWh/yr in 2040 in the stronger policy scenario. However, by analogy with the electrification of medium and heavy-duty vehicles observed in this study, actual electricity demand from marine and air travel would be a subset of the maximum. Given that electric boats and planes would likely be used for short and high-frequency routes, an approximate guess for that new load would be in the range of 2 to 3 TWh/yr by 2040.

---

[16] Corvus Energy. (2017). *World's First All-Electric Car Ferry*. Available from: www.corvusenergy.com

[17] Harbour Air Seaplanes (2019). *Harbour Air and magniX Partner to Build World's First All-Electric Airline.* Available from: link.

[18] Airbus (2019). *A Giant Leap Toward Zero-Emission Flight*. Available from: link.

[19] Assuming that electric propulsion has an end-use efficiency that is three times greater than combustion-based propulsion.

Appendix A: Electrification Technology Research

This appendix describes research conducted for the electrification potential review and how this information was used in the analysis. It covers six topics:

- The cost and potential for 2nd generation biofuels a as low-carbon fuel that competes with, or complements, GHG abatement through electrification.
- Updated cost assumptions for light-duty electric vehicles and assumptions for the energy intensity of these vehicles.
- The cost and potential for battery electric vehicles for bus transit.
- The cost and potential for battery electric vehicles for heavy-duty truck transport.
- The opportunity for low-energy electric heating in industry with industrial heat pumps.
- The cost and energy intensity of direct air carbon capture.

2nd Generation biofuels

In this report, 2nd generation biofuels refer to liquid and gaseous fuels produced from ligno-cellulosic feedstocks. These are cellulosic ethanol and renewable gasoline, diesel and natural gas produced from wood or grassy organic matter. These contrast with first generation biofuels which include starch ethanol and biodiesel. Starch ethanol is produced from sugary and starchy crops such as wheat and corn. Biodiesel is produced from oilseeds (e.g. canola and soy) and can also be produced from a limited quantity of used cooking oil and tallow (fat by-products from animal production). We also include hydrogenation derived-renewable diesel as a first-generation biofuel given that it can be produced from the same feedstocks as biodiesel.

Currently, 2nd generation biofuels are pre-commercial and their production is more technically advanced and costly than the production of first-generation biofuels. However, 2nd generation biofuel feedstocks are more plentiful than those for first generation biofuels and the commercialization of 2nd generation biofuel is generally viewed as a necessary for the widespread substitution of fossil fuels with bioenergy.

The following section describes the feedstocks available for 2nd generation biofuels in the model in terms of their source, quantity, and cost. Feedstock quantities are always described in terms of dry mass (e.g. Oven dry tonnes or ODt). It then describes the fuel production pathways included in the model in terms of their capital and operating costs, their feedstock conversion efficiency and the lifecycle GHG intensity of the finished fuels. Based on these attributes, we can compare the quantity and cost of 2nd generation biofuels available within the model with the incumbent fuels: gasoline, diesel and natural gas.

Table 13 summarizes the feedstocks for 2nd generation biofuels represented in gTech. Table 14 summarizes the fuel production technologies. Production costs and GHG abatement costs are shown with the reference model inputs for biofuel plant capital costs (not necessarily the same as literature estimates). The fuel carbon intensities are calculated based on the 2010 GHG intensities for inputs like truck transportation and hydrogen production. If the GHG intensity of these inputs declines, so too will the biofuel carbon intensities and the abatement cost. The production potential (PJ/yr and fraction of gasoline/diesel or natural gas replaced) is only a snapshot for 2010 designed to give context to the quantity of fuel available.

Table 13: Summary of 2nd generation biofuel feedstock modelling assumptions

	Agriculture residue	Forestry residue	Total
Residue availability in 2010, million ODt/yr	18.2	15.7	33.9
Residue availability in 2010, PJ/yr	337	238	575
Plant-gate feedstock cost, 2010 CAD/ODt	76	88	74.5 (avg.)
Potential for greater future production	Modest: grows with food production	Modest: Forestry activity in 2010 was low, allowable cuts across Canada are higher, though future wood supply is constrained in BC as a result of the mountain pine beetle	-

Table 14: Summary of 2nd generation biofuel production modelling assumptions (reference inputs, not sensitivity scenario inputs). Costs in 2010 CAD.

	Renewable gasoline and diesel	Cellulosic ethanol	Renewable natural gas
Production costs, 2010 CAD assuming residue cost of $74.5/ODt	$1.04/L	$0.66/L	$18/GJ
Fuel lifecycle carbon intensity in 2010,[a] gCO_2e/MJ	20 (-77% from gasoline)	11 (-88% from gasoline)	6 (-90% from nat. gas)
Maximum production potential in 2010 if all feedstock available in 2010 were used for a given fuel, PJ/yr	384	263	453
Fraction of incumbent fuels replaced if all feedstock available in 2010 were used for a given fuel (% of 2010 Canadian consumption	15 % of gasoline and diesel	10% of gasoline and diesel	13% of natural gas
Abatement cost with model inputs (2015 CAD/tCO_2e)	142	104	247

[a] Accounts for energy used for feedstock extraction, transport and transformation to fuel, as well as additional fertilizer requirement for agricultural residue, based on 2010 GHG intensity of these activities in gTech

[b] Abatement cost for renewable gasoline and diesel and cellulosic ethanol measured relative to a gasoline lifecycle GHG intensity of 85.7 gCO_2e/MJ, and as assumed wholesale price of $0.70/L (roughly $70/bbl USD for oil). Abatement cost for renewable natural gas measured relative to a natural gas lifecycle GHG intensity of 58 gCO_2e/MJ, and as assumed wholesale price of $5/GJ (2010 CAD).

Feedstocks

The 2nd generation biofuel feedstocks included in the model are agricultural and forestry harvest residues. Agricultural residues are the remainders of plants after harvest such as corn stover and wheat straw. Forestry harvest residues are the branches and treetops that are piled and left at the side of forest roads during logging. Residue availability is defined for each source in 2010 as a function of agricultural and forestry activity and the quantity can grow or shrink as the activity of the associated sector changes (i.e. more forestry activity produces more harvest residue).

Agricultural Residue

In 2010, the model includes 18.2 Mt/yr of agricultural residue that is sustainably available as a feedstock (Table 15). At roughly 18 PJ/million ODt, this residue contains 328 PJ. This quantity was estimated by deriving the quantity of residue available from each of the primary grain crops in Canada using the Biomass Inventory Mapping and

Analysis Tool (BIMAT) and its corresponding data.[20] Other crops produce significantly less residue and are not included. Only a portion of all available agricultural residues can be sustainably harvested as biofuel feedstock since more than 50% of it is kept on the ground for tilling to prevent erosion and to maintain soil nutrients. Roughly 20% of residue is used for as animal bedding for livestock production leaving less than 30% of residue available for fuel production. The sustainable amount of residue available per tonne of grain was multiplied by total grain production in 2010[21] to yield total residue production in that year.

Agricultural residue supply is tied to agricultural production in gTech in Canada and the USA. Therefore, the supply can increase if total agricultural production increases or if there is a shift in the composition of crops (e.g. more corn and less wheat would yield more residue). However, agricultural production is constrained in gTech assuming a fixed land-base, so the model will not allow runaway residue production, nor does it allow runaway production of first-generation biofuel feedstocks.

Table 15: Summary of agricultural residue availability in Canada in 2010, as represented in gTech (reference scenario inputs)

Parameter	Units	Barley	Corn	Oat	Wheat	Total[a]
Residue yield[b]	$ODt_{residue}/t_{grain}$	0.90	0.67	1.52	1.22	1.13
Portion available for energy[b]	%	21.3%	72.9%	28.7%	18.9%	28.5%
Residue available for energy	$ODt_{residue}/t_{grain}$	0.19	0.49	0.44	0.23	0.32
Grain production in 2010[c]	Mt	7.6	21.0	2.5	23.3	54.4
Residue available for energy in 2010	Million ODt	1.5	10.3	1.1	5.4	18.2

a Flax data is not shown since no flax residue is available for energy

b Source is BIMAT

c Source is Statistics Canada

Forestry Harvest Residue

In 2010, the model includes 15.7 million ODt/yr of forestry harvest residue that is sustainably available as a feedstock.[22] At roughly 18 PJ/ million ODt, this residue contains 238 PJ. This quantity of biomass comes from roadside piles of branches and

[20] Agriculture and Agri-Food Canada. (2017). *Biomass Agriculture Inventory Median Values*. Available from: www.open.canada.ca

[21] Statistics Canada, CANSIM 001-0017

[22] Yemshanov D., McKenney, D.W., Fraleigh, S., McConkey, B., Huffman, T., Smith, S., 2014, *Cost estimates of post harvest forest biomass supply for Canada,* Biomass and Bioenergy, 69, 80-94

tree tops that are produced during whole-tree harvesting with clear-cut logging. It is net of residue that is not available due to technical reasons (e.g. too dispersed to be extracted) or sustainability reasons (i.e. must be left to maintain nutrients, habitat and forest carbon).

Forestry activity in 2010 was relatively low compared to the annual allowable cut, also known as the wood supply, which is an estimate of what can be sustainably harvested from Canadian forests each year. In 2010, the forestry sector harvested 138.6 million m^3 of wood, but the wood supply was 69% larger, at 234.9 million m^3.[23] The wood supply has been relatively stable in the past, ranging from 223 to 250 million m^3/yr between 1990 and 2015. However, the supply is constrained by natural factor such as the impact of the mountain pine beetle in BC. Notionally, if there is sufficient demand for Canadian wood products, then the quantity of forest harvest residue could about 50% larger (roughly 23 million ODt/yr).

Excluded Feedstocks

The analysis does not include forest product mills waste, urban wood waste and energy crops.

Forest product mill waste is a by-product of turning trees into forest products (e.g. lumber, panels). The quantity of mill residue is a function of demand for forest products and it similar in size to the harvest residue, estimated at 21 Mt/yr in 2005. However, it is generally already used for energy within the mills with some exported as wood pellets.[24] These other uses would compete against 2nd generation biofuels for wood feedstock, but the model does not currently account for this dynamic.

Urban wood waste primarily comes from deconstruction and urban silviculture. The supply is a function of the quantity produced per capita and the degree to which this waste is separated from the general waste stream for utilization. We estimate the quantity of urban wood waste available in Canada at 3 million ODt/yr based on a per capita production of 0.1 ODt/yr/person.[25] This quantity of wood is not insignificant, but because it is relatively small compared to agricultural and forest harvest residue, it is also not included in the analysis.

---

[23] Government of Canada, National Forestry Database, access May 28, 2018

[24] Bradley, D., 2009, Canada Report on Bioenergy 2009, Climate Change Solutions, NTL - IEA Bioenergy Task 40 - Biotrade

[25] Estimates for urban wood waste vary from 0.07 ODt/capita/yr (Tetra Tech (2015). *2015 Demolition, Land-clearing, and Construction Waste Composition Monitoring Program*, presented to Metro Vancouver), to 0.3 ODt/capita/yr (Agriculture and Agri-Food Canada (2018). *Biomass Inventory Mapping and Analysis Tool*)

Energy crops are excluded from the analysis due to the significant uncertainty in their potential and their GHG impacts. Energy crops will compete with other land-uses including agriculture, forests, prairies and pastures, so it is difficult to quantify how much land may be used for energy crop production. Furthermore, energy crop production can have a very large impact on soil carbon, both positive and negative, depending what crops are grown and where they are grown.[26] In other words, their production can emit or sequester significant quantities of carbon.

Feedstock costs and carbon intensity

The "at-the-plant cost" of agricultural residue in the model is $76/ODt (Table 16) (in 2015 CAD, as are all costs in the appendix). This cost is the sum of the residue's 'farmgate' and transportation costs. The farmgate cost is 69 $/ODt. based on a study crop residue extraction in Ontario.[27] Farmgate costs include harvest and nutrient replacement costs. Harvest costs come from chopping (for corn only), baling, collecting, and storing the residue. The nutrients in the residue that is removed from the fields must be replaced with fertilizers.

The transportation costs for agricultural residue are 7 $/ODt, informed by a study of corn stover transportation costs that are a function of distance travelled.[28] We used the BIMAT online tool to determine an average transportation distance of 40km. The distance is half the radius of an area that can produce roughly 0.72 million ODt/yr of residue (the input for an archetypal biofuel plant in gTech), measured at several locations across Canada using BIMAT.

The "at-the-plant cost" of forest harvest residue in the model is $88/ODt (Table 16). This is based on an assumed harvest cost of $57/ODt.[29] Yemshanov et al. (2014) estimated the transportation cost of forest residue to the nearest existing biomass cogeneration plants with costs ranging from $5/ODt to over 120 $/ODt. We use an average transportation cost of $31/ODt under the assumption that biofuel plants

---

[26] US Department of Energy (2016) 2016 Billion-Ton Report

[27] Kludze, H., Deen, B., Weersink, A., van Acker, R., Janovicek, K., De Laport, A., McDonald, I. (2013). *Estimating sustainable crop residue removal rates and costs based on soil organic matter dynamics and rotational complexity*. Biomass and Bioenergy, 56, 607-618

[28] Petrolia, R., D. (2008). *The economics of harvesting and transporting corn stover for conversion to fuel ethanol: A case study for Minnesota.* Biomass and Bioenergy, 32, 603-612

[29] Yemshanov D., McKenney, D.W., Fraleigh, S., McConkey, B., Huffman, T., Smith, S., 2014, *Cost estimates of post harvest forest biomass supply for Canada,* Biomass and Bioenergy, 69, 80-94

could be located to mitigate transportation costs (e.g. co-located at existing forest products sites that do not have cogeneration and were not included in the analysis by Yemshanov et al. (2014)).

Table 16: 2nd generation biofuel feedstock production cost assumptions (2015 CAD/ODt)

	Agricultural residue	Forest harvest residue
Harvest/Extraction costs	$35	$57
Transportation to fuel plant	$7	$31
Nutrient replacement	$34	-
Total "at-the-plant" Cost	**$76**	**$88**

Note that the model is a general equilibrium model and all costs result from a corresponding demand for a good or service and will result in energy consumption and GHG emissions from that demand. For example, the transportation costs increase the activity in the truck transportation sector which increases energy consumption and GHG emissions in that sector. Likewise, nutrient replacement increases fertilizer production and the associated energy consumption and GHG emissions. Based on the gTech GHG intensity for truck transportation and fertilizer production in 2010, the carbon intensity of agricultural residue in 2010 is 0.09 $tCO_2e/t_{residue}$ (30% from extraction and transport, 70% from fertilizer). The carbon intensity of forest harvest residue in 2010 is 0.07 $tCO_2e/t_{residue}$ (100% from extraction and transport). The cost and GHG intensity of transportation and fertilizer production can change over time, meaning the feedstock production cost and lifecycle GHG intensity can change as well. These feedstock carbon intensities are further described in the context of biofuel lifecycle carbon intensity in the next section.

Fuel production cost and carbon intensity

The ligno-cellulosic feedstocks within the model (agriculture and forestry residue) can be used to produce three 2nd generation biofuels in gTech: Renewable gasoline and diesel, cellulosic ethanol, and renewable natural gas. The archetypal representations of these fuel production processes are based on plants that consume 0.72 Mt/yr of ligno-cellulosic feedstock.

Renewable gasoline and diesel are modelled as a single fuel pathway that is a perfect substitute for gasoline or diesel. The fuels are produced together via fast-pyrolysis of feedstock into a bio-crude and followed by treatment with hydrogen to upgrade the bio-crude to finished fuels. Model assumptions are in Table 17, which shows the literature estimate for an archetypal plant capital cost: $743 million (2015 CAD) for a plant producing 229 million L/yr. However, because this technology is pre-commercial and there is significant uncertainty in its capital cost, the technology has a 50% cost premium in this analysis, raising the capital cost to $1,114 million (2015 CAD). Renewable gasoline and diesel production is mostly energy self-sufficient, though it does require some electricity as well as hydrogen which can be produced from natural gas.

Table 17: Renewable gasoline and diesel production archetype assumptions

Attribute	Value	Source
Archetype production, million L/yr	229	Jones et al. 2013[30]
Capital cost (literature estimate for for commercial plant), million 2010 CAD	$743	Jones et al. 2013
Capital cost (reference biofuel cost scenario), million 2010 CAD	$1,114	50% capital premium on above value
Operating cost, 2010 CAD $/L	$0.25	Jones et al. 2013
Electricity input, GJ/GJ fuel	0.08	GHGenius 4.03a/(S&T)² Consultants,[31] average for wood and agriculture residue
Hydrogen input, GJ/GJ $_{fuel}$	0.19	GHGenius 4.03a/(S&T)² Consultants, average for wood and agriculture residue
Feedstock input, $kg_{feedstock}/L_{fuel}$	3.15	GHGenius 4.03a/(S&T)² Consultants, average for wood and agriculture residue
Feedstock conversion efficiency, $GJ_{feedstock}/GJ_{fuel}$	63%	Derived from above assuming 18 $MJ/kg_{feedstock}$ and 35.5 MJ/L_{fuel}

The cellulosic ethanol fuel pathway in gTech is based on a biochemical process, using enzymes to produce ethanol from ligno-cellulosic feedstocks. The ethanol is functionally equivalent to ethanol produced from crops such as wheat or corn and it is not a perfect substitute for gasoline: We assume it can be blended at 15% by volume after 2020 once newer vehicles account for almost all vehicle stock. The capital cost assumption for cellulosic ethanol is $628 million (2015 CAD) for a 237 million L/yr plant, based on the observed cost of the first cellulosic ethanol plants (Table 18). The process is energy self-sufficient and produces a surplus of lignin which is assumed to be used for cogeneration of heat and power with some electricity export.

30 Jones, S., Meyer, P., Snowden-Swan, L., Padmaperuma, A., Tan, E., Dutta, A., Jacobson, J., Cafferty, K., 2013, Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels Fast Pyrolysis and Hydrotreating Bio-oil Pathway, National Renewable Energy Laboratory

31 (S&T)2 Consultants, 2012, Update of Advanced Biofuel Pathways in GHGenius

Table 18: Cellulosic ethanol production archetype assumptions

Attribute	Value	Source
Archetype production, million L/yr	237	Set equal to have annual feedstock demand as renewable gasoline/diesel
Capital cost (reference biofuel cost), million 2010 CAD	$628	IRENA 2013,[32] median of first plants
Operating cost, 2015 CAD $/L	0.19	Jones et al. 2013
Electricity output, GJ/GJ fuel	-0.05	GHGenius 4.03a/(S&T)² Consultants
Feedstock input, Kg feedstock per L fuel	3.04	GHGenius 4.03a/(S&T)² Consultants
Feedstock conversion efficiency ($GJ_{feedstock}/GJ_{fuel}$)	43%	Derived from above assuming 18 $MJ/kg_{feedstock}$ and 35.5 MJ/L_{fuel}, not including electricity production

The 2nd generation renewable natural gas technology is based on the G4 Insights' pyrocatalytic hydrogenation process which produces natural gas from ligno-cellulosic material via fast pyrolysis and hydrogen treatment. The process is energy self-sufficient, meaning that the feedstock is used to produce the fuel, the required hydrogen and the energy for the process. The feedstock to gas conversion efficiency is 74% on an energy basis (Table 19). We assume the capital cost for a plant producing 9.6 PJ/yr is $1.064 million based on a proposal for using the technology and a review of literature sources indicating a much higher capital cost for biomethane production.[33]

[32] International Renewable Energy Agency (IRENA), 2013, Road Transport: The Cost of Renewable Solutions

[33] Müller-Langer, F. (2011) Analyse und Bewertung ausgewählter zukünftiger Biokraftstoffoptionen auf der Basis fester Biomasse. Thesis, 2011, Technische Universität Hamburg-Harburg, Hamburg.

Carbo, M., Smit, R., Drift, B.v.d, Jansen, D. (2011) Bio Energy with CCS (BECCS): Large potential for BioSNG at low CO2 avoidance cost. Energy Procedia, 4, 2011, pp 2950-2954.

Hallbar Consulting (2017). Resource Supply Potential for Renewable Natural Gas in B.C.

Table 19: Renewable natural gas production archetype assumptions

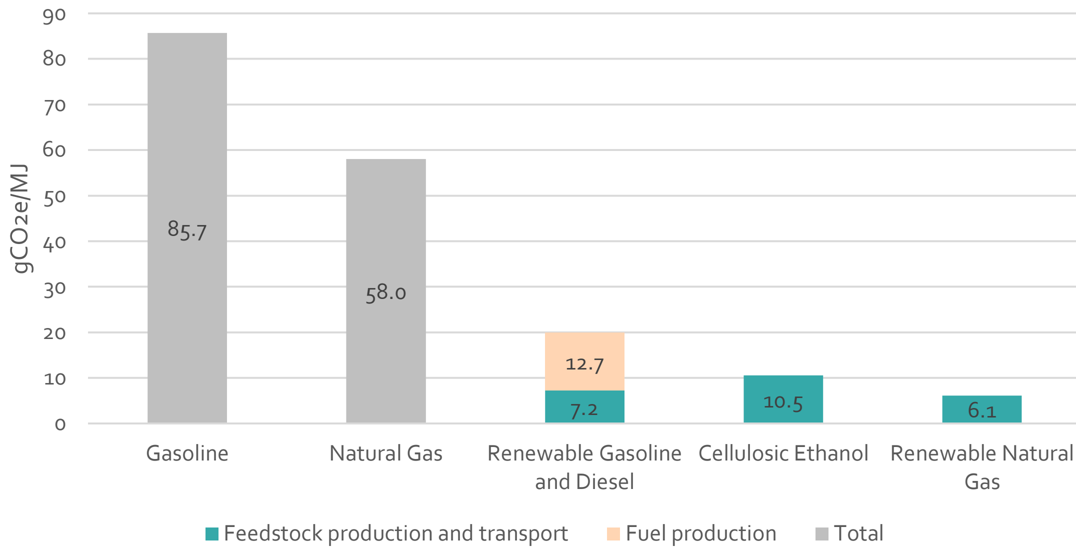
Attribute	Value	Source
Archetype production, PJ/yr	9.6	Set to have equal feedstock demand as other 2nd gen. fuel production archetypes
Capital cost (literature estimate for commercial plant), million 2015 CAD	$355	Chavez-Gherig et al., 2017[34]
Capital cost (reference biofuel cost), million 2015 CAD	$1,064	3x capital premium on estimated value
Operating cost, 2010 CAD $/GJ	1.30	Chavez-Gherig et al., 2017
Feedstock input, Kg feedstock per GJ fuel	75	G4 Insights[35]
Feedstock conversion efficiency ($GJ_{feedstock}/GJ_{fuel}$)	74%	G4 Insights

2nd generation biofuels provide a significant reduction in lifecycle carbon intensity (Figure 20). The carbon intensity of renewable gasoline/diesel and cellulosic ethanol are 77% and 88% lower than gasoline, respectively (excluding the GHG associated with intermediate inputs to biofuels, e.g. chemicals and enzymes). The carbon intensity of renewable natural gas is 90% lower than fossil natural gas. The carbon intensity of the biofuels mainly comes from diesel consumption (feedstock extraction and transport), fertilizer production (CO_2 by product GHG emissions during ammonia production) and hydrogen production (CO_2 by product GHG emissions during steam methane reformation, renewable gasoline and diesel only). If GHG reduction policy reduces the GHG emissions from these sources, the lifecycle carbon intensity of biofuels can decline further.

[34] Chavez-Gherig, A., Ducru, P., Sandford, M., 2017, The New Jersey Pinelands and the Green Hospital, NRG Energy Case Study

[35] G4 Insights, Our Technology, Accessed April 5th 2018

Figure 20: 2nd Generation Biofuel Carbon Intensity

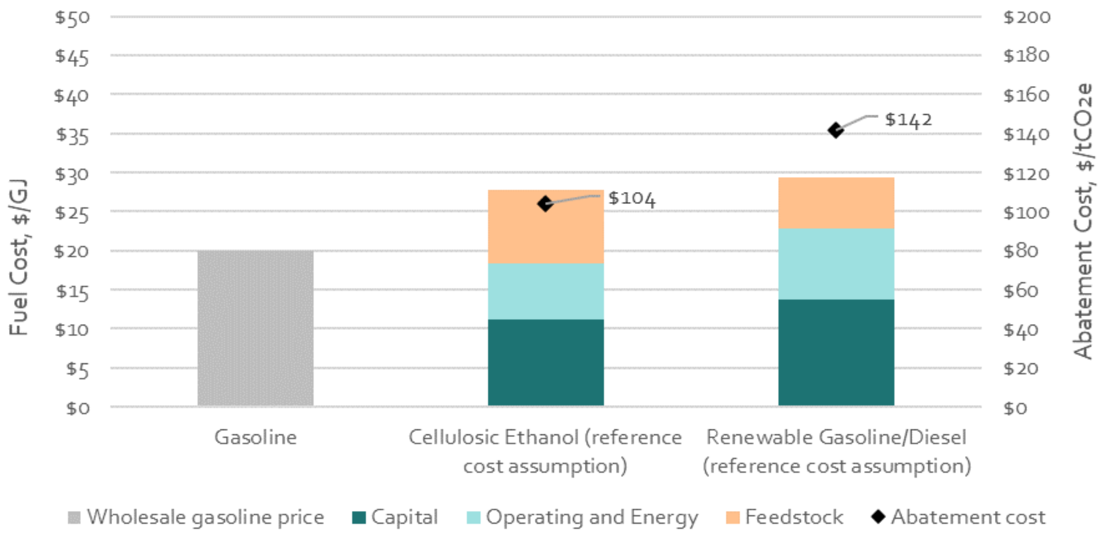


Gasoline and natural gas carbon intensity values from GHGenius 4.03a model, default Canadian values for 2016. Carbon Intensity of biofuels excludes GHG associated with intermediate inputs (e.g. chemicals). Electricity consumption GHG accounted assuming a 55% efficient natural gas-fired combined cycle power plant operating at 327 kg/MWh. Feedstock carbon intensity assumed 50% agricultural residue and 50% forest harvest residue.

With the reference biofuel cost scenario assumptions for 2nd generation biofuel production capital costs, the production cost for cellulosic ethanol is \$26/GJ (2010 CAD, equivalent to \$0.61/L). If the gasoline production cost is \$20/GJ (\$0.70/L, based on 70\$/bbl US oil), the GHG abatement cost is \$80/tCO_2e (Figure 21. With the reference biofuel cost scenario assumptions for renewable gasoline and diesel production capital costs, that fuel costs \$32/GJ (\$1.14/L), with an abatement cost relative to gasoline of \$185/tCO_2e (Figure 21).

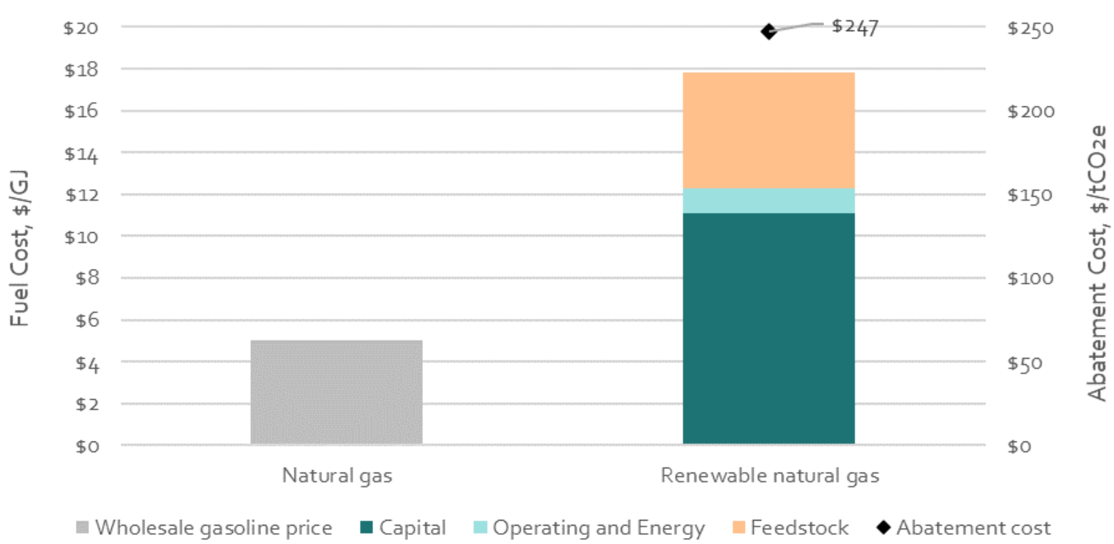
Similarly, the cost of renewable natural gas produced from ligno-cellulosic material is \$13.4/GJ with using the reference scenario assumptions for its capital cost (Figure 22). At this cost, the abatement cost is \$162/tCO_2e when the price of natural gas is \$5/GJ (2010 CAD).

Figure 21: 2nd Generation Liquid Biofuel Production and Abatement Cost (2010 CAD)



The cost of gasoline is calculated assuming a $70/bbl price, a Canada/US exchange rate of 1.25 and a refining margin of $0.15 2015 CAD/L. Ligno-cellulosic feedstocks are assumed to cost $74/ODt, an average of agricultural and forestry harvest residue supply costs in gTech. The abatement cost of cellulosic ethanol does not account for an improvement in the energy efficiency of the vehicle and or a reduction in the cost of gasoline blendstock it is blended with due to lower octane requirements.

Figure 22: 2nd Generation Gaseous Biofuel Production and Abatement Cost (2010 CAD)



The cost of natural gas is assumed at $5/GJ. Ligno-cellulosic feedstocks are assumed to cost $74/ODt, an average of agricultural and forestry harvest residue supply costs in gTech.

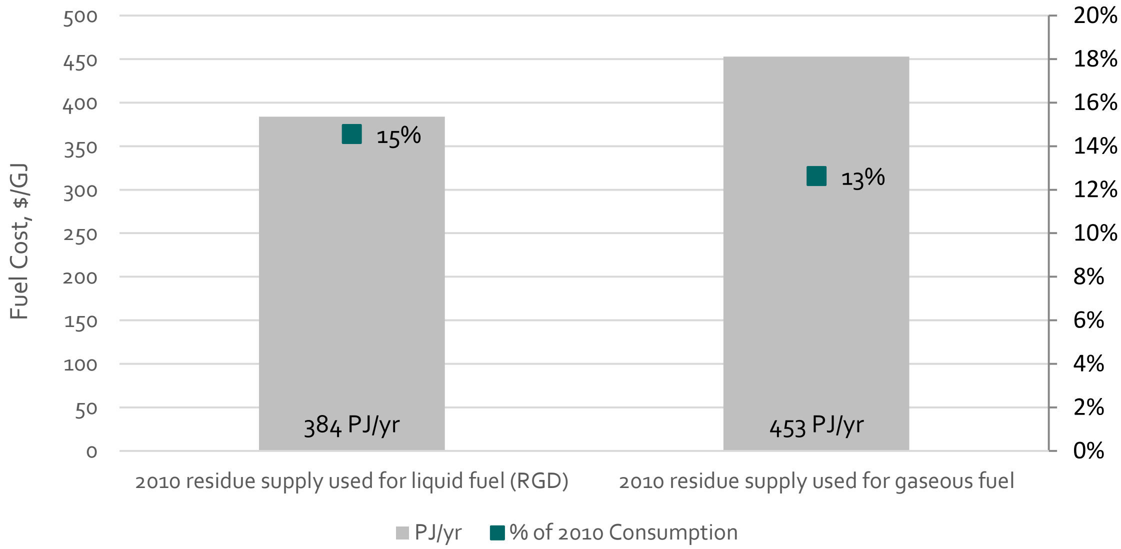
Production potential

If all residues available in 2010 calculated in the previous sections were used to produced renewable gasoline and diesel then the quantity of fuel produced would be 384 PJ/yr (15% of gasoline and diesel consumption in Canada in 2010) (Figure 23). If that residue were used to produce gaseous fuel, the quantity of natural gas produced would be 453 PJ/yr (13% of fossil natural gas consumption in 2010, including own use and consumption of natural gas to generate electricity.

This estimation of the 2^nd^ generation biofuel production potential is only meant to illustrate the magnitude available: it is a potentially significant low-carbon energy resource, but it cannot replace current fossil fuel consumption. There are some important caveats to keep in mind when interpreting this data:

- Residue production can increase: Somewhat more agricultural production is possible, though land is constrained in gTech, and potentially 50% more forestry activity is possible with a proportional increase in forestry harvest residue.
- Fossil fuel consumption will decline in most scenarios where 2nd generation biofuels are used: GHG reduction policy will drive more energy efficiency and electrification. These will reduce the total quantity of fossil fuel required, be it fossil or bio-derived. Therefore, the fraction of fossil fuel than can be substituted with 2nd generation biofuels will be larger than shown in Figure 23.
- The USA has a substantial supply of residue that could be used for fuel. However, if there is strong GHG reduction policy in the US, there would be substantial new demand for bioenergy. Therefore, the impact of US on the supply of feedstock available for Canadian fuel consumption is important.
- Other residues are available and could increase the production potential. For example, urban wood waste could increase the potential shown in Figure 23 by another: e.g. urban wood waste is available and could increase the production potential by another 50-60 PJ/yr.

Figure 23: Fuel production potential if the quantity of residue characterized in gTech in 2010 is converted to liquid fuels (renewable gasoline and diesel) or gaseous fuel: PJ/yr fuel (bars, left axis) and fraction of incumbent fossil fuel (points, right axis)



Assumptions for light-duty vehicles

The model includes two internal combustion engine vehicle technologies, and one of each hybrid, plug-in hybrid, battery electric, and fuel cell vehicle technologies in the light-duty sector. Archetypes are based on a midsize passenger car with a 150-kW power output. An intangible cost is added to represent perceived cost due to range anxiety as well as the actual cost of renting an internal combustion engine (ICE) vehicle for trips longer than the electric vehicle's assumed range.

The cost breakdown for the basic gasoline vehicle archetype is based on a 2015 Idaho National Laboratory report. The Energy Information Administration's National Energy Modeling System documentation is used to define the incremental cost and efficiency improvement for the efficient gasoline vehicle archetypes. The cost breakdown for battery electric vehicles is informed both from the UBS Bolt Teardown report and Bloomberg's battery cost assumptions. The cost breakdown for hybrid and plug-in hybrid vehicle costs is calculated using a combination of ICE and electric vehicle costs as reported in Argonne National Laboratory's 2016 Autonomie Model. The plug-in hybrid archetype in the modelling is based on Argonne's depiction of an extended range plug-in hybrid as opposed to a split drive plug-in hybrid. Battery energy density is assumed to improve by 2% per year between 2015 and 2025, after which it remains constant. Fuel cell vehicle cost components are based on a Strategic Analysis Consultants report prepared for the U.S. Department of Energy.

Table 20 through Table 23 contain the reference scenario breakdown of purchase prices for the various light-duty vehicle archetypes included in the analysis. Because component costs decline as a function of vehicle adoption, these values are in fact model results based on fundamental inputs about the cost of various vehicle components and the potential for those costs to change. Conventional vehicle costs are between $21,556 and $22,923, depending on the energy efficiency of the vehicle archetype. Table 24 shows the assumed energy intensity and Table 25 summarizes the sources used to characterize the vehicle archetypes.

Table 20: Light-duty battery electric vehicles cost breakdown, 2020 CAD

component	2020	2030	2040
battery	18,629	7,415	5,900
motors & electronics	8,298	5,120	5,117
Rest of vehicle	12,145	12,145	12,145
Charging infrastructure equipment	904	892	734
Charging infrastructure installation	615	607	499
total w/o infrastructure	**39,072**	**24,680**	**23,162**
total w/ infrastructure	**40,592**	**26,179**	**24,396**

Table 21: Light-duty plug-in hybrid vehicles cost breakdown, 2020 CAD

component	2020	2030	2040
ICE components	8,603	8,603	8,603
battery	5,970	2,376	1,891
motors & electronics	7,011	4,326	4,323
Rest of vehicle	12,145	12,145	12,145
Charging infrastructure equipment	1,223	1,206	993
Charging infrastructure installation	610	602	495
total w/o infrastructure	**33,729**	**27,451**	**26,962**
total w/ infrastructure	**35,562**	**29,259**	**28,450**

Table 22: Light-duty hybrid vehicles cost breakdown, 2020 CAD

component	2020	2030	2040
ICE components	7,992	7,992	7,992
battery	390	155	123
motors & electronics	5,520	3,406	3,404
Rest of vehicle	12,145	12,145	12,145
total	**26,047**	**23,698**	**23,664**

Table 23: Light-duty fuel-cell electric vehicle cost breakdown, 2020 CAD

component	2020	2030	2040
battery	459	183	145
fuel cell	48,830	46,106	39,009
hydrogen tank	13,964	13,718	12,813
motors & electronics	2,423	1,495	1,494
Rest of vehicle	12,145	12,145	12,145
total	**77,821**	**73,646**	**65,607**

Table 24: Light-duty vehicle archetype energy consumption, MJ/vkm

fuel	gasoline	gasoline efficient	hybrid	plug-in hybrid	battery electric	fuel cell electric
gasoline	2.40	1.77	1.31	0.47	0	0
hydrogen	0	0	0	0	0	1.27
electricity	0	0	0	0.43	0.62	0
total	**2.40**	**1.77**	**1.31**	**0.90**	**0.62**	**1.27**

Table 25: Light-duty vehicle archetype information sources

Item	Source
Other common components costs and vehicle power	Idaho National Laboratory. (2015). *Vehicle Lightweighting: 40% and 45% Weight Savings Analysis*.
ICE vehicle components costs	Idaho National Laboratory. (2015). *Vehicle Lightweighting: 40% and 45% Weight Savings Analysis*.
2015 new gasoline technology energy efficiency	NRCan. (2015). Fuel Consumption Guide 2015.
ICE vehicle efficiency improvements costs and consumption	Energy Information Administration. (2019). *National Energy Modeling System Documentation: Transportation Demand Module*.
Maintenance costs	2°Institute. (2018). *Comparing Fuel and Maintenance Costs of Electric and Gas Powered Vehicles in Canada*.
Battery costs trajectory	Bloomberg. (2020). *Electric Vehicle Outlook*.
Electric vehicle component costs except batteries	UBS. (2017). *UBS Evidence Lab Electric Car Teardown - Disruption Ahead?*
Hybrid and plug-in hybrid component breakdown and equipment sizes	Argonne National Laboratory. (2016). *Assessment of vehicle sizing, energy consumption and cost through lage scale simulation of advanced vehicle technologies*.
Hybrid vehicle efficiency	Oak Ridge National Laboratory. (2017). *Fuel consumption sensitivity of conventional and hybrid electric light-duty gasoline vehicles to driving style*.
Plug-in electric vehicles efficiencies	NRCan. (2019). *Fuel Consumption Guide 2019*.
Plug-in hybrid fuel consumption breakdown	Plotz et al. (2017). *CO_2 mitigation potential of plug-in electric vehicles larger than expected*.
Electric charging infrastructure costs	Conversations and email exchanges with Transport Canada that occurred in 2021.
Fuel cell stack and system costs trajectories	SA Consultants. (2017). *Mass Production Cost Estimation of Direct H2 PEM Fuel Cell Systems for Transportation Applications: 2016 Update.*

Item	Source
Hydrogen tank costs trajectory	SA Consultants. 2016. *Final Report: Hydrogen Storage System Cost Analysis*.
Hydrogen vehicle energy efficiency	Fueleconomy.gov. (2019). *Compare Fuel Cell Vehicles*.

Assumptions for medium-duty vehicles

The model includes four medium-duty vehicle archetypes that use internal combustion engines, three of which are diesel fueled, with the fourth fueled by compressed natural gas. It also includes archetypal hybrid, plug-in hybrid, battery electric, and fuel cell vehicles. A survey and literature review conducted in 2019 shows that most medium-duty vehicles fit within the smaller weight classes (3 to 5), which are characterized by power outputs close to 170 kW. The daily driving range is sourced from the same survey.

Most medium-duty vehicle costs are based on the National Renewable Energy Laboratory (NREL) FASTSim model inputs with some adjustments to the battery cost and fuel cell drivetrain cost. These larger commercial vehicles are expected to require more advanced charging infrastructure than personal light-duty vehicles. Costs are based on charging infrastructure costs for local operations as reported by the ICCT in 2019.

Medium-duty vehicle energy intensities are inferred from the energy intensities of heavy-duty vehicle technology archetypes. For example, if the heavy-duty fuel cell technology is 60% more efficient than the base heavy-duty diesel technology, then the same relative energy intensity is applied for the medium-duty fuel cell vehicle archetype.

Battery costs are based on Bloomberg's electric vehicle outlook publications, and battery energy density is assumed to improve by 2% per year between 2015 and 2025, after which it remains constant.

The energy consumption of freight vehicles is shown in megajoules per tonne kilometre (MJ/tkm). The energy consumed per vehicle kilometre is calculated by multiplying MJ/tkm by the tonnes of freight moved per vehicle. We assume that medium-duty vehicles move 1.3 tonnes of freight on average each, consistent with NRCan CEUD data. Therefore, a new diesel vehicle consumes 7.2 MJ/km (equivalent to around 19 L/100 km).

Table 26 through Table 30 contain the vehicle archetype price breakdown. Again, these are model results that are a function of battery and other component cost reductions that occur in the simulation. Table 31 presents the energy intensity of the medium-duty vehicle archetypes and Table 32 provides more detail on the information sources used to characterize these technologies.

Table 26: Medium-duty ICE vehicle cost breakdown, 2020 CAD

component	Diesel	Diesel, efficient	Diesel, high eff.	CNG
ICE components	23,708	29,417	31,276	34,973
other common	44,163	44,163	44,163	44,163
Fueling infrastructure equipment	0	0	0	16,561
Fueling infrastructure installation	0	0	0	5,520
total w/o infrastructure	**67,871**	**73,580**	**75,439**	**79,136**
total w/ infrastructure	**67,871**	**73,580**	**75,439**	**101,218**

Table 27: Medium-duty battery electric vehicle cost breakdown, 2020 CAD

component	2020	2030	2040
battery	46,235	18,403	14,643
motors & electronics	15,427	9,519	9,513
Rest of vehicle	44,163	44,163	44,163
Charging infrastructure equipment	39,858	39,415	27,329
Charging infrastructure installation	9,964	9,964	9,964
total w/o infrastructure	**105,825**	**72,085**	**68,320**
total w/ infrastructure	**155,648**	**121,465**	**105,614**

Table 28: Medium-duty plug-in hybrid vehicles cost breakdown, 2020 CAD

component	2020	2030	2040
ICE components	21,240	21,240	21,240
battery	19,090	7,598	6,046
motors & electronics	18,920	11,674	11,667
Rest of vehicle	44,163	44,163	44,163
Charging infrastructure equipment	39,850	39,408	27,324
Charging infrastructure installation	9,968	9,968	9,968
total w/o infrastructure	**103,413**	**84,676**	**83,117**
total w/ infrastructure	**153,232**	**134,052**	**120,409**

Table 29: Medium-duty hybrid vehicles cost breakdown, 2020 CAD

component	2020	2030	2040
ICE components	31,623	31,623	31,623
battery	1,811	721	573
motors & electronics	8,904	5,494	5,491
Rest of vehicle	44,163	44,163	44,163
total	**86,501**	**82,001**	**81,850**

Table 30: Medium-duty fuel-cell electric vehicle cost breakdown, 2020 CAD

component	2020	2030	2040
battery	442	176	140
fuel cell	80,624	76,126	64,409
hydrogen tank	15,760	15,482	14,461
motors & electronics	15,427	9,519	9,513
Rest of vehicle	44,163	44,163	44,163
total	**156,416**	**145,467**	**132,686**

Table 31: Medium-duty vehicle archetype energy consumption, MJ/tonne km travelled

	diesel	diesel efficient	diesel high eff.	CNG	hybrid	battery electric	Plug-in hybrid	fuel cell electric
diesel	5.50	4.70	4.21	0	3.76	0	0	1.33
natural gas	0	0	0	5.56	0	0	0	0
hydrogen	0	0	0	0	0	0	2.49	0
electricity	0	0	0	0	0	1.39	0	0.90
total	**5.50**	**4.70**	**4.21**	**5.56**	**3.76**	**1.39**	**2.49**	**2.23**

Table 32: Medium-duty vehicle archetype information sources

Item	Source
Medium-duty vehicle cost component breakdown	NREL. (2019). Market segmentation analysis of medium and heavy-duty trucks with a fuel cell emphasis
Fuel consumption and engine sizes	ICCT. (2017). *Transitioning to zero-emission heavy-duty freight vehicles*. (efficiency improvement applied relative to base diesel technology, which is itself based on the CIMS model)
Maintenance costs	ATRI. (2018) . *An analysis of operational costs of trucking: 2018 Update*; Earl et al. (2018). *Analysis of long haul battery electric trucks in EU*. (costs calculated relative to heavy-duty)
Natural gas technology infrastructure costs	US Department of Energy. (2014). *Costs associated with compressed natural gas vehicle fueling infrastructure* with Navius calculations.
Electric charging infrastructure costs	ICCT. (2019). *Estimating the infrastructure needs and costs for the launch of zero-emission trucks*.
Battery costs trajectory	Bloomberg. (2020). *Electric Vehicle Outlook*.
Fuel cell stack, system, and hydrogen tank costs trajectory	SA Consultants. (2019). *2019 DOE Hydrogen and Fuel Cells Program Review Presentation*.
Medium-duty vehicle fleet breakdown	Navius Research. (2019). *British Columbia's medium and heavy-duty vehicle characterization*. Confidential report.

Assumptions for heavy-duty vehicles

The model includes four internal combustion engine vehicle technologies, of which three are diesel, and one is natural gas, as well as a battery electric and a fuel cell vehicle technology each in the heavy-duty sector. The model's heavy-duty vehicle archetypes are mostly based on a 2017 ICCT report. The trucks are all assumed to have a 350-kW engine or motor, as per the publication. The daily driving range is inferred from the survey of British Columbia's medium and heavy-duty fleet that Navius conducted in 2019.

The vehicle cost breakdowns are estimated both using the ICCT 2017 report and a 2017 paper written by Fries M. et al. Battery costs and fuel cell system costs are based on Bloomberg and Strategic Analysis Consultants' work, respectively. Battery energy density is assumed to improve by 2% per year between 2015 and 2025, after which it remains constant.

The energy intensities for the heavy-duty vehicle technology archetypes shown below are all inferred from ICCT's 2017 report. As with medium-duty vehicles, advanced charging infrastructure costs are also included for plug-in technologies. We assume that 30% of heavy-duty vehicles are used for long-haul transport and 70% for local operations. The ICCT finds that long-haul operation will likely require higher infrastructure costs, hence the higher estimate relative to the exclusively locally operated medium-duty vehicle cost.

We estimate that a battery electric class 8 tractor weighs 11% more than a diesel tractor. Heavy-duty vehicles are restricted to a maximum weight for safety and infrastructure capacity limits, which means that any extra tractor weight reduces the hauling capacity. We therefore apply an 11% markup to the heavy-duty battery electric archetype to account for this disadvantage.

We use Natural Resources Canada's Comprehensive Energy Use Database and adjust it with the daily distance travelled estimated from our survey to infer that heavy-duty vehicles transport about 9.7 tonnes of freight on average over each km.

Table 33 through Table 35 contain the vehicle archetype price breakdown. As with other vehicle types, these are model results that are a function of battery and other component cost reductions that occur in the simulation. Table 36 presents the energy intensity of the heavy-duty vehicle archetypes and Table 37 provides more detail on the information sources used to characterize these technologies.

Table 33: Heavy-duty ICE vehicle cost breakdown, 2020 CAD

component	Diesel	Diesel, efficient	Diesel, high eff.	LNG
ICE components	102,406	107,065	114,999	133,053
other common	82,806	82,806	82,806	82,806
Fueling infrastructure equipment	0	0	0	23,321
Fueling infrastructure installation	0	0	0	7,774
total w/o infrastructure	**185,212**	**189,871**	**197,805**	**215,859**

total w/ infrastructure	**185,212**	**189,871**	**197,805**	**246,954**

Table 34: Heavy-duty battery electric vehicle cost breakdown, 2020 CAD

component	2020	2030	2040
battery	219,197	87,246	69,424
motors & electronics	31,778	19,609	19,597
Rest of vehicle	82,806	82,806	82,806
Charging infrastructure equipment	261,620	252,880	182,462
Charging infrastructure installation	21,402	21,402	21,402
total w/o infrastructure	**333,781**	**189,661**	**171,827**
total w/ infrastructure	**616,803**	**463,942**	**375,691**

Table 35: Heavy-duty fuel-cell electric vehicle cost breakdown, 2020 CAD

component	2020	2030	2040
battery	1,231	490	390
fuel cell	165,990	156,731	132,606
hydrogen tank	43,892	43,117	40,273
motors & electronics	11,246	6,939	6,935
Rest of vehicle	82,806	82,806	82,806
total	**305,165**	**290,083**	**263,010**

Table 36: Heavy-duty vehicle archetype energy consumption, MJ/tonne km travelled

	diesel	diesel efficient	diesel high eff.	LNG	battery electric	fuel cell electric
diesel	1.48	1.38	1.06	0	0	0
natural gas	0	0	0	1.48	0	0
hydrogen	0	0	0	0	0	0.93
electricity	0	0	0	0	0.56	0
total	**1.48**	**1.38**	**1.06**	**1.48**	**0.56**	**0.93**

Table 37: Heavy-duty vehicle archetype information sources

Item	Source
Heavy-duty vehicle other common cost components	ICCT. (2017). *Transitioning to zero-emission heavy-duty freight vehicles*.
Fuel consumption and engine sizes	ICCT. (2017). *Transitioning to zero-emission heavy-duty freight vehicles*.
Conventional technology vehicle component costs except infrastructure	ICCT. (2017). *Transitioning to zero-emission heavy-duty freight vehicles*; Fries et al. (2017). *An Overview of Costs for Vehicle Components, Fuels, Greenhouse Gas Emissions and Total Cost of Ownership Update 2017*
Maintenance costs	ATRI. (2018) . *An analysis of operational costs of trucking: 2018 Update*; Earl et al. (2018). *Analysis of long haul battery electric trucks in EU*.
Natural gas technology infrastructure costs	US Department of Energy. (2014). *Costs associated with compressed natural gas vehicle fueling infrastructure* with Navius calculations.

Item	Source
Electric charging infrastructure costs	ICCT. (2019). *Estimating the infrastructure needs and costs for the launch of zero-emission trucks*.
Battery costs trajectory	Bloomberg. (2020). *Electric Vehicle Outlook*.
Fuel cell stack, system, and hydrogen tank costs trajectory	SA Consultants. (2019). *2019 DOE Hydrogen and Fuel Cells Program Review Presentation*.
Heavy-duty vehicle fleet breakdown trajectory	Navius Research. (2019). *British Columbia's medium and heavy-duty vehicle characterization*. Confidential report.

Industrial heat pumps

Heat pumps use energy to run a refrigeration cycle which is the compression and expansion of a fluid. This cycle moves energy in the form of heat from a lower-temperature source to a higher-temperature sink. Both thermal energy (e.g. waste heat, heat from combustion) and mechanical energy can drive the refrigeration cycle, where the quantity of energy transferred is typically much larger than the quantity of energy consumed by the heat pump. The focus of this research work is on mechanical heat pumps that use compression to drive the refrigeration cycle, with the compressor typically powered by an electric motor.

Although the most familiar application of heat pumps is for space and water heating in buildings, high capacity heat pumps can also be used in industry to provide heat for industrial processes. Industrial heat pumps can draw heat from several sources with a range of temperatures, from ambient air and water to process cooling water and process waste heat. Industrial heat pumps do not just provide passive heat recovery, but like their applications in buildings they take energy from a source and supply it at a higher temperature to the sink.

Currently, industrial heat pumps are not widely used. Barriers to their adoption include:

- **A lack of knowledge** about industrial heat pump technologies and a lack of attention to heat consumption within industrial facilities.
- **The high upfront costs** and long-payback periods. While heat pumps may reduce energy costs, their initial investment cost is higher than for a fossil fuel-fired boiler or heater. At current energy prices and with low (or no) cost for carbon emissions, industrial heat pumps are often not cost-competitive with gas-fired heat.

- **The limits on their supply temperature.**[36] Commercially available industrial heat pumps generally only provide heat at temperatures up to 100 ºC, though new technologies could raise this maximum to 140 ºC.[37]

Within the limits of their supply temperature, industrial heat pumps may be used for a range of end-uses that include drying, cooking, distillation, washing, and pre-heating. Case studies from Canada, Austria, Germany, France, and Denmark provide 42 examples of industrial mechanical heat-pumps used in a variety of manufacturing sectors (Table 38).[38] Each application is characterized by its coefficient of performance COP, which is a measure of how much heat is provided to the sink divided by the amount of energy used to move that heat from the source. The case studies are also characterized by their sink and source (i.e. supply) temperatures.

The COP depends the design of the heat pump and the on source and sink temperatures, with the difference in temperature know as the "lift".[39] The case studies provide examples that are currently economically viable, and they tend to have high COPs associated with smaller lifts and lower supply temperatures. Wider application of industrial heat pumps should see them used with larger lifts and higher supply temperatures (e.g. supply at 90-100 ºC, with a lift of 50-70 ºC). These conditions would result in lower COPs ranging from 2 to 3.[40] For example, commercially available heat pumps for lumber drying use ambient air to heat lumber kilns to temperatures as hot as 116 ºC. These systems use 40-60% less energy than a direct or steam heated kiln.[41] If the conventional system is 85% energy efficient, this energy savings implies a COP between 1.4 and 2.2.

---

[36] International Energy Agency Heat Pump Centre (2014), *Application of Industrial Heat Pumps, Part 1 Final Report*

[37] Wolf, S., Lambauer, J., Blesl, M., Fahl, U., Voß A. (2002).*Industrial Heat Pumps in Germany: Potentials, Technological Development and Market Barrier,* European Council for an Energy Efficient Economy, Summer Study on Energy Efficiency in Industry

[38] International Energy Agency Heat Pump Centre (2014), *Application of Industrial Heat Pumps, Part 2 Final Report*

[39] Ommen, T., Jensen, J.K., Markussen, W.B., Reinhold, L., Elmegaard, B. (2015) *Technical and Economic Working Domains of Industrial Heat Pumps: Part 1 - Single Stage Vapour Compression Heat Pump*, International Journal of Refrigeration, 55, 168-182

[40] Ibid.

[41] Nyle Systems, Lumber Drying Systems: Very High Temperature Dehumidification Systems, www.nyle.com/lumber-drying-systems/lumber-kiln-drying/dehumidifcation-kilns/vht-dh-systems/

Table 38: Summary of industrial heat-pump case-studies

Sector	Number of examples	Range of COPs	Range of source temp. (°C)	Range of sink (i.e. supply) temp. (°C)
Food & beverage	20	3.4 to 10.7	-10 to 38	55 to 90
Other manufacturing*	14	3.5 to 5.6	22 to 43	50 to 87
Chemical manufacturing	3	3.7 to 5.0	18 to 35	45 to 60
Forest products	2	3 to 4	45	55 to105
Metal manufacturing	2	4.3	36	70
Pulp and paper	1	5.0	40	68

*Other manufacturing includes automotive, mechanical, metal processing, textiles

The archetype of industrial heat pumps in gTech provides low-temperature heat for industry, based on a closed-cycle mechanical compression using electricity to drive the refrigeration cycle. The capital cost and COP of this archetype depend on the assumed temperature lift and supply temperature: larger lifts and higher supply temperatures will have higher capital costs and lower COP.[42] The archetype is based on a system that would apply across the broadest range of end-uses, with high supply temperatures (90-100 °C) and lift (70 °C). Under these conditions the COP is 2.5 and the capital cost is 840 $/kW (2010 CAD),[43] roughly three and a half times higher than for a natural gas combustion boiler (Table 39).

Table 39: gTech inputs for an industrial heat pump compared to a natural-gas boiler

Technology	Capital Cost (2010 CAD/kW)	Electricity, $GJ/GJ_{thermal}$	Natural gas, $GJ/GJ_{thermal}$
Industrial heat pump	838	0.4	-
Efficient gas boiler	233	-	1.1

We assume the industrial heat pump technology in gTech can supply heat to a maximum of 100 °C. Table 40 summarizes the share of heat demand that is 100 °C or less by sector. For most sectors, this share is based on a study of German industries that characterized heat consumption by sector and temperature.[44] Our assumption is that the temperature profile of heat demand by sector is the same in Canada (e.g. if 45% of the heat required for food and beverage manufacturing is at or below 100 °C in Germany, we assume that this fraction is representative for Canada). The fraction of

42 Ommen, T., Jensen, J.K., Markussen, W.B., Reinhold, L., Elmegaard, B. (2015) *Technical and Economic Working Domains of Industrial Heat Pumps: Part 1 - Single Stage Vapour Compression Heat Pump*, International Journal of Refrigeration, 55, 168-182

43 Ibid.

44 German Energy Agency (DENA) (2016), *Process Heat in Industry and Commerce: Technology Solutions for Waste Heat Utilisation and Renewable Provision*

heat below 100 °C in the forest products manufacturing sector (e.g. lumber and structural panels) is based on the fraction of thermal energy used for product drying estimated by Natural Resources Canada.[45]

Table 40: Modelling assumptions for the fraction of industrial heat demanded at less than or equal to 100 °C, by sector

Sector	% of heat demand <= 100 °C
Food & beverage manufacturing, agriculture processing	45%
Other manufacturing	30%
Chemical and biofuel manufacturing	15%
Forest products	85%
Pulp and paper	20%
Mineral and metal mining	100%

Direct-air carbon capture

Direct air capture (DAC) is a new negative emissions technology that extracts CO_2 directly from the atmosphere. DAC could play an important role in achieving future emissions reductions goals, such as the targets set out in the Paris Agreement.

Several DAC companies are currently in operation, such as Carbon Engineering in Squamish, BC. There are two technologies currently used for DAC. Air is either passed through a high temperature liquid sorbent, or a low temperature solid sorbent that both bind the CO2 from the air.[46] In both cases, DAC is currently an energy intensive process that requires both electricity, for fans and compressors, and heat, to regenerate the sorbet. While the heat may be electrified in the future, most current cost estimates assume the use of natural gas combustion, where the combustion emissions are captured along with atmospheric CO_2.

The future costs of DAC are uncertain, but all sources reviewed expect the cost of DAC to decline over time. In gTech, we estimate the cost of DAC using a declining capital cost function, where the upfront costs declines as a function of the cumulative deployment of the technology. The function was estimated from harmonizing cost estimates made by Fasihi et al. (2019), Larsen et al., (2019), and Keith et al.

[45] Natural Resources Canada (2009), *Status of Energy Use in the Canadian Wood Products Sector*

[46] IEA (2020). *Direct Air Capture*, IEA, Paris https://www.iea.org/reports/direct-air-capture

(2019).[47,48,49] While these sources use differing assumptions when calculating DAC costs, the costs communicated here and input to the model are based on the following assumptions:

- Discount rate of 15%
- 30 year lifespan
- 90% capacity utilization
- Natural gas price of $2.6/GJ (2015 CAD) and an electricity price of $95/MWh (2015 CAD) (for the sake of illustration in this report. Actual energy costs are determined for each region during the model simulation).

Figure 24 shows the cost of DAC per tonne of CO_2 reduced for each of the sources in with three different levels of technology deployment (first of a kind facility, early commercialization (8 $MtCO_2$ captured per year) and full commercialization (over 1.5 $GtCO_2$ captured per year). The figure disaggregates the cost of DAC into capital costs, fixed operating costs, variable operating costs, and fuel costs (natural gas and electricity). All sources examined expect DAC costs to decline over time with ongoing deployment. DAC cost estimates in the studies examined differ significantly, ranging from CAD 303 to CAD 1,295 per tonne of CO_2 reduced for a 1st of a kind plant in the reference case. In the long-term, estimates range from CAD 99 to CAD 142 per tonne of CO_2 reduced.

47 Fasihi et al., (2019). Techno-economic assessment of CO2 direct air capture plants. Journal of Cleaner Production, 224, 957-980.

48 Larsen et al. (2019). Capturing Leadership, Policies for the US to Advance Direct Air Capture Technology. Rhodium Group.

49 Keith et al., (2018). A process for Capturing CO2 from the Atmosphere. Joule, 2, 1-22.

Figure 24: Direct air capture abatement cost estimates from the literature

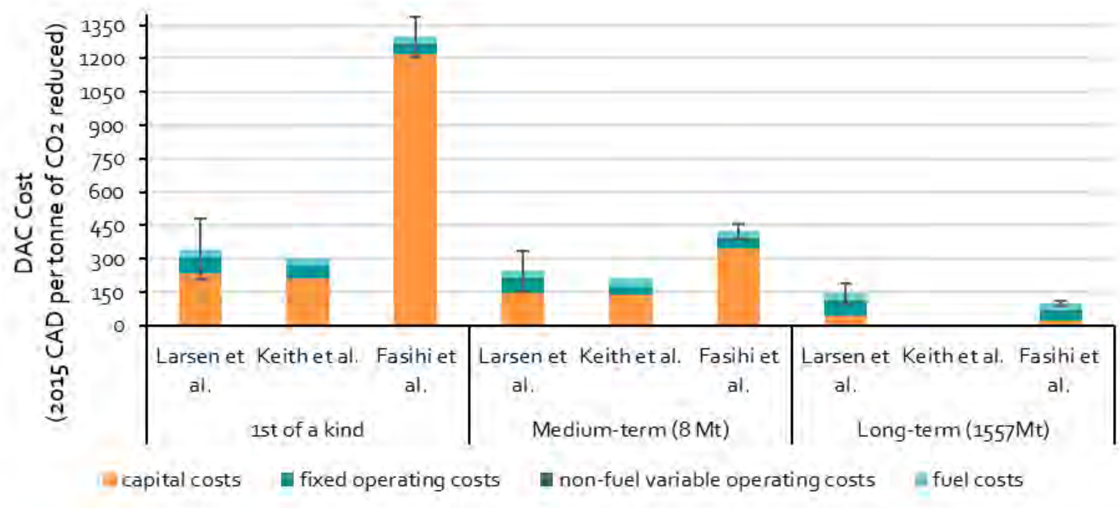
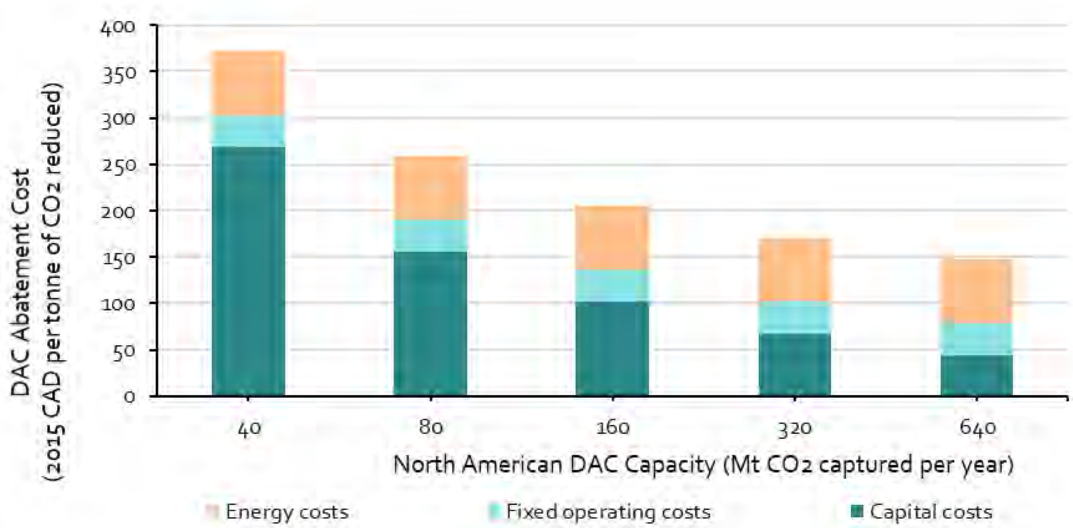


Figure 25 shows the DAC cost inputs used in this analysis. During early commercialization, the abatement cost is about \$370/tCO_2 (with about 30 Mt captured per year in North America). If the technology see substantial deployment, abatement costs may fall to as low as \$150/tCO_2 (e.g., with more than 600 Mt captured annually in North America). In all cases, costs are dominated by capital expenditures.

Figure 25: Direct air capture abatement cost inputs to the analysis



Appendix B: Building Sector Technology Assumptions

Building envelopes

The building envelope technology archetypes for the British Columbia (BC) region of the gTech model were developed in cooperation with RDH Building Science. The archetypes characterize BC's existing building stock and the thermal improvements associated with current and future building codes.

Building envelopes are disaggregated into nine building types, three vintages and three levels of new construction as shown in Table 41 and Table 42. Note that low-rise and high-rise apartment buildings are aggregated. RDH provided the data for these archetypes in three regions of BC (lower mainland, Kamloops and Prince George). These archetypes were aggregated to form a single representative region for use in gTech. Additional modifications to the archetypes were made to ensure that total floor space and demand for space conditioning aligned with Natural Resources Canada's Comprehensive Energy Use Database.

The costs are the portion attributed to the relevant elements of the building envelope and do not represent full construction costs. The costs for existing building envelopes are the cost to perform a comprehensive retrofit of the building envelope as would be required to meet new construction performance targets (i.e. a deep energy retrofit with a significant reduction, about 50%, in heating required). RDH's general description of their approach in developing the archetypes is in the Appendix. Additional detail by archetype can be provided upon request.

Table 41: Residential building envelope archetypes

Building type	Archetype	Heating intensity (GJ/m²/yr)	Cooling intensity (GJ/m²/yr)	Cost (2018$/m²)
Single-family detached	pre-1980*	0.3869	0.0061	$540
	post-1980*	0.2688	0.0095	$540
	post-2000*	0.1691	0.0079	$540
	new standard	0.0840	0.0079	$709
	new efficient	0.0773	0.0079	$722
	new near zero	0.0308	0.0079	$797
Attached	pre-1980*	0.3040	0.0081	$421
	post-1980*	0.2112	0.0127	$421
	post-2000*	0.1329	0.0107	$421
	new standard	0.0751	0.0107	$553
	new efficient	0.0729	0.0107	$569
	new near zero	0.0241	0.0107	$618
Apartment	pre-1980*	0.1894	0.0028	$605
	post-1980*	0.1564	0.0028	$605
	post-2000*	0.0880	0.0040	$605
	new standard	0.0880	0.0040	$722
	new efficient	0.0640	0.0040	$737
	new near zero	0.0255	0.0040	$818

* cost for existing archetypes is retrofit costs to new standard efficiency envelope

Table 42: Commercial building envelope archetypes

Building type	Archetype	Heating intensity (GJ/m²/yr)	Cooling intensity (GJ/m²/yr)	Cost (2018$/m²)
Food retail	pre-1980*	1.0758	0.2548	$784
	post-1980*	1.0397	0.2594	$784
	post-2000*	0.1707	0.3653	$784
	new standard	0.1707	0.5461	$844
	new efficient	0.1004	0.4285	$865
	new near zero	0.0901	0.3677	$908
Office	pre-1980*	0.3491	0.1450	$493
	post-1980*	0.2577	0.1628	$493
	post-2000*	0.2048	0.1672	$493
	new standard	0.2048	0.0701	$715
	new efficient	0.1505	0.0550	$726
	new near zero	0.0883	0.0520	$759
Warehouse	pre-1980*	0.4481	0.0801	$270
	post-1980*	0.4049	0.0801	$270
	post-2000*	0.2206	0.0638	$270
	new standard	0.2206	0.0496	$391
	new efficient	0.1621	0.0339	$395
	new near zero	0.0952	0.0305	$410
Retail	pre-1980*	0.6949	0.0988	$498
	post-1980*	0.6392	0.1052	$498
	post-2000*	0.2766	0.1092	$498
	new standard	0.1707	0.0634	$537
	new efficient	0.1004	0.0497	$552
	new near zero	0.0901	0.0427	$587
Schools	pre-1980*	0.3606	0.0881	$353
	post-1980*	0.2877	0.0802	$353
	post-2000*	0.2325	0.0821	$353
	new standard	0.4430	0.1131	$641
	new efficient	0.1867	0.0541	$660
	new near zero	0.0876	0.0485	$705

Building type	Archetype	Heating intensity (GJ/m2/yr)	Cooling intensity (GJ/m2/yr)	Cost (2018$/m2)
Other	pre-1980*	0.2629	0.0581	$483
	post-1980*	0.2212	0.0611	$483
	post-2000*	0.1376	0.0660	$483
	new standard	0.1376	0.0581	$634
	new efficient	0.0771	0.0428	$645
	new near zero	0.0489	0.0378	$678

* cost for existing archetypes is retrofit costs to new standard efficiency envelope

Building floor area by type

The share of building floor area by building type (e.g. apartment, single family detached home) is a result of gTech rather than an input. Nonetheless, this result can be calibrated to expectations, such as an increasing share of residential building floor area in higher density building types (Table 43). The fraction of commercial and institutional floor area by building type is constant over time as gTech does not disaggregate the services sector into subsectors and all segments grow at the same rate (Table 44, showing the trend to 2030).

Table 43: Residential building area by building type (%)

	2015	2020	2025	2030	2035	2040
Apartment	31%	31%	32%	32%	33%	34%
Attached homes	12%	14%	15%	17%	18%	20%
Detached homes	58%	57%	56%	54%	53%	52%

Table 44: Commercial and institutional building area by building type (%)

	2015	2020	2025	2030	2035	2040
Food Service	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
Offices	37.8%	37.8%	37.8%	37.8%	37.8%	37.8%
Other	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%
Retail	16.6%	16.6%	16.6%	16.6%	16.6%	16.6%
Schools and Education	13.2%	13.2%	13.2%	13.2%	13.2%	13.2%

Mechanical systems

Space and water heating archetypes are based on data from the US Energy Information Administration[50] and National Renewable Energy Laboratory[51]. These archetypes are shown in Table 45, Table 46 and Table 47. Costs for the residential technologies are given as costs for a unit sized for an individual household. The output attribute of each archetype represents typical utilization of each technology: the quantity of heating provided, or the volume of hot water provided (with a 46.5 ºC temperature lift). Space cooling is a relatively small energy end-use in British Columbia and the space cooling technology archetypes are not currently included in this report.

Table 45: Residential space heating technology archetypes

End-use	Archetype	Capital cost (2018$)	Energy Efficiency (GJ_{out}/GJ_{in})	Output (GJ/yr)
Space heating*	Standard efficiency gas furnace	$4,746	90%	36.2
	Condensing gas furnace	$5,284	98%	36.2
	Electric baseboard	$3,040	100%	36.2
	Standard efficiency ASHP	$5,702	2.4	36.2
	High efficiency ASHP	$7,137	2.6	36.2
	High efficiency NGHP	$18,345	1.3	36.2

* equipment life is assumed to be 20 years for space heating

50 Energy Information Administration. 2016. Analysis & Projections: Updated Buildings Sector Appliance and Equipment Costs and Efficiency. Available from: https://www.eia.gov/analysis/studies/buildings/equipcosts/

51 National Renewable Energy Laboratory. 2018. National Residential Efficiency Measures Database. Accessed from: https://remdb.nrel.gov/

Table 46: Residential water heating technology archetypes

End-use	Archetype	Capital cost (2018$)	Energy Efficiency (GJ_{out}/GJ_{in})	Output (m^3/yr)
Water heating*	Standard efficiency gas water heater with tank	$705	59%	82.0
	High efficiency gas water heater with tank	$819	67%	82.0
	Standard efficiency electric water heater with tank	$671	92%	82.0
	High efficiency electric water heater with tank	$739	95%	82.0
	Standard efficiency ASHP water heater	$2,274	2.0	82.0
	Standard efficiency tankless gas water heater	$1,706	82%	82.0
	High efficiency tankless gas water heater	$2,161	96%	82.0

* equipment life is assumed to be 9 years for water heating

Table 47: Commercial space and water heating technology archetypes

End-use	Archetype	Capital cost (2018$/$m^2$)	Energy Efficiency (GJ_{out}/GJ_{in})	Output (GJ/m^2/yr)
Space heating*	Standard efficiency gas boiler	$10.06	80%	0.35
	High efficiency gas boiler	$10.67	85%	0.35
	Condensing gas boiler	$11.29	98%	0.35
	Standard efficiency electric boiler	$5.46	98%	0.35
	High efficiency GSHP	$41.91	5.0	0.35
	High efficiency ASHP	$14.09	3.2	0.35
Water heating*	Standard efficiency gas water heater with tank	$1.47	80%	0.10
	Condensing gas water heater with tank	$1.73	99%	0.10
	Standard efficiency electric water heater with tank	$1.61	98%	0.10
	Standard efficiency ASHP water heater	$4.90	2.0	0.10

* equipment life is assumed to be 25 years for space heating and 10 years for water heating

Major appliances

Table 48 and Table 49 show the technology assumptions for fridges and freezers. The technologies are based on data from the National Renewable Energy Laboratory.[52] The archetype of "existing" technology stock is calibrated to the NRCAN Comprehensive Energy Use Database (CEUD).[53] The energy consumption of electric and gas ranges are also calibrated to NRCAN's estimate for total stock and new stock in the CEUD (Table 50). The energy consumption of the induction range is based on a doubling of the cooktop energy efficiency, but with the cooktop only accounting for 35% of a range's annual energy consumption (remainder from oven).

The energy intensity of the existing stock of dishwashers and clothes washers is calibrated to the NRCAN CEUD (Table 51, Table 52). New stock represents units that are compliant with regulations. New efficient archetypes are based on units that represent the most efficient models available. Note that most energy related to clothes washing is consumed by the clothes dryers, with the intensity of drying related to the amount of water removed in the clothes washer. gTech currently does not represent how a more efficient clothes washer also reduces clothes drying energy consumption. The energy intensity of drying is calibrated to the NRCAN CEUD and clothes drying energy consumption is roughly proportional to the number of households in a forecast.

Note that gTech also includes energy (primarily electricity) consumption for other appliances and electronics. The quantity of electricity consumed is roughly proportional to the number of households in a forecast.

Table 48: Residential refrigerator technology archetypes

End-use	Archetype	Capital cost (2018$)	Energy Consumption (GJ/yr)
Refrigeration*	Existing	$922	2.00
	Standard Efficiency	$922	1.80
	Medium Efficiency	$1,090	1.43
	High Efficiency	$1,247	1.35

* equipment life is assumed to be 17 years for refrigeration

52 NREL. National Residential Efficiency Measures Database. Accessed on October 18, 2017 from: https://www.nrel.gov/ap/retrofits/about.cfm

53 Natural Resources Canada, Comprehensive Energy Use Database, http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm

Table 49: Residential freezer technology archetypes

End-use	Archetype	Capital cost (2018$)	Energy Consumption (GJ/yr)
Freezers*	Existing	$519	1.46
	New	$524	1.35
	High Efficiency	$553	1.24

* equipment life is assumed to be 21 years for freezers

Table 50: Cooking range technology archetypes

End-use	Archetype	Capital cost (2018$)	Energy Consumption (GJ/yr)
Ranges*	Electric, high efficiency/induction	$1,300	1.54
	Electric, new	$600	1.88
	Electric, existing	$600	2.39
	Natural gas, existing	$700	4.43
	Natural gas, new	$700	4.41

* equipment life is assumed to be 20 years for ranges

Table 51: Dishwasher technology archetypes

End-use	Archetype	Capital cost (2018$)	Electrical Energy Consumption (GJ/yr)	Hot Water Consumption (m^3/yr)
Dishwashers*	Existing	$746	0.44	4.6
	New efficient, EF58	$756	0.29	3.4
	New most efficient, EF 94	$1,708	0.06	2.8

* equipment life is assumed to be 12 years for dishwashers

Table 52: Clothes washer technology archetypes

End-use	Archetype	Capital cost (2018$)	Electrical Energy Consumption (GJ/yr)	Hot Water Consumption (m^3/yr)
Clothes washers*	Existing	$613	0.32	8.2
	New, compliant with regulation (MEF~39)	$613	0.23	7.4
	New, efficient (MEF~67)	$764	0.07	1.4

* equipment life is assumed to be 12 years for clothes washers

Lighting

Table 53 shows the residential lighting technology archetypes. The archetypes are based on a 60W equivalent (roughly 850 lumens) serving 3.4 m^2 and operating for 652 hours/yr. The capital cost and energy consumption for commercial and institutional lighting is expressed per m^2 of floor area served (Table 54).

Table 53: Residential lighting technology archetypes

	Capital cost per 60W equivalent (2018$)	GJ/yr per 60W equivalent
Incandescent	0.25	0.041
Halogen	1.99	0.030
Compact fluorescent	2.74	0.009
LED	7.53	0.006

Table 54: Commercial and institutional lighting technology archetypes

	Capital cost per m^2 of floor space served (2018$)	GJ/yr m^2 of floor space served
Existing	14	0.15
New	14	0.10
New efficient	21	0.06

At Navius, we offer our clients the confidence to make informed decisions related to energy, the economy, and the environment.

We take a collaborative approach to projects, drawing on a unique suite of modeling, research and communication tools to provide impartial analysis and clear advice.

Contact us

Navius Research
contact@naviusresearch.com
www.naviusresearch.com

Appendix G: December 2020 Load Forecast Tables

Table G-1 – Temperature Normalized Actuals and December 2020 Reference Load Forecast Before Adjustments

Total Hydro	December 2020 Load Forecast - BEFORE RATE IMPACTS														
	Resid-ential Sales (GWh)	Commercial Sales (GWh)	Light Industrial (GWh)	Commercial/ Light Industrial[1] (GWh)	Large Industrial Sales (GWh)	Irrig Str Lt BCH Own Use Sales (GWh)	Total BC Hydro Service Area Sales (GWh)	Sales to City of New Westminster & FortisBC Electric Sales (GWh)	Sales to Seatle City Light Hyder, Alaska Sales (GWh)	Total Firm Sales (GWh)	Total System Losses (GWh)	Total Gross System Require-ments (GWh)	Losses % of Total Sales (GWh)	Integrated Total Gross System Require-ments (GWh)	Total Domestic Sales (GWh)
Temperature Normalized Actuals															
F2015	17,973	14,460	4,227	18,687	14,055	369	51,084	966	306	52,356	4,380	56,736	8.4%	56,407	52,283
F2016	18,019	14,257	4,148	18,405	13,698	393	50,515	971	309	51,795	5,531	57,326	10.7%	56,997	51,724
F2017	17,952	14,582	4,275	18,857	13,106	381	50,296	1,053	319	51,668	5,195	56,863	10.1%	56,535	51,599
F2018	17,997	14,513	4,364	18,877	13,513	382	50,769	1,016	313	52,098	5,547	57,645	10.6%	57,316	52,025
F2019	17,876	14,557	4,422	18,979	13,766	404	51,025	897	309	52,231	5,481	57,712	10.5%	57,397	52,131
F2020	18,349	14,336	4,311	18,647	13,235	399	50,630	1,049	312	51,991	5,783	57,774	11.1%	57,463	51,878
Forecast															
F2021	19,912	12,937	4,341	17,278	12,247	469	49,906	1,223	311	51,439	5,216	56,655	10.1%	56,376	51,283
F2022	20,095	13,873	4,675	18,549	12,645	507	51,795	1,127	313	53,236	5,405	58,640	10.2%	58,348	53,034
F2023	20,166	14,339	4,906	19,245	13,481	471	53,363	1,123	311	54,797	5,542	60,340	10.1%	60,027	54,621
F2024	20,515	14,410	4,914	19,324	14,399	408	54,645	1,125	311	56,082	5,628	61,709	10.0%	61,366	55,965
F2025	20,822	14,448	4,966	19,413	15,412	408	56,055	1,152	311	57,518	5,693	63,212	9.9%	62,866	57,400
F2026	21,138	14,491	5,002	19,493	16,357	408	57,396	1,146	313	58,855	5,759	64,614	9.8%	64,264	58,737
F2027	21,506	14,538	5,052	19,589	16,837	409	58,341	1,233	311	59,885	5,842	65,728	9.8%	65,375	59,767
F2028	21,930	14,598	5,107	19,705	17,277	409	59,322	1,250	311	60,883	5,920	66,803	9.7%	66,450	60,765
F2029	22,334	14,640	5,151	19,791	17,337	410	59,871	1,285	311	61,467	5,982	67,449	9.7%	67,094	61,349
F2030	22,774	14,687	5,182	19,869	17,412	410	60,466	1,312	313	62,091	6,048	68,139	9.7%	67,784	61,972
F2031	23,217	14,727	5,225	19,952	17,455	411	61,035	1,362	311	62,708	6,113	68,822	9.7%	68,466	62,589
F2032	23,705	14,775	5,263	20,038	17,554	411	61,708	1,396	311	63,416	6,188	69,603	9.8%	69,247	63,297
F2033	24,164	14,814	5,308	20,121	17,534	412	62,231	1,430	311	63,973	6,250	70,222	9.8%	69,865	63,854
F2034	24,671	14,864	5,350	20,214	17,514	412	62,811	1,467	313	64,591	6,319	70,910	9.8%	70,552	64,471
F2035	25,194	14,918	5,390	20,309	17,491	413	63,407	1,510	311	65,228	6,390	71,618	9.8%	71,259	65,108
F2036	25,762	14,985	5,434	20,419	17,463	413	64,057	1,541	311	65,909	6,467	72,376	9.8%	72,017	65,789
F2037	26,271	15,032	5,471	20,503	17,424	414	64,612	1,551	311	66,474	6,531	73,006	9.8%	72,646	66,354
F2038	26,822	15,085	5,510	20,594	17,393	414	65,223	1,562	313	67,098	6,603	73,701	9.8%	73,340	66,978
F2039	27,370	15,129	5,551	20,681	17,365	415	65,831	1,565	311	67,708	6,673	74,380	9.9%	74,018	67,587
F2040	27,946	15,195	5,598	20,794	17,335	415	66,489	1,572	311	68,373	6,749	75,121	9.9%	74,758	68,252
F2041	28,483	15,256	5,649	20,905	17,288	416	67,092	1,603	311	69,007	6,821	75,828	9.9%	75,464	68,886
Actual															
5yr Growth[4]															
F15-F20	0.4%	-0.2%	0.4%	0.0%	-1.2%	1.6%	-0.2%	1.7%	0.4%	-0.1%	5.7%	0.4%	5.9%	0.4%	-0.2%
Fcst															
5yr Growth[4]															
F20-F25	2.6%	0.2%	2.9%	0.8%	3.1%	0.4%	2.1%	1.9%	0.0%	2.0%	-0.3%	1.8%	-2.3%	1.8%	2.0%

Notes:

1 Forecast values include load additions (EVs, Codes and Standards Overlap, LCE/Fuel Switching) and large industrial DSM persistence estimates.

2 Light Industrial/Commercial is the sum of the loads in the light industrial sector and commercial sector.

3 Domestic sales equals total firm sales less sales to BC Hydro own use.

4 Growth rates are computed over a five year period on an annual compound growth basis.

Table G-2 – Temperature Normalized Actuals and December 2020 Reference Load Forecast After Rate Impact Adjustment

Total Hydro	December 2020 Load Forecast - AFTER RATE IMPACTS[1]														
	Resid-ential Sales (GWh)	Commercial Sales (GWh)	Light Industiral (GWh)	Commercial/ Light Industrial[1] (GWh)	Large Industrial Sales (GWh)	Irrig Str Lt BCH Own Use Sales (GWh)	Total BC Hydro Service Area Sales (GWh)	Sales to City of New Westminster & FortisBC Electric Sales (GWh)	Sales to Seatle City Light Hyder, Alaska Sales (GWh)	Total Firm Sales (GWh)	Total System Losses (GWh)	Total Gross System Require-ments (GWh)	Losses % of Total Sales (GWh)	Integrated Total Gross System Require-ments (GWh)	Total Domestic Sales (GWh)
Temperature Normalized Actuals															
F2015	17,973	14,460	4,227	18,687	14,055	369	51,084	966	306	52,356	4,380	56,736	8.4%	56,407	52,283
F2016	18,019	14,257	4,148	18,405	13,698	393	50,515	971	309	51,795	5,531	57,326	10.7%	56,997	51,724
F2017	17,952	14,582	4,275	18,857	13,106	381	50,296	1,053	319	51,668	5,195	56,863	10.1%	56,535	51,599
F2018	17,997	14,513	4,364	18,877	13,513	382	50,769	1,016	313	52,098	5,547	57,645	10.6%	57,316	52,025
F2019	17,876	14,557	4,422	18,979	13,766	404	51,029	897	309	52,235	5,481	57,716	10.5%	57,401	52,131
F2020	18,349	14,336	4,311	18,647	13,235	399	50,530	1,049	312	51,891	5,783	57,674	11.1%	57,363	51,878
Forecast															
F2021	19,961	12,968	4,351	17,320	12,277	469	50,027	1,224	311	51,561	5,231	56,792	10.1%	56,513	51,405
F2022	20,156	13,916	4,690	18,605	12,684	508	51,953	1,129	313	53,395	5,425	58,820	10.2%	58,526	53,193
F2023	20,203	14,365	4,915	19,280	13,505	472	53,460	1,124	311	54,895	5,559	60,454	10.1%	60,140	54,719
F2024	20,567	14,446	4,926	19,373	14,435	408	54,783	1,127	311	56,220	5,669	61,889	10.1%	61,545	56,103
F2025	20,850	14,467	4,973	19,440	15,433	408	56,132	1,153	311	57,595	5,780	63,375	10.0%	63,029	57,477
F2026	21,199	14,534	5,016	19,550	16,405	409	57,563	1,148	313	59,024	5,900	64,923	10.0%	64,573	58,906
F2027	21,569	14,580	5,066	19,647	16,887	410	58,512	1,234	311	60,058	5,992	66,049	10.0%	65,696	59,940
F2028	21,994	14,641	5,122	19,763	17,328	410	59,495	1,252	311	61,058	6,085	67,144	10.0%	66,789	60,940
F2029	22,399	14,683	5,166	19,849	17,387	411	60,046	1,286	311	61,643	6,147	67,791	10.0%	67,435	61,525
F2030	22,841	14,730	5,197	19,927	17,463	411	60,643	1,314	313	62,269	6,213	68,483	10.0%	68,127	62,150
F2031	23,285	14,770	5,240	20,010	17,506	412	61,214	1,363	311	62,888	6,279	69,168	10.0%	68,811	62,769
F2032	23,774	14,818	5,278	20,096	17,606	412	61,889	1,398	311	63,598	6,353	69,951	10.0%	69,594	63,479
F2033	24,235	14,857	5,323	20,180	17,585	413	62,413	1,432	311	64,156	6,416	70,572	10.0%	70,214	64,037
F2034	24,743	14,908	5,366	20,274	17,565	413	62,995	1,468	313	64,776	6,485	71,261	10.0%	70,903	64,656
F2035	25,268	14,962	5,406	20,368	17,542	414	63,592	1,512	311	65,415	6,556	71,971	10.0%	71,612	65,295
F2036	25,837	15,029	5,450	20,479	17,514	414	64,244	1,543	311	66,098	6,633	72,732	10.0%	72,371	65,978
F2037	26,348	15,076	5,487	20,563	17,475	415	64,801	1,553	311	66,665	6,698	73,363	10.0%	73,002	66,545
F2038	26,900	15,129	5,526	20,655	17,444	415	65,414	1,564	313	67,291	6,770	74,061	10.1%	73,698	67,171
F2039	27,451	15,174	5,568	20,741	17,416	416	66,024	1,567	311	67,902	6,840	74,742	10.1%	74,379	67,781
F2040	28,027	15,240	5,615	20,854	17,386	416	66,684	1,574	311	68,569	6,916	75,485	10.1%	75,121	68,448
F2041	28,567	15,301	5,666	20,967	17,339	417	67,289	1,605	311	69,205	6,989	76,193	10.1%	75,829	69,084
Actual 5yr Growth[4]															
F15-F20	0.4%	-0.2%	0.4%	0.0%	-1.2%	1.6%	-0.2%	1.7%	0.4%	-0.2%	5.7%	0.3%	5.9%	0.3%	-0.2%
Fcst 5yr Growth[4]															
F20-F25	2.6%	0.2%	2.9%	0.8%	3.1%	0.5%	2.1%	1.9%	0.0%	2.1%	0.0%	1.9%	-2.1%	1.9%	2.1%

Notes:

1 Forecast values include are the same as table G-1 plus rate impact adjustments.
2 Light Industrial/Commercial is the sum of the loads in the light industrial sector and commercial sector.
3 Domestic sales equals total firm sales less sales to BC Hydro own use.
4 Growth rates are computed over a five year period on an annual compound growth basis.

Table G-3 – Temperature Normalized Actuals and December 2020 Reference Load Forecast After Adjustments for Rate Impacts, DSM and VVO Savings

Total Hydro	December 2020 Load Forecast- WITH DSM AND LOSS REDUCTIONS[1]														
	Resid-ential Sales (GWh)	Commercial Sales (GWh)	Light Industrial (GWh)	Commercial Light Industrial[2] (GWh)	Large Industrial Sales (GWh)	Irrig Str Lt BCH Own Use Sales (GWh)	Total BC Hydro Service Area Sales (GWh)	Sales to City of New Westminster & FortisBC Electric Sales (GWh)	Sales to Seatle City Light Hyder, Alaska Sales (GWh)	Total Firm Sales (GWh)	Total System Losses (GWh)	Total Gross System Require-ments (GWh)	Losses % of Total Sales (GWh)	Integrated Total Gross System Require-ments (GWh)	Total Domestic[3] Sales (GWh)
Temperature Normalized Actuals															
F2015	17,973	14,460	4,227	18,687	14,055	369	51,084	966	306	52,356	4,380	56,736	8.4%	56,407	52,283
F2016	18,019	14,257	4,148	18,405	13,698	393	50,515	971	309	51,795	5,531	57,326	10.7%	56,997	51,724
F2017	17,952	14,582	4,275	18,857	13,106	381	50,296	1,053	319	51,668	5,195	56,863	10.1%	56,535	51,599
F2018	17,997	14,513	4,364	18,877	13,513	382	50,769	1,016	313	52,098	5,547	57,645	10.6%	57,316	52,025
F2019	17,876	14,557	4,422	18,979	13,766	404	51,029	897	309	52,235	5,481	57,716	10.5%	57,401	52,131
F2020	18,349	14,336	4,311	18,647	13,235	399	50,530	1,049	312	51,891	5,783	57,674	11.1%	57,363	51,878
Forecast															
F2021	19,799	12,864	4,326	17,190	12,165	469	49,624	1,224	311	51,159	5,191	56,349	10.1%	56,070	51,003
F2022	19,789	13,654	4,628	18,282	12,437	508	51,017	1,129	313	52,459	5,330	57,788	10.2%	57,496	52,257
F2023	19,678	13,968	4,825	18,794	13,183	472	52,127	1,124	311	53,562	5,422	58,984	10.1%	58,672	53,386
F2024	19,892	13,921	4,810	18,730	14,042	408	53,072	1,127	311	54,509	5,492	60,002	10.1%	59,660	54,392
F2025	20,033	13,820	4,825	18,645	14,982	408	54,068	1,153	311	55,532	5,566	61,098	10.0%	60,755	55,414
F2026	20,250	13,774	4,841	18,615	15,896	409	55,170	1,148	313	56,630	5,651	62,282	10.0%	61,934	56,512
F2027	20,494	13,723	4,867	18,590	16,335	410	55,828	1,234	311	57,373	5,713	63,086	10.0%	62,720	57,255
F2028	20,809	13,698	4,896	18,594	16,741	410	56,554	1,252	311	58,117	5,779	63,896	9.9%	63,529	57,999
F2029	21,112	13,655	4,913	18,568	16,745	411	56,836	1,286	311	58,434	5,813	64,246	9.9%	63,879	58,316
F2030	21,458	13,627	4,917	18,544	16,757	411	57,171	1,314	313	58,797	5,852	64,649	10.0%	64,281	58,678
F2031	21,812	13,598	4,935	18,533	16,754	412	57,511	1,363	311	59,185	5,894	65,079	10.0%	64,711	59,066
F2032	22,215	13,580	4,952	18,532	16,828	412	57,987	1,398	311	59,696	5,947	65,642	10.0%	65,275	59,577
F2033	22,593	13,556	4,977	18,533	16,791	413	58,330	1,432	311	60,073	5,989	66,062	10.0%	65,695	59,954
F2034	23,019	13,544	5,006	18,551	16,759	413	58,742	1,468	313	60,523	6,040	66,563	10.0%	66,196	60,403
F2035	23,460	13,537	5,037	18,573	16,727	414	59,174	1,512	311	60,997	6,093	67,090	10.0%	66,722	60,877
F2036	23,948	13,543	5,071	18,613	16,690	414	59,666	1,543	311	61,520	6,152	67,672	10.0%	67,305	61,400
F2037	24,379	13,536	5,101	18,637	16,645	415	60,075	1,553	311	61,939	6,201	68,140	10.0%	67,772	61,819
F2038	24,852	13,543	5,134	18,677	16,608	415	60,553	1,564	313	62,430	6,257	68,687	10.0%	68,320	62,310
F2039	25,328	13,543	5,172	18,715	16,577	416	61,036	1,567	311	62,914	6,313	69,227	10.0%	68,859	62,793
F2040	25,833	13,558	5,215	18,773	16,543	416	61,565	1,574	311	63,450	6,375	69,824	10.0%	69,455	63,329
F2041	26,360	13,605	5,279	18,884	16,575	417	62,235	1,605	311	64,151	6,451	70,603	10.1%	70,232	64,030
Actual 5yr Growth[5]															
F15-F20	0.4%	-0.2%	0.4%	0.0%	-1.2%	1.6%	-0.2%	1.7%	0.4%	-0.2%	5.7%	0.3%	5.9%	0.3%	-0.2%
Fcst 5yr Growth[5]															
F20-F25	1.8%	-0.7%	2.3%	0.0%	2.5%	0.5%	1.4%	1.9%	0.0%	1.4%	-0.8%	1.2%	-2.1%	1.2%	1.3%

Notes:

1 Forecast values are the same as table G-2 minus adjustments for DSM savings and VVO savings.
2 Light Industrial/Commercial is the sum of the loads in the light industrial sector and commercial sector.
3 Domestic sales equals total firm sales less sales to BC Hydro own use.
4 Growth rates are computed over a five year period on an annual compound growth basis.

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix G

Vegetation Management Strategy (VMS)

Table of Contents

List of Figures

List of Tables

1 # 1 Definitions of Key Terms

2 There are a number of vegetation management-related trade terms used in this
3 document, which are set out below for ease of reference.

Term	Description / Definition
Edge Tree	Refers to a tree at the edge of the right-of-way that was identified as a potential risk as a result of its condition or other observable factors. Edge trees are removed to reduce the risk of them falling onto transmission assets.
Distribution Vegetation Management	Managing the vegetation on the distribution system. The vast majority of vegetation is on private or public land in proximity to the power system.
Hot-Spotting	Selective and targeted removal of a tall tree(s) or area within the transmission system to address an immediate risk or area of concern.
Hazard Tree	A tree that has a defect or adverse environmental condition that predisposes it to failure and that can cause damage if it falls (e.g., a power line, electrical equipment, buildings, people, etc.).
Light Detection and Ranging (**LiDAR**)	A LiDAR sensor uses infrared and ultraviolet light to map out the environment around it. It can get a sense of both the physical dimensions and motion (if any) of objects in its vicinity.
Rights-of-Way (**ROW**)	The legal right to the area below and surrounding transmission lines where BC Hydro is responsible for vegetation management and maintenance.
Riparian	The area of land adjacent to a water body that contains vegetation that is distinctly different from the vegetation of adjacent upland areas due to the presence of water.
Right-of-Way Clearing	Full clearing of vegetation within the right-of-way beneath and adjacent to the transmission system.
Transmission Vegetation Management	Managing the vegetation in proximity to high voltage transmission lines, including directly underneath and adjacent to conductors and structures.
Vegetation Management	The practice of reducing the risk of contact between vegetation (e.g., trees, shrubs, etc.) and electrical assets by proactively removing vegetation or reducing it in size or height.
VegNET	A mobile field application used to facilitate and spatially locate all tasks and activities related to transmission vegetation and access for BC Hydro staff, consultants and contractors.
On-Cycle Distribution Vegetation Management Work	Vegetation maintenance activities performed according to the standard work plan that aligns to vegetation growth rates and regional needs. Results in efficient area-based management and addresses vegetation risks in the area specified within the work plan.

Term	Description / Definition
Off-Cycle Distribution Vegetation Management Work	Off-cycle work often involves triage of required vegetation needs and highest risk areas receiving treatment versus full area maintenance. It results from a deviation from the optimal work plan in response to unplanned impacts. Average cost of off-cycle work is higher than on-cycle work.
Vegetation Accumulation	Vegetation growth on the system that has not been addressed within the current work plan and requires attention. Vegetation in this state constitutes an accumulation of vegetation material and work effort is necessary for removal.
High Voltage Transmission Circuits (**HVTC**)	Vegetation management description of transmission lines above 138 kV (but includes the 138 kV interties to Alberta) that are subject to the FAC-003 mandatory reliability standard due to system criticality.
Low Voltage Transmission Circuits (**LVTC**)	Vegetation management description of transmission lines at or below 138 kV.
Canadian Electricity Association (**CEA**)	The Canadian Electricity Association is national in scope and includes representation from all major Canadian utilities.
Program and Contract Management (**PCM**)	The Program and Contract Management KBU is responsible for the execution of capital and maintenance work programs on the generation, transmission and distribution systems as well as smaller scale projects on the BC Hydro system including distribution system improvement, major customer, substation and generation facility upgrades.
Site Prescription	A specific set of professional instructions developed by experienced foresters, biologists or other qualified vegetation personnel pertaining to the treatment plan for a specific site.

2 Version History and Revision Control

Version	Date / Version Notes
Version 1.0	July 12, 2021

Directive 10 of the BCUC's Decision on the Previous Application directed BC Hydro to file the new Vegetation Management Strategy and any revisions to it thereafter. The following defines the changes that would constitute a revision to the Vegetation Management Strategy:

Change	Description / Definition
Program Expenditures and Resource Variance	Annual vegetation expenditures and resources (FTEs) > 5 per cent.
Core Program Change(s)	Planned annual work volumes that are reduced below the minimum levels identified within the VMS.
Compliance Impacting Program Adjustments	Any deliberate program adjustment that would impact the ability to achieve mandatory compliance requirements.

The following occurrences do not constitute a revision to the Vegetation Management Strategy:

Event	Description / Definition
Uncontrollable Work Output Impacts	Variances to actual work outputs based on circumstances that are uncontrollable (e.g., work stoppage during drought, wildfires, labour disruption, etc.).
Non-Core Initiative(s) Scope, Schedule and Delivery	Beyond the core vegetation maintenance program, the VMS articulates a series of initiatives and pursuits. The scope, schedule and delivery of these will be adjusted regularly based on the requirements of the core maintenance program and would not constitute a revision of the VMS.
Continuous Improvements and Internal Organizational Structures	Over the course of the VMS delivery, it is expected that processes will be reviewed and enhanced, these would not require a formal revision of the strategy. Internal organization structures and accountabilities may also evolve over time and will not trigger a formal revision providing the impact to work output is not materially detrimental.

BC Hydro will file any revisions to the Vegetation Management Strategy with the BCUC.

3 Executive Summary

BC Hydro has an ongoing need to maintain vegetation surrounding the electrical system to ensure safe and reliable delivery of electricity. Vegetation management is a significant undertaking in British Columbia due to the size of the electrical system (approximately 18,500 kms of overhead transmission lines, over 48,600 kms of overhead distribution lines), the design of the system (primarily overhead), the climate (significant precipitation) and the extent of forestation (including fast growing and tall flora species).

Following an analysis in fiscal 2021 and summarized in the Fiscal 2022 Revenue Requirements Application, BC Hydro identified the need for incremental investment in vegetation management as a result of numerous exogenous cost pressures absorbed over the past decade while the program annual budget remained relatively stable. System performance was maintained by a prior period of extensive clearing and the benefits of this activity have been realized as the cost pressures were absorbed in the program. As a result of the recent vegetation accumulation adjacent to the electrical system, there is now a need to increase the overall annual vegetation program to sustain a regular maintenance cycle that is equal to regrowth levels.

BC Hydro has developed a new Vegetation Management Strategy (**VMS**) that defines the annual program that achieves a stable annual maintenance cycle while improving the capability to proactively identify emerging areas of need. Additionally, the strategy identifies a series of initiatives, pursuits and studies that will continue to enhance the overall ability for BC Hydro to deliver vegetation work and reduce the risk posed by vegetation (including encroachments, wildfires and similar hazards).

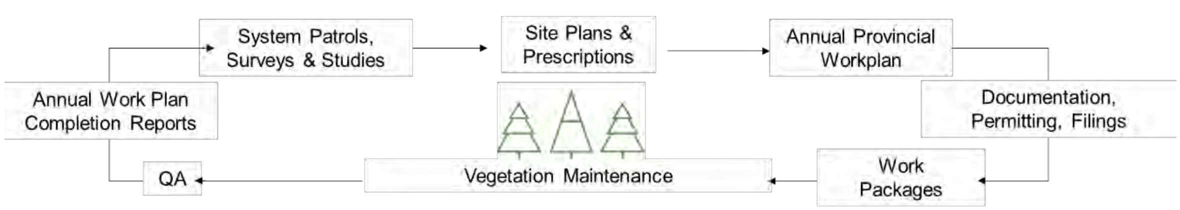
The annual expenditure for vegetation management will increase from the prior decade average of approximately $50 million per year to a new normal of approximately $90 million per year. The incremental investment is believed to be sufficient to identify and meet the required needs of the system including: maintaining compliance, improving reliability and achieving the stated goals of the new VMS under normal conditions. Following this increase, BC Hydro still continues to remain among the lowest cost utilities with respect to vegetation management expenditures on a per customer basis while delivering a vegetation program that meets industry standards and compliance requirements.

4 Background

BC Hydro's significant annual investment in vegetation management reflects the importance of this area to the safe and reliable operation of the BC Hydro system and the Western Bulk Electric System. Vegetation management is a core utility function for overhead power systems (both transmission and distribution), access areas (roads, helipads, bridges, etc.), stations and properties. Growing vegetation poses an ongoing risk to electrical assets in addition to representing an immediate safety hazard in instances of contact between vegetation and live conductors. Unmanaged vegetation can grow too close or into the power system, fall onto assets, bring overhead conductors to ground level or act as a source for fire ignition. A vegetation management program is essential to maintain adequate clearances between vegetation and electrical assets in addition to removing risks adjacent to the system.

Figure G-1 below outlines the high-level annual vegetation work cycle from planning to delivery.

Figure G-1 Annual High-Level Vegetation Work Cycle

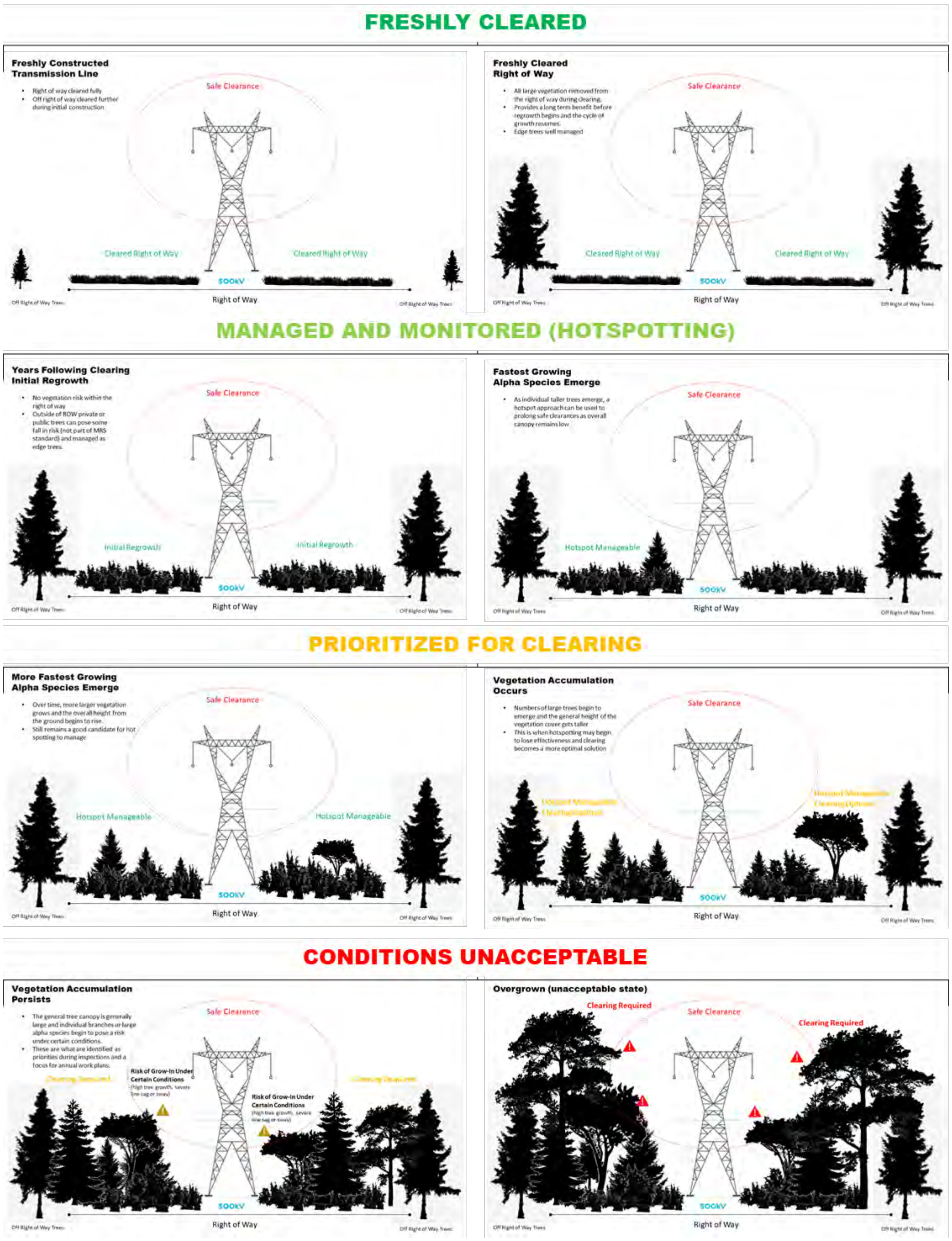


4.1 Background - Transmission System

For the transmission system, vegetation management involves three core practices: full clearing, hotspotting and edge tree management. **Full clearing** is when an area of a right-of-way (**ROW**) is cleared to the ground through various vegetation management techniques (e.g., mowing, brushing, falling, etc.). **Hotspotting** is when selective stands of trees or individual large trees are removed while the surrounding area is left untreated. This is used when only a small number of faster and larger species begin to emerge within an area that does not yet need full clearing to maintain clearances between conductors and the base vegetation canopy. **Edge tree removal** involves removing hazard trees at the edge of the ROW that pose a risk of falling into the ROW and onto a power system asset. The combination of these approaches preserves the clearances for the transmission system to safely operate as designed.

Figure G-2 below illustrates the various vegetation states around the transmission system in addition to the types of scenarios that maintenance approaches are used (e.g., clearing versus hotspotting). The figure also illustrates unacceptable states where growth is in excess of regular planned cycle work, inconsistent with planning standards and will be avoided through the defined execution levels within the VMS.

Figure G-2 Transmission Vegetation States Explained



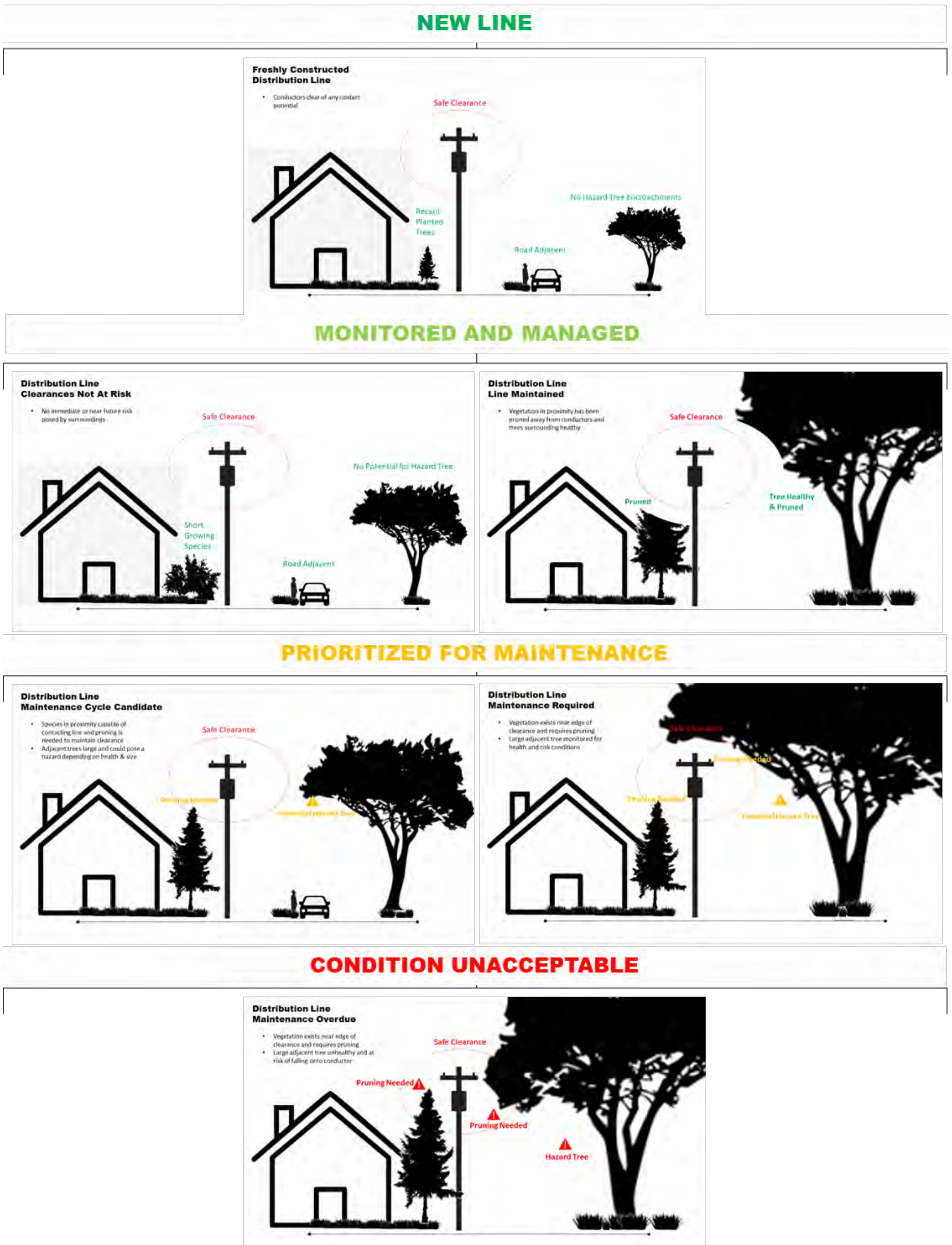
4.2 Background – Distribution System

For the distribution system, vegetation management involves two core practices; pruning and hazard tree removal. **Pruning** is the practice of cutting vegetation adjacent to the distribution system back and away from the conductors. Pruning also involves clearing of vegetation (by mowing, brushing, etc.) below the distribution lines that have the potential to grow up and into the lines over time. **Hazard tree removal** targets trees that pose a potential risk to the electrical system and often involve large specimens that are dead, dying or showing signs of instability. Although perfectly healthy trees can contact a line during a storm event, hazard trees represent a general risk outside of adverse weather conditions due to their general state.

Distribution vegetation management also involves working closely with landowners, municipalities and government to ensure appropriate selections of vegetation species near power lines. For example, when a homeowner plants a sapling in their yard under a power line, they may be unaware that it will grow up and into the line in future years, representing a reliability and safety risk. When identified, BC Hydro will work with them to ideally replace the tree with something that would not pose a future risk or prune the tree in such a way where future growth is mitigated below or around the conductors.

In Figure G-3 below, the various high-level states of distribution vegetation are illustrated in addition to the types of approaches for maintaining them. The illustration also shows unacceptable states that are avoided through the delivery of the regular work plan within the new VMS.

1 **Figure G-3 Distribution Vegetation States Explained**



5 Why a New Vegetation Management Strategy?

Three primary factors are contributing to the need for a significant increase in vegetation management investment, that in turn prompted the need for a new VMS, each of which was described in Fiscal 2022 Revenue Requirements Application and is restated below:

1. Vegetation growth across the system has regrown back to levels that existed prior to the significant clearing activities that took place a decade ago;
2. Cost pressures have increased with electrical system expansion, new regulatory requirements and general cost inflation associated with vegetation maintenance activities, and can no longer be absorbed; and
3. Climate change is impacting the growth rate and health of vegetation across the province.

Significant vegetation activities occurred a decade ago and created lasting benefits in the years following. This is reflected in Figure G-4 and Figure G-5 below, which shows that investment in vegetation management increased between fiscal 2002 and fiscal 2009 for transmission and until fiscal 2014 for distribution, before remaining largely static (in terms of real dollars) at a lower level until fiscal 2022. During this period and until fiscal 2020, system reliability and compliance was maintained annually. Regrowth of vegetation has occurred system wide to the extent that the benefits from the heightened vegetation maintenance period have been exhausted and additional effort is now required to sustain or improve system performance.

Figure G-4 Transmission Vegetation Maintenance Levels

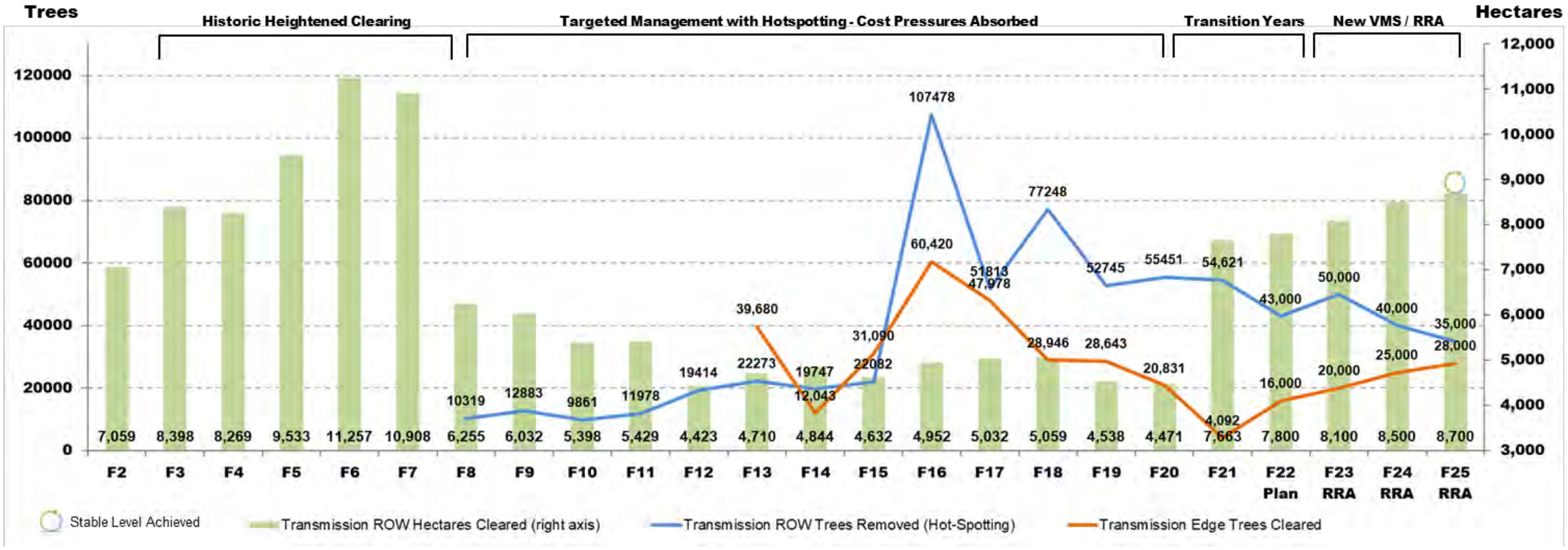
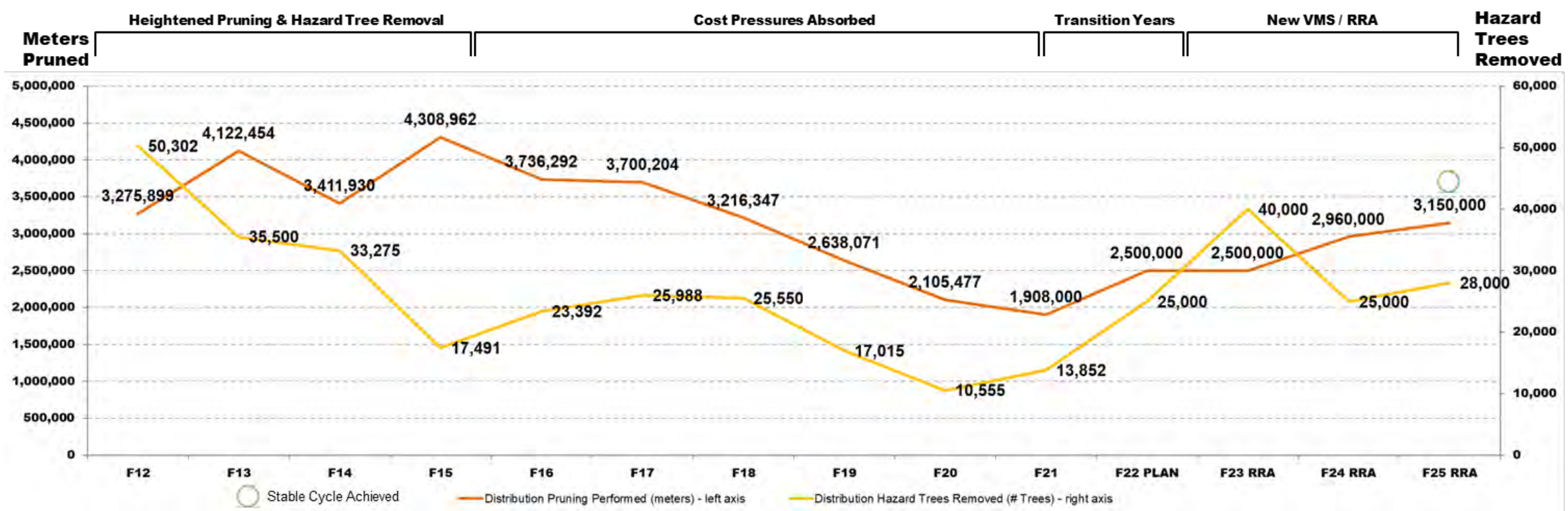


Figure G-5 Distribution Vegetation Maintenance Levels



The direct impact of the vegetation regrowth and accumulation was minimized by other investments made by BC Hydro during this time (e.g., distribution automation, smart metering infrastructure). These investments contributed to key corporate outcomes, such as reliability performance metrics. A combination of reduced vegetation maintenance and these asset investments collectively preserved system reliability and safety in the latter years when vegetation regrowth had begun to accumulate on the system. This was evidenced by increased trouble costs as a result of vegetation originated system impacts. During fiscal 2020 and fiscal 2021, BC Hydro analyzed the increasing impact of vegetation regrowth and determined that the base level of vegetation effort now must increase in order to sustain the long-term objectives of the vegetation maintenance program and corporate reliability targets.

6 Determining the Right Approach for the VMS

BC Hydro analyzed four different potential approaches to shape the future vegetation management, listed and explained below. BC Hydro's analysis determined that the second approach – stable annual vegetation maintenance – was the best approach.

1. **Status Quo Preserved** (continue at the fiscal 2021 level of investment).
2. **Stable Annual Vegetation Maintenance** (stable year over year, size of program matches vegetation growth rate over a regular cycle).
3. **Cyclical** (cycles of heightened vegetation activity followed by reduced durations of low activity).
4. **Hotspotting / Triage Only** (focuses on removing vegetation two growing seasons before it is expected to become a challenge, dynamically targeted annually).

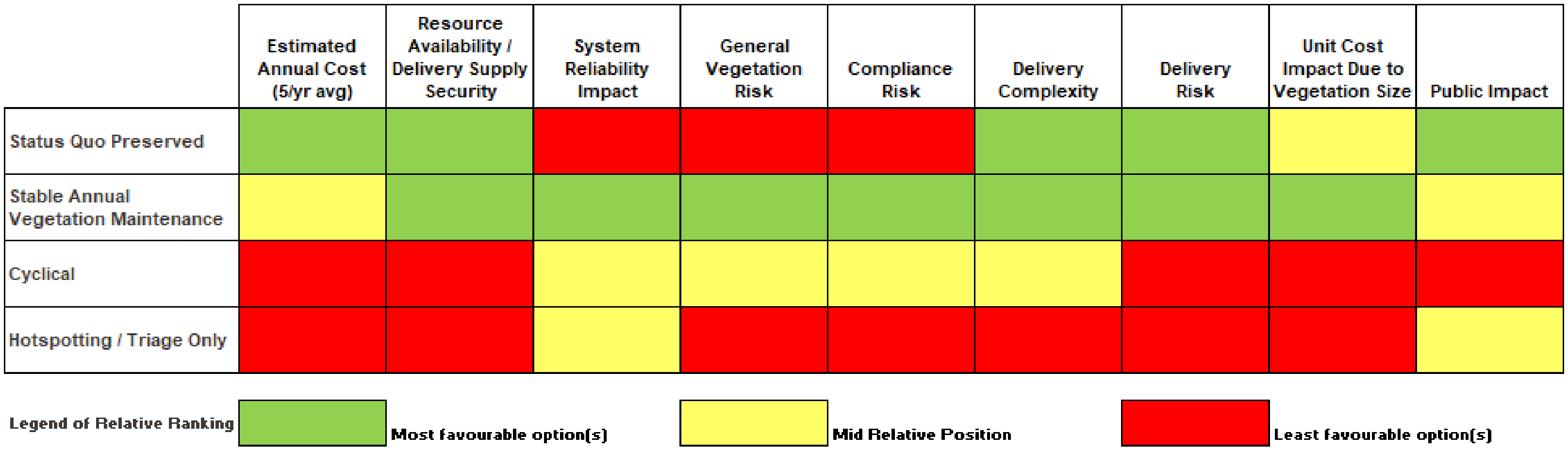
During this analysis, core criteria of the vegetation program were considered in addition to delivery factors (such as resource availability, cost of delivery, etc.). Each criterion has an individual preferred outcome, and all are balanced collectively to represent the single best option. The following were the criteria analyzed to support a decision on the overall strategic approach of the vegetation program.

- **Estimated annual cost (next five-year average)** – this examined the total cost to deliver the vegetation management program averaged over the next five-year period. A five-year average was selected to smooth cost variations annually across scenarios. A lower average cost is preferable within the analysis.
- **Resource Availability / Delivery Supply Security** – this examined the extent that BC Hydro would be able to ensure sufficient resources (both internal and external) to deliver on the vegetation program. Scenarios that had high resource variability translated into risk since acquiring resources, releasing them and then reacquiring in the future represents uncertainty for supply. Stable resourcing is preferred in the analysis since it allows long term supply security.
- **System Reliability Impact** – this examined the overall impact to reliability posed by vegetation with individual approach factors considered. Regularly treated vegetation is preferred due to lower impact than leaving vegetation untreated for any prolonged period of time (allowing it time to grow).
- **General Vegetation Risk** – this examined the other risk factors outside of reliability, such as safety and asset access. Leaving vegetation unmanaged for a period of time is viewed as higher risk due to regrowth and total size of vegetation (e.g., trunk and branch diameters). Large diameter vegetation is capable of obscuring access to assets and sufficient in size to bring a live conductor to the ground.

- **Compliance Risk** – this examined the extent that BC Hydro can sustain compliance with the required standards and legislated directives. Regular assurance for compliance is preferred within the analysis versus compliance based on just in time work.
- **Delivery Complexity** – this examined the complexity of the operation necessary to deliver on the annual work program. Regular, repeatable cycles are favoured over complicated delivery regimes that involve targeted work (hotspotting and triage).
- **Delivery Risk** – this examined the overall risk in delivering on the annual work plan each year. Delivery risk introduces regionalization of work effort and consistency in the types of work delivered. Low movement of resources and standardized delivery practices are preferred.
- **Unit Cost Impact Due to Vegetation Size** – this examined the cost per unit of work delivery, which is based on vegetation size. The larger the vegetation, the more expensive it is to remove due to the tools and procedures required. The same is true for pruning where smaller branches are easier and faster to remove than large ones. Low unit cost is preferred in the analysis.
- **Public Impact** – this examines the extent each approach has the potential to impact the public (aside from reliability and safety impacts that are covered in other criteria). More regular, small pruning of vegetation within a community has a lower public impact than large cuts after extended period of untreated growth. Lower public impact is preferred within the analysis.

To support a decision, the criteria were assigned a relative position to one another, ranging from most to least preferred. Figure G-6 below shows the relative ranking of each alternative approach for all of the criteria listed above. The analysis concluded that the most viable long-term approach for vegetation management would be to evolve the current program into a long-term stable model where a general cycle is established to address growth as it occurs. The new VMS was developed around this option where annual work volumes are directly related to the vegetation surrounding the transmission and distribution systems with additional considerations for access roads, properties and stations. Although the status quo was the lowest cost option, it is not capable of sustaining ongoing compliance due to regrowth and represents greater system impacts (namely reliability and safety) than deemed acceptable.

Figure G-6 Vegetation Approach Analysis Summary



7 Stable Annual Vegetation Maintenance – Goals and Objectives

Once BC Hydro decided on the stable annual vegetation maintenance approach, the remainder of the VMS was developed around this approach. This section will outline the goals and objectives of this approach. **Goals** are defined as the resulting outcomes sought by the VMS realized through the delivery of the vegetation management program, whereas the **objectives** are more focused on the specific actions that will be taken as part of the VMS to achieve the goals. Many of the goals in the new strategy are aligned with the vegetation management program goals in the past (e.g., safety, reliability, compliance, etc.). The VMS has further defined the extent of work required to meet the goals and added related areas of focus (e.g., access).

The primary goals of the new VMS are as follows:

Safety: Manage the ongoing and persistent risks posed from growing vegetation to the electric system to support both employee and public safety, with an additional focus on fire ignition prevention and mitigation.

Reliability: Ensure appropriate system reliability through the reduction of vegetation related contacts with utility assets.

Compliance: Manage ongoing compliance with all regulatory, statutory and legal requirements.

Access: Secure appropriate and safe access to assets and rights-of-way.

Stewardship: Act as responsible stewards of vast areas of vegetation within rights-of-way and across public and private property and continue to ensure social, environmental, financial and cultural perspectives are respected while balanced with vegetation management needs of the electrical system.

All of the above stated goals align with the core mandate of BC Hydro of providing safe, reliable and affordable electricity to the province of British Columbia. It is recognized by BC Hydro that vegetation management is an important maintenance program. The program is annually delivered provincially and has a direct relationship with reliability, safety and compliance when the necessary clearances between vegetation and the electrical system are maintained. Assuring vegetation is well managed and away from the electrical system reduces risks of system damage, fire ignition and other hazards. Another key tenet of vegetation management effort is ensuring unimpeded access to electrical and communications assets. Access is necessary to maintain and operate these assets safely for the duration of their operable life.

Furthermore, through the delivery of the vegetation management efforts, BC Hydro demonstrates appropriate stewardship of its maintenance duties to ensure social, environmental, financial and cultural perspectives are respected. These responsibilities are realized through ongoing consultation and cooperation with those who have a stake in the vegetation work being conducted across the province and the prudent management of all resources.

To meet the goals outlined above, the VMS includes a series of actionable objectives that translate the goals into business outcomes. The actionable objectives are as follows:

- Plan and implement an effective vegetation management program across the province that ensures sustainable mitigation of the risk posed by regular annual growth, notable events (infestations, droughts, climate impacts, etc.) and storms;

- Improve visibility of vegetation across the system and adopt a more dynamic approach of assessing annual workplans that take into account variable growth rates, system conditions and climate impacts;
- Strengthen compliance assurance within vegetation program delivery and processes;
- Manage climate change impacts and risks (e.g., wildfires, storm resiliency, tree health from drought, flooding, disease and other impacts);
- Secure vegetation management resources and ensure supply;
- Maximize efficacy of vegetation investment (e.g., treatment longevity, vegetation and access inspections combined, etc.); and
- Optimize vegetation management delivery.

Through the successful implementation of the VMS, the following business outcomes will be achieved.

Figure G-7 VMS Business Outcomes by Goal

The new Vegetation Management Strategy will deliver the following business outcomes:					
Removal of all vegetation accumulation on the system					
• Transmission accumulation removed between F25 and F27 (based on F22-F24 work outputs)	●	●	●	●	●
• Distribution hazard tree inventory addressed by end of F23	●	●	●	●	●
• Distribution pruning work secured on-cycle by F25	●	●	●	●	●
Improved system visibility					
• Enhanced patrol, survey and LiDAR capabilities – no surprises and imbedded quality assurance	●	●	●	●	●
• Improved metrics and reporting for proactive identification of issues	●	●	●	●	●
Compliance assurance					
• Improved compliance integration within work planning and delivery	●	●	●		
• Compliance delivery visibility in near real time (e.g. FastVeg reports, system imaging, etc.)	●	●	●		
Risk Reduction					
• Climate change and fire reduction activities	●	●	●	●	●
• Access assurance, inspections and clearing	●	●	●	●	●
• Secured resources to perform necessary work	●	●	●	●	●
Delivery Value					
• Improved cost stability through category management approach and contracts					●
• Internal optimization of resources					●
• Improved processes					●

8 BC Hydro’s Vegetation Program Fiscal 2023 to Fiscal 2025

Under the stable annual vegetation maintenance approach, BC Hydro’s vegetation management effort is expected to increase during the next three years and then remain stable by fiscal 2025, representing the new normal for vegetation activities. This is represented as the work output required to achieve the goals of the vegetation maintenance program, reflected as a range between minimum and optimal levels. Table G-1 below shows the minimum and optimal annual work levels for each activity by fiscal 2025. The minimum level represents the smallest work effort that would not result in incremental accumulation of vegetation on or around the electrical system and achieve mandatory compliance requirements only. The minimum level is vulnerable to unplanned events (e.g., work stoppages due to dry spells, external resource availability, wildfires, etc.), climate change impacts and work disruptions. To address these, the optimal level was developed and represents the amount of regular work that would both ensure achievement of the VMS goals while offering a degree of resilience to uncontrollable events.

Table G-1 Minimum and Optimal Work Levels

Category	Activity	Minimum Annual Work Level	Optimal Annual Work Level
Transmission Vegetation Maintenance	ROW Clearing (hectares)	**6,700**	**8,600** (adjusted to achieve VMS goals and address climate change uncertainty)
	Hotspotted Trees Removed (trees)	**40,000**	**30,000** (only optimal w hen clearing at optimal level)
	Edge Trees Removed (trees)	**25,000**	**30,000**
	LiDAR Scanned and Modelled (% of system)	**20%**	**20%**
	System Patrolled & Inspected (% of system)	**100%**	**100%**
Distribution Vegetation Maintenance	Vegetation Pruned (meters)	**3,100,000**	**3,300,000**
	Hazard Trees Removed (trees)	**26,000**	**30,000**
	System Patrolled & Inspected (% of system)	**33%**	**50%**
Access, Facilities and Properties	Access Patrolled & Inspected (% of system)	**33%**	**50%**
	Facilities Vegetation Assessment	**100%**	**100%**
	Priority Sites Maintained Post Assessment	**100% High Priority 50% Medium Priority**	**100% High and Medium**

To establish confidence that the volume of work being undertaken is consistent with industry practices and sufficient to meet the goals of the VMS, BC Hydro undertook an internal analysis and accessed a number of external sources. These are referenced and explained in the subsequent section of the strategy focused on investment justification.

To deliver this level of work to meet the needs of the system and achieve the goals of the program, the following are the planned expenditures with historical values for context. Table G-2 below shows the current and future cost estimates for delivery of the VMS.

The values used in Table G-2 are based on the established market rates for external work delivery and include foreseen cost pressures (e.g., inflation). Future cost pressures beyond fiscal 2025 (e.g., future inflation, standard labour rates, market price fluctuations, legislative requirement changes and other external influences) will need to be addressed in the future to maintain the level of work output necessary to achieve the stated goals of the program.

Table G-2 Historic and Planned Vegetation Management Costs[1, 2]

($ million)	F2012 Actual	F2013 Actual	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Actual	F2021 Actual	F2022 Decision	F2023 Plan	F2024 Plan	F2025 Plan
Transmission Vegetation Maintenance	19.8	21.6	19.9	21.7	18.4	18.9	19.0	18.7	21.5	27.1	33.3	38.9	40.0	41.9
Distribution Vegetation Maintenance	35.5	34.8	30.1	32.2	32.7	32.4	31.2	31.8	28.4	31.9	36.1	40.1	43.3	46.9
Access Maintenance	1.0	1.2	1.1	1.3	1.0	1.0	1.0	1.2	1.0	0.9	1.0	3.7	3.9	3.9
Total Gross	**56.3**	**57.6**	**51.1**	**55.2**	**52.1**	**52.4**	**51.2**	**51.7**	**50.9**	**59.9**	**70.5**	**82.7**	**87.2**	**92.8**
Distribution Vegetation Recoveries (TELUS)	(10.3)	(8.2)	(7.0)	(5.5)	(6.2)	(6.7)	(6.5)	(6.4)	(5.5)	(6.4)	(6.9)	(7.2)	(7.7)	(8.5)
Total Net of Recoveries	**46.0**	**49.5**	**44.2**	**49.7**	**45.9**	**45.7**	**44.7**	**45.3**	**45.3**	**53.5**	**63.5**	**75.5**	**79.5**	**84.3**

Over the last decade, BC Hydro has maintained a relatively consistent annual expenditure for vegetation management effort, totalling approximately $50 million per year. This increased at the end of fiscal 2021 to address imminent vegetation risks on the transmission system and in fiscal 2022, as described in the Fiscal 2022 Revenue Requirements Application. The proposed fiscal 2023 to 2025 plan amounts are subject to BCUC approval in the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application.

9 Vegetation Expenditure Justification

In support of the development of the new VMS, BC Hydro accessed and analyzed industry resources and benchmarks, and sought external validation of our approach. BC Hydro accessed the following sources to establish context for the VMS:

- Industry benchmarks from First Quartile Benchmarking;

1 F2012 to F2020 actuals are in real dollars and were adjusted using the B.C. Consumer Price Index with fiscal 2021 as the base year.

2 In the Fiscal 2022 Revenue Requirements Application, LiDAR was considered a planning operational cost as it was newly added to the vegetation management program. It has since been classified as Transmission maintenance, similar to all inspection expenditures, with the change having no impact on the overall O&M budget.

- Canadian utility vegetation study conducted by the Canadian Electricity Association (**CEA**);
- External review of BC Hydro's vegetation strategy by Guidehouse;
- Market procurement in BC for vegetation services;
- Publicly accessible utility regulatory filings from peers; and
- Internal analysis of current and historical vegetation performance and expenditures.

9.1 First Quartile Benchmarking

First Quartile Benchmarking is a utility industry resource for comparative analysis of operational areas, including vegetation management. Each year, approximately 40 utilities across North America and a small number of international utilities participate in the survey. The responses are anonymized and shared to show each participant their relative position in the industry and the quartile compared to others. Although each utility is different and varies in terms of geography, climate, vegetation species, system topography and customer composition, the large number of utility participants and normalizing factors built into First Quartile survey responses help ensure viable insight from the studies and relative comparisons. For vegetation management, factors are included in the survey related to financial expenditure, reliability and overall performance. Specific questions, such as the cost per customer to perform vegetation management work annually on the distribution system, help provide insight into overall levels of vegetation investment and delivery value. Other examples, such as reliability comparisons, provide a view into the overall outcome of vegetation management efforts. Overall, First Quartile Benchmarking was used by BC Hydro as a resource to establish a relative industry view and support context for decision making within the new VMS.

9.2 CEA 2021 Vegetation Management Benchmarking Report

Another input into the VMS was the recent 2021 Vegetation Management Benchmarking Report issued by the CEA. The CEA report provided valuable insight into specific vegetation management practices and common trends for utilities across Canada. The report covered key operational domains, including equipment usage, cycle durations, resourcing approaches and compliance categories. There also was a focus on inspection approaches where LiDAR was used by utilities of similar size to BC Hydro. The participating utilities in the CEA report included:

Table G-3 2021 CEA Vegetation Report Participants

CEA 2021 Vegetation Management Benchmarking Report Participants			
BC Hydro	Hydro Ottawa	Manitoba Hydro	FortisAlberta
Hydro Quebec	Yukon Energy	Maritime Electric	London Hydro
SaskPower	Toronto Hydro	Newfoundland Power	ENMAX
City of Medicine Hat	City of Summerside	Oakville Hydro	City of Lethbridge
ATCO	City of Red Deer	AltaLink	FortisBC
Hydro One	NB Power	NSPI	

9.3 External Review of BC Hydro's Vegetation Management Strategy by Guidehouse

BC Hydro also engaged a third-party to review the VMS and provide an independent review of the proposed program. BC Hydro selected Guidehouse to perform the review based on their demonstrable experience in utility strategy reviews and expertise in vegetation management strategy specifically. Guidehouse's approach was to review the current and proposed vegetation management strategies, interview key staff members (program managers, planners and operations), conduct a peer review and assess any notable differences between BC Hydro and other utilities. They examined specific areas within the vegetation program related to compliance requirements, cycle times, staffing, technology, clearances and overall objectives. Guidehouse also conducted a historical cost justification analysis to compare proposed expenditures to the cumulative impacts of cost pressures on the

BC Hydro vegetation program over the past decade. The study findings were detailed in a report to BC Hydro and used to inform the VMS.

9.4 Market Procurement in B.C. for Vegetation Services

Recent market procurements for vegetation services provided additional context for the VMS. The procurements established long-term, unit-based contracts that were competitively bid by external third parties. These provided assurance on the alignment of current delivery costs to market rates and ensured the necessary supply security of vegetation resources to deliver on the VMS. It also enabled accurate forecasting of unit costs over the upcoming years.

9.5 Publicly Accessible Utility Regulatory Filings from Peers

Beyond the explicit pursuits BC Hydro undertook to provide context and comparisons for the VMS, additional referenced materials included the regulatory filings of a number of utilities in Canada and the U.S. where vegetation programs were described. These were also used to ensure alignment of BC Hydro’s VMS to general industry practices.

9.6 Internal Analysis of Current and Historical Vegetation Performance and Expenditures

In 2021, BC Hydro conducted an internal analysis to review historical vegetation work activities, expenditures and cost pressures. This analysis was used to initially inform the Fiscal 2022 Revenue Requirements Application and subsequently updated to develop the VMS. The analysis also utilized the information and insight generated by the other sources mentioned in the section above. Based on the information obtained through this analysis, the following table shows the key findings supported by the referenced sources.

1 **Table G-4 Expenditure Justification Summary and**
2 **Key Findings**

Key Finding	Source(s)	Interpretation
BC Hydro's vegetation management efforts were subject to a number of exogenous cost pressures, many legislative in nature, that were also faced by the vegetation management industry in general. These include: *Mandatory Reliability Standards, Wildfire Act, Integrated Pest Management Act*, *Fisheries Act*, *Water Act*, *Migratory Bird Convention Act*, *Heritage Act*, *WSBC Requirements, Transportation Act*, *Industrial Roads Act*, *Motor Vehicle Act* and various municipal policies	BC Hydro internal analysis, Guidehouse	Exogenous cost pressures increased the unit delivery cost of BC Hydro's vegetation management program. Without incremental expenditures, total work output cannot increase
While the historical annual budget remained largely constant, increasing costs resulted in less work being completed	BC Hydro internal analysis	Reduced work volumes of vegetation management had resulted in incremental accumulation of vegetation on the system annually
BC Hydro's distribution vegetation expenditure over the last decade has been well below industry average and among the lowest in North America	First Quartile Benchmarking	Incremental distribution expenditures proposed in the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application remain consistent with lowest quartile for utilities and are reasonable
BC Hydro's transmission vegetation expenditure over the last decade have been well below industry average	First Quartile Benchmarking	Incremental transmission expenditures proposed in the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application remain consistent with industry averages and are reasonable
The current proposed expenditure is consistent with the magnitude of the historical cost pressures	Guidehouse	Each individual cost pressure, if funded when introduced historically, would have resulted in cost increases equal to or in excess of the current proposed expenditure on aggregate
BC Hydro's vegetation management activities and approach are consistent with industry practices	Guidehouse, 2021 CEA Vegetation Report	There are no anomalies in BC Hydro's vegetation approach that are driving incremental costs or representing an efficiency opportunity

Key Finding	Source(s)	Interpretation
BC Hydro would further benefit from incremental visibility to the state of vegetation on the system	Guidehouse, Canadian Electrical Association, NERC	BC Hydro will invest in improving inspections both manually and through LiDAR
BC Hydro's current contracts are consistent with market rates	BC Hydro market tenders	BC Hydro has validated market costs through a competitive process for delivery of external services
BC Hydro has fully realized the benefits derived from increased clearing that occurred a decade ago	BC Hydro vegetation analysis	Incremental vegetation management work is required to meet BC Hydro's goals
BC Hydro's vegetation management practices are aligned to those of Canadian peers with respect to: • Planning cycle and timing • Tree removal decision making criteria • Waste management • Environmental and wildlife impact mitigation • Tool and equipment usage	2021 CEA Vegetation Report	BC Hydro's methods for planning and delivering vegetation management work are consistent with industry standards in Canada

10 Vegetation Management Strategy – Elements and Measures of Success

This section describes how the VMS aligns with the stated goals and objectives and further defines what constitutes success.

Table G-5 Vegetation Management Strategy Elements and Measures of Success

Strategic Objective	Element(s) of Success	Measure(s) of Success	Goal(s) Supported
Plan and implement an effective vegetation management program across the province that ensures sustainable mitigation of the risk posed by regular annual growth, notable events (infestations, droughts, climate impacts, etc.) and storms	**Transmission:** • Full system inspection completed annually • 20 per cent of the full system maintained annually (clearing and hotspotting combined) • Maximum duration between vegetation management cycles is five years • Minimum of 6,700 hectares (minimum stable level) cleared annually in addition to 40,000 hotspotted trees removed by fiscal 2024 • Target 8,600 hectares (optimal stable level with climate uncertainty factor added and VMS goals) cleared annually in addition to 35,000 hotspotted trees removed by fiscal 2025 and this is maintained persistently thereafter • 25,000 edge trees removed per year minimum by fiscal 2024 and beyond	**Transmission:** • Percentage inspection completion • Percentage of system in annual workplan • Percentage of system maintained • No. of hectares cleared • No. of trees hotspotted • No. of edge trees removed	Safety, Reliability, Compliance, Access
	Distribution: • Minimum three-year system inspection cycle, optimally two-year • 17 per cent of the full system maintained annually (pruning) • Maximum duration between management cycles is 6 years • Minimum 3,100,000m of pruning per year by end of fiscal 2025 and persistent beyond • Reach a stable hazard tree removal level (~26,000 to 30,000 trees annually) by fiscal 2024	**Distribution:** • Percentage inspection completion • Percentage of system in annual work plan • Percentage of system maintained • No. of meters pruned • No. of hazard trees removed • maintained by priority	Safety, Reliability, Compliance, Access

Strategic Objective	Element(s) of Success	Measure(s) of Success	Goal(s) Supported
	Access and Facilities: • Access inspections covering 33 per cent of the system minimum annually • 50 per cent of facilities assessed for vegetation need annually • All priority sites identified post inspection maintained within one-year, secondary priority maintained within two years	**Access and Facilities:** • Percentage of access area inspected • KMs of roads maintained • Percentage of facilities assessed • Percentage of identified facilities	
Improve visibility of vegetation across the system and adopt a more dynamic approach of assessing annual workplans that take into account variable growth rates, system conditions and climate impacts	**Transmission:** • Annual LiDAR flights, modelling and analysis covering a minimum of 20 per cent of the system per year. • Adoption of a categorical prioritization approach to vegetation logging • Development of a formal annual transmission inspection report presented to planning and operational leadership teams **Distribution:** • Adoption of a categorical prioritization approach to vegetation logging (e.g., assigning priority to triage work plans) • Development of a formal annual distribution inspection report presented to planning and operational leadership teams	• Percentage of the system scanned with LiDAR • Percentage of the system modelled and analyzed • Transmission vegetation prioritization percentage and volume (e.g., No. of priority areas, percentage of priority areas on system) • Distribution vegetation prioritization percentage and volume (e.g., No. of priority areas, percentage of priority areas on system)	Safety, Reliability, Compliance

Strategic Objective	Element(s) of Success	Measure(s) of Success	Goal(s) Supported
Optimize vegetation management delivery	**Transmission:** • Removal of all historical vegetation accumulation by end of fiscal 2025 by maintaining > 20 per cent of the system annually from fiscal 2021 to 2025 • Annual work process review on a key vegetation process to seek improvement opportunities • Alignment of vegetation activities with the core vegetation management program and others (e.g., stations vegetation maintenance, NIA vegetation activities, etc.)	• Percentage of system cleared annually reaching target of 20 per cent • No. of processes reviewed • Confirmation of alignment	Compliance, Stewardship, Safety, Reliability
	Distribution: • Return to on-cycle distribution pruning by fiscal 2024 • Hazard tree inventory cleared by end of fiscal 2023, sustained thereafter at no accumulation (~26,000 to 30,000 removed annually)	• Percentage of annual work plan delivered on cycle • No. of hazard trees remaining in inventory	Stewardship, Safety, Reliability

Strategic Objective	Element(s) of Success	Measure(s) of Success	Goal(s) Supported
Strengthen compliance assurance within vegetation program delivery and processes	**Transmission:** • Maintain all adopted Mandatory Reliability Standards (**MRS**) for high voltage transmission lines and interties • Maintain all clearances on lower voltage transmission lines • Maintain compliance will all legislative requirements on BC Hydro's vegetation management activities • Sustain Fire Services Agreement with the Government of B.C.	• No. of MRS violations on the transmission system • Confirmed compliance with the following Acts (*Wildfire Act*, *Integrated Pest Management Act*, *Fisheries Act, Water Act*, *Migratory Bird Convention Act*, *Species at Risk Act*, *Provincial Wildlife Act* and the *Heritage Act*)	Compliance, Stewardship, Safety, Reliability
	Distribution: • Maintain compliance with all legislative requirements on BC Hydro's vegetation management activities (same as transmission) • Maintain compliance with respect to traffic control and road safety • Continue to work closely with municipalities and the public to mitigate public and social impacts during the completion of vegetation related activities	• Confirmed compliance with the *Transportation Act*, *The Industrial Roads Act* and the *Motor Vehicle Act*	Compliance, Stewardship, Safety, Reliability

Strategic Objective	Element(s) of Success	Measure(s) of Success	Goal(s) Supported
Maximize efficacy of vegetation investment (e.g., treatment longevity, vegetation and access inspections combined, etc.)	**Transmission:** • One patrol approach through combining vegetation and access inspections to increase overall coverage and a holistic view of vegetation and access needs • Continue annual reviews of pest management plans, herbicide applications and market scans for new and effective vegetation management approaches to preserve or extend longevity of vegetation maintenance activities	• Operationalization of integrated patrol approach • Annual reviews completed each fiscal	Access, Safety, Stewardship, Reliability
	Distribution: • Complete analysis of proactive vegetation maintenance versus reactive trouble activities (est. fiscal 2023/fiscal 2024)	• Completion of vegetation and trouble analysis in fiscal 2024 • Monitoring of percentage of outages that are vegetation originated	Stewardship, Safety

Strategic Objective	Element(s) of Success	Measure(s) of Success	Goal(s) Supported
Secure vegetation management resources and ensure supply	• Annually refresh a long-term vegetation resource requirement and fulfillment plan • Conduct active cost pressure monitoring and annual expenditure adjustments (within RRA cycles) to account for future cost pressures as they are introduced • Complete an internal labour analysis to determine the suitability and commercial impact of in-sourcing vegetation program delivery by end of fiscal 2024 (e.g., establishment of BCH certified utility arborists or extending the role of existing internal resources) • Ensure effective vegetation category management and procurement	• Confirmation of annual resource plans • Annual cost pressure analysis conducted • Completion of internal labour analysis by end of fiscal 2024 • Vegetation contracts secured until end of fiscal 2025 • Vegetation category management strategies (contract work & LiDAR) completed and implemented by end of fiscal 2023	Stewardship, Safety, Reliability, Compliance
Manage climate change impacts and risks (e.g., wildfires, storm resiliency, tree health from drought, flooding, disease and other impacts)	• Assess climate change impacts and notable trends emerging on the system province wide • Refresh of wildfire risk model • Continued adherence to fire prevention techniques	• Completion of climate change impact on vegetation report • Updated wildfire risk model • Power system related fire report	Compliance, Safety, Reliability, Stewardship

11 Vegetation Management Strategy – Capabilities Required

The following section will describe the core capabilities required by BC Hydro and the assessment of the current resources and processes in place to deliver on the VMS.

The core capabilities are broken into four categories:

- Vegetation visibility (BC Hydro's ability to inspect and assess vegetation);
- Executability (ability to deliver work in the field);
- Management and support (oversight, administration and ancillary functions); and
- Planning and strategy (program evolution in response of changes, certified professional oversight, compliance leads, workplan development, program leadership, etc.).

Within each of these capability categories, there are people, process and technology elements that were assessed. Each assessed capability was assigned one of three statuses:

1. Adequate based on fiscal 2022 levels to meet future needs;
2. Capability growth required for optimal outcome; or
3. Capability not performing as needed.

These were then assigned a colour (green, yellow or red, respectively), as summarized in Table G-6 below.

Table G-6 Vegetation Management Strategy Capabilities Assessment

	VEGETATION VISIBILITY	VEGETATION MAINTENANCE	MANAGEMENT & SUPPORT	PLANNING & STRATEGY
PEOPLE	🟡Vegetation Coordinators 🟢Geomatics 🟢Engineering 🟢Vegetation Planners	🟡Vegetation Coordinators 🟢Vegetation Contractors 🟢BCH Foresters	🟢PCM Management 🟡Category Management	🟢Vegetation Planners 🟢IP Leadership 🟢Operations Leadership
PROCESS	🔴Manual patrol delivery & QA 🟡LiDAR acquisition to end use 🟡Visibility data to veg targeting 🟢Inventory collection & prioritization	🟡Field plans & delivery 🟢Delivery QA 🔴Site prescriptions 🟡Customer consultation & engagement	🟢Team management 🟡Vendor & contract mgmt. 🟡Performance mgmt. 🟡Reporting, documentation and records	🟢Program development 🟢Resourcing and planning 🟢Vegetation strategy 🟢Compliance leadership
TECH	🟡SAP 🟡Passport 🟡SAM 🟡VegNET 🟡PLS CAD 🟡Powerline 🟢PowerOn 🟡CROW	🟡SAP 🟢Passport 🟡SAM 🟢VegNET	🟡SAP 🟡Passport 🟡SAM 🟡VegNET	🟡SAP 🟡Passport 🟡SAM 🟡VegNET 🟡PLS CAD 🟡Powerline 🟢Tableau

🟢 = Capability adequate based on F22 levels 🟡 = Capability growth required for optimal 🔴 = Capability not performing as needed

The proposed VMS will address the capabilities required to achieve the program goals between fiscal 2023 and fiscal 2025 and then sustain the full capability suite thereafter. The following is a summary of the incremental resources proposed and the affected capabilities.

Table G-7 Capability Growth Under the Vegetation Management Strategy

Change Category	Capabilities Reinforced
Incremental Vegetation Coordinators +6 FTEs (incremental coordinators in operations for fiscal 2023+)	**Vegetation Visibility:** Coordinators, Manual Patrols & QA **Vegetation Maintenance:** Coordinators, Field Plans & Delivery, Public Consultation and Engagement
Incremental Vegetation Specialists and Foresters +2 FTEs (incremental specialists in operations for fiscal 2023+)	**Vegetation Maintenance:** Site Prescriptions
Operationalization of the BC Hydro Vegetation LiDAR Program	**Vegetation Visibility:** LiDAR, Vegetation Data and Targeting
Vegetation Systems and Reporting Enhancement Roadmap	**All Technology Categories:** Business case development and investment justifications for enhancements within the annual IT capital and maintenance plans **Management & Support:** Reporting, Documentation and Records, Performance Management
Category Management Strategy & Market Procurements	**Management & Support:** Category Management, Vendor & Contract Management

In total, this represents eight incremental FTEs being added between fiscal 2023 and fiscal 2025, all within the Operations Business Group in BC Hydro. With these additions to the base complement, it is believed that the capabilities and internal resources required to delivery the VMS will be suitable for the next three years and further assessment is expected annually as enhancements are realized.

12 Performance Metrics and Evaluation

Vegetation maintenance is a significant undertaking for BC Hydro and involves considerable investment in both time and resources. In order to support the long-term successful delivery of vegetation management work, there is an ongoing need for performance metrics and program evaluation. This is required in order to both ensure appropriate management and oversight in addition to understanding key comparators to the industry and market. This information is used to shape the ongoing program, identify sources of business opportunity and communicate outcomes to both internal and external stakeholders.

Although there has been robust reporting in place for many years, an objective of the VMS is to formalize and improve visibility of performance metrics and program evaluation in addition to enhancing the overall complete suite of analytic capabilities. Moving from the status quo to the full operationalization of the proposed reporting and metrics will be undertaken in accordance with the initiative described as Vegetation Management Performance & Evaluation Enhancement Initiative (refer to Key Pursuits and Activities section for details on timing and scope). In addition to enhancing and formalizing reporting, the initiative will also focus on the integration of source data systems and reporting automation. This will ensure key information is identified without manual effort, delivering operational and planning insights in a regular and timely fashion to those that need it to inform decisions.

At the core of the Vegetation Management Performance & Evaluation Enhancement Initiative are three primary approaches to support performance and evaluation:

- Regular automated reporting and re-occurring studies or audits;
- Compliance reporting; and
- Planned analysis focused on specific areas of interest or improvement.

12.1 Regular Reporting

The regular automated reporting and re-occurring studies or audits are intended to cover a series of business needs. Shorter frequency, more detailed reports are in direct support of operational management and oversight, whereas higher level and more periodic reports are for senior audiences and executive reviews to assess general program performance towards stated outcomes. Additionally, annual benchmarking studies and regular audits (e.g., WECC Audit for Mandatory Reliability Standard FAC-003) are to understand context of performance relative to other utilities and compliance assurance, respectively. The cumulative effect of all these various reporting measures ensures both timely and contextual insight into how the vegetation management program for BC Hydro is performing and managed. The following is a summary of these reporting vehicles, inclusive of frequency.

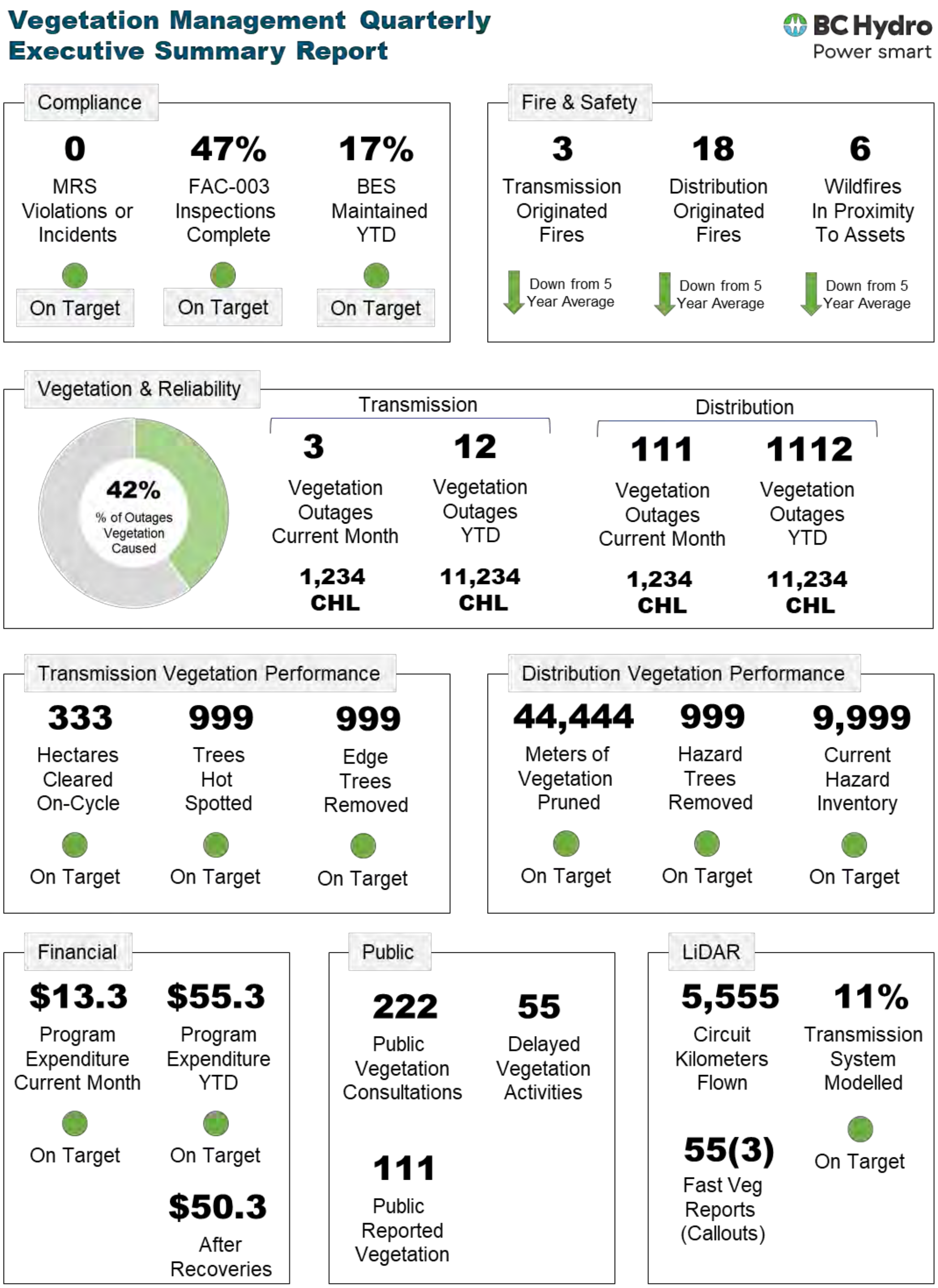
Table G-8 Summary of Vegetation Management Reports and Evaluation

Report / Study Name	Purpose	Audience	Frequency
Weekly Operations Report	The purpose of the weekly operations report is to provide front line managers with the information required to understand regular delivery activities in addition to ensuring regular and timely collection of data and insight	• Front line managers • PCM managers • Planning leads	Weekly
Monthly Vegetation Management Report (Detailed)	The purpose of the monthly vegetation management report is to provide broad awareness of the progress of the overall vegetation management effort to a broad audience at a detailed working level	• Front line managers • PCM managers • Planning leads • Responsible Directors • Compliance Leads • Cross Functional • Supporting Individuals • Responsible • Executives	Monthly

Report / Study Name	Purpose	Audience	Frequency
Quarterly Vegetation Management Executive Summary	The purpose of the quarterly vegetation management executive summary is to provide broad awareness of the progress of the overall vegetation management effort to senior level individuals	• Responsible Directors • Responsible • Executives	Quarterly
Asset Planning Monthly Dashboard	The purpose of this dashboard is for Asset Planning management and leadership to review key performance indicators from various programs, including the vegetation management program	• Asset Planning • Leadership Team • Integrated Planning • Leadership Team	Monthly
Executive Summary Presentations	The purpose of these presentations is to provide an overview of the vegetation program execution to the Executive Team	• Executive Team	As requested
Annual First Quartile Benchmarking Study	The purpose of the annual First Quartile Benchmarking Study is to understand BC Hydro's relative performance to industry peers and gain insight into industry themes and trends	• Planning Managers • Operations Managers • Responsible Directors • Responsible • Executives	Annual
WECC Audit Findings Report	The purpose of the WECC audit for vegetation management (FAC-003) is to ensure utility practices are suitable for maintaining compliance with Mandatory Reliability Standards	• Planning Managers • Operations Managers • Responsible Directors • Responsible • Executives	Every 36 Months

Figure G-8 below provides an illustrative example of the quarterly executive summary. The specific metrics and reported details will be developed during the course of fiscal 2022 as one of the initiatives completed as part of the VMS. The example is for illustration purposes only.

Figure G-8 Illustrative Example Quarterly Vegetation Executive Summary Report



* Actual report to be developed in fiscal 2022 as part of the delivery of the VMS. Illustration purposes only.

12.2 Compliance Reporting

Compliance reporting is crucial in order to provide the evidence necessary to validate ongoing achievement of compliance (e.g., FAC-003, Wildfire prevention, etc.). Reporting for the purposes of compliance is defined by the individual compliance requirements, inclusive of formats, timeframes and content. The general themes consistent with compliance requirements are as follows:

1. Eliminate grow-into outages and minimize risks from fall-into tree outages;
2. Implement a well-documented program that addresses all rated operating conditions taking into account line sag/sway and effects of line load, weather, vegetation growth, etc. to avoid vegetation encroachments;
3. Ensure a clear communication process in the event you have imminent risks;
4. Implement mitigation strategies to deal with work that may be deferred because of permits, disputes, etc.;
5. Complete annual documented patrols of the entire system; and
6. Implement documented annual work plan and tracking and quality reviews to assure that all planned work is completed and that no outstanding risks are left before next maintenance cycle.

12.3 Planned Analysis

Planned analysis is another method of performance management for vegetation maintenance. This approach relies on the identification of a potential opportunity or hypothesis for improvement and then a tailored analysis to understand the contemplated change. Each of these will be summarized with key findings and recommendations as completed. Examples of specific analysis undertakings include the following:

Table G-9 Planned Analysis – Initiative Based

Key Question	Initiative*	Timeframe
Are vegetation management external contracts cost effective?	Category Management Analysis	Fiscal 2022 and fiscal 2023
Are there financial and reliability benefits for proactive vegetation management work versus trouble response?	Proactive Vegetation Management Versus Trouble Cost Analysis	Fiscal 2022 to fiscal 2025
Are there financial and operational benefits to utilizing internal resources for vegetation management?	Internal Labour Utilization for Vegetation Management Analysis	Fiscal 2024
Are cost increasing faster than program resources?	Annual Cost Pressure Analysis	Annually

* Refer to the Key Pursuits and Activities section for additional details

Combining the use of multi-level regular reporting, re-occurring studies, compliance reporting and planned analysis, BC Hydro will be well positioned to ensure the effective delivery of vegetation management efforts. This suite of information directly enhances operational delivery oversight, long-term planning capabilities, quality assurance practices and compliance assurance. The range of activities also spans internal and external sources to ensure that there is a deep understanding of the insights produced in context of the broader utility industry. This will enable BC Hydro to maintain confidence in its delivery practices and ensure value for ratepayers in British Columbia.

13 Key Pursuits and Activities

BC Hydro recognizes that well performing vegetation management both requires ongoing, regular work programs to address growth and re-growth in addition to deliberate projects or work efforts to improve the overall capability to manage vegetation holistically. Evolving the program to take advantage of new technologies, market opportunities, process efficiencies and adapting to cost pressures and regulatory changes are all examples of changes that ensure long term efficacy. As such, beyond the delivery of regular vegetation management efforts, the VMS includes a series of key pursuits and incremental activities to the base work. These are each intended to be delivered in a project-based fashion and have scope, timing, resource and cost dependencies individually. Furthermore, as additional information becomes available and the new VMS is implemented, these pursuits will change and adapt to the needs present within each year's annual work plan.

The following are a summary of these pursuits as they are contemplated at this time:

Table G-10 Summary of Initiatives, Pursuits and Studies

Initiative	Description	Desired / Potential Outcome(s)
Integrated Vegetation Visibility Enhancement Initiative	There are currently several means in which BC Hydro gathers information on the state of vegetation across the electrical system. These include patrols, surveys, public reports and studies. The purpose of this initiative is to optimize the benefit and usefulness of the full breadth of information gathered by all means of collection to drive efficient realization of vegetation management goals. This initiative will span people, processes and technologies to manifest a deliberate ecosystem of inputs and outcomes that collectively represent an effective vegetation visibility and targeting capability.	Operationalization of an integrated vegetation visibility capability (including patrols, LiDAR, reports, studies, etc.) enabling the effective, efficient and prioritized targeting of vegetation management.
LiDAR Operationalization and Optimization	On ongoing LiDAR program covering a minimum of 20 per cent of the system per year will need to be operationalized across a number of internal BC Hydro teams and external parties. Geomatics, Engineering and Vegetation Planning will all require new processes and technology solutions to support the incremental LiDAR information and end use cases. Additionally, a category management strategy for vendor management will also be developed in support of this initiative.	A smooth operational process that receives cost effective LiDAR scan data and achieves the desired vegetation business outcomes post modelling and interpreting, enabling effective program targeting for transmission maintenance.

Initiative	Description	Desired / Potential Outcome(s)
Vegetation Management Performance & Evaluation Enhancement	Vegetation management represents a significant proportion of BC Hydro's annual operating and maintenance expense. As a key portfolio, it is regularly required to assess and communicate the efficacy of the end to end program effectiveness. This is done through the regular use and combination of internal metrics, external benchmarks (First Quartile, CEA, EPRI, etc.), industry resources (whitepapers, comparison studies, etc.), peer to peer engagement and consultants. The purpose of the vegetation management evaluation initiative is to develop an orchestrated regular suite of KPIs and comparators that will be used to communicate program details on a monthly basis, satisfying the need of both internal and external stakeholders. The goal is to enhance the current suite of metrics while improving the means in which information is gathered.	Improved awareness of vegetation management performance and accessibility of key performance indicators. Improved capability to manage the program in context and make determinations of where changes may be needed. Proactive insight about the overall program health and achievement of work.
Vegetation Management Longevity Study	The nature of vegetation management is an ongoing cycle between management efforts and regrowth. Growth rates are largely dependent on environmental and climate factors (precipitation, sun, temperature, etc.); however, there are means of extending the longevity of vegetation management efforts. Examples include the use herbicide, clearing techniques, landscaping, public engagement (preferential species selection, planting locations, etc.) and partnerships. BC Hydro will engage a study to assess the means of longevity extension and determine if any are favourable to implement into the regular delivery of vegetation work.	Longer persistence of vegetation management benefits resulting in incremental realization of the program's goals. Repeatable and reliable extensions of longevity could safely extend cycle times or reduce vegetation management needs in remote areas.

Initiative	Description	Desired / Potential Outcome(s)
Vegetation Work Consolidation Initiative	At present, in addition to the primary provincial vegetation management program, there are other vegetation related efforts occurring in isolation; namely at facilities (generation, substation, etc.), roads and access and non-integrated areas. Although small by comparison, there may be opportunities to realize benefits from alignment of these various efforts and ensure completeness for understanding the full breadth of vegetation management efforts across the company. Furthermore, there are robust linkages between roads and access and vegetation related work that will need to be studied to optimize both programs, improve access and reduce risk in remote areas.	Synergies in program deliveries, improve coordination of access with respect to vegetation, better prioritization capability, incremental utilization of manual patrols, reduced risk, improved reliability.
Vegetation Management Rights and Obligations Initiative	Over time, even the best designed structures, processes and systems experience gradual incremental changes as present needs drive minor changes into the business. Churn in particular roles, restructuring of teams, introducing new processes or systems, adding external compliance requirements and time are all examples of small, but cumulative changes that large-scale programs experience. After an extended period of time, organizational entropy can occur which leads to more effort being required to realize the optimal state of delivery. The goal of the rights and obligations initiative is to assess the status quo in terms of team structures and roles to either validate the current state as optimal or modify the current state to one that is optimal.	Improved inter-team collaboration, clarity of accountability and responsibility, reduction of potential gaps or overlaps.
Vegetation Management Work Process Review	Intended to follow the Vegetation Management Rights and Obligations Initiative, an annual process review focused on the key delivery areas will ensure alignment between roles and ensure they are optimal. Additionally, this initiative will assist in documenting how processes are delivered and aligned to the program goals, supporting future reviews, audits and regulatory proceedings.	Process efficiency, audit preparedness, delivery alignment and efficiency.

Initiative	Description	Desired / Potential Outcome(s)
Vegetation Resource Assurance Plan	Vegetation management is a resource intensive activity that requires a regular supply of qualified professionals to deliver. The purpose of this initiative is to establish a long-term sourcing plan that will align to the vegetation program needs. It is anticipated to include both an internal and external assessment that combined form a complete resource assurance plan.	Firm and cost-effective resource assurance for ongoing vegetation program delivery.
Proactive Vegetation Management Versus Trouble Cost Analysis	One of the contributing causes of outages and system damage is contact with vegetation. Proactive pruning, removal of hazard trees and other vegetation management efforts can reduce the potential for system contact during storms and weather events. The purpose of this initiative is to evaluate the cost effectiveness of incremental upstream vegetation management effort versus restoration efforts following a trouble event. The analysis will look at both the operational costs in addition to the system outcomes (e.g., improved reliability, safety, etc.) over a number of years to determine if a business case exists for broader proactive vegetation management efforts.	If a favourable relationship exists and can be repeatedly demonstrated, a business case will be developed for incremental upstream vegetation management efforts to proactively reduce the probability of trouble events.
Internal Labour Utilization for Vegetation Delivery Exploration	At present, all vegetation management delivery engaged by BC Hydro across British Columbia is conducted by external third parties, governed by a series of contracts with oversight from BC Hydro employees. There are utilities that utilize employees to perform vegetation management delivery and BC Hydro will explore the potential of this model. Furthermore, opportunities to expand existing field roles to include vegetation management elements may be a means of improving labour utilization in some areas of the province while also providing staff with additional opportunities to grow skillsets and diversify their working portfolios. It is recognized that this study will include a number of complex factors, including but not limited to engagement with employee relations, human resources, unions, existing employees and external parties to fully evaluate the potential benefits, detriments and scope of possibility for making a change of this nature.	Cost savings for the delivery of regular, localized and repeatable vegetation work. Potential opportunity for improved resource utilization (both equipment and labour). Efficiencies of work delivery for vegetation related system impacts.

Initiative	Description	Desired / Potential Outcome(s)
Vegetation Impacts from Climate Change Study	Vegetation across the province is highly susceptible to changes in environmental conditions and resulting occurrences (e.g., infestations, disease, etc.). It is globally recognized that climate change is occurring and to the extent that it impacts BC Hydro's system as a result of vegetation impacts has not been actively studied, although visible evidence of impacts is apparent. The purpose of this study is to formally assess the historic impacts and project impacts into the future to improve long term planning and guide actions in the present that can mitigate detriments from climate change.	Improved planning to mitigate climate change impacts, proactive preparation for broad scale climate events, improved program performance through future planning.
Fire Prevention and Mitigation Plan	One of the largest ongoing threats to public safety and the electrical system is fire. Fires originating naturally (e.g., wildfires caused by lightning strike) can damage remote electrical infrastructure and impact communities far away, all the while impeding restoration efforts. Fires can also be started by the electrical system where vegetation contact is a primary ignition driver. The purpose of this plan is to proactively address and mitigate fire related system risks and vulnerabilities. Activities ranging from ROW widening, incremental vegetation waste product removal, chemical fire retardants, line ratings and system enhancements (e.g., lateral reclosers) can all produce fire mitigation benefits for BC Hydro and for the public. This plan is intended to evaluate various options and advance a suitable suite of fire prevention and mitigation activities as they relate to vegetation.	Improved safety, reliability and compliance.

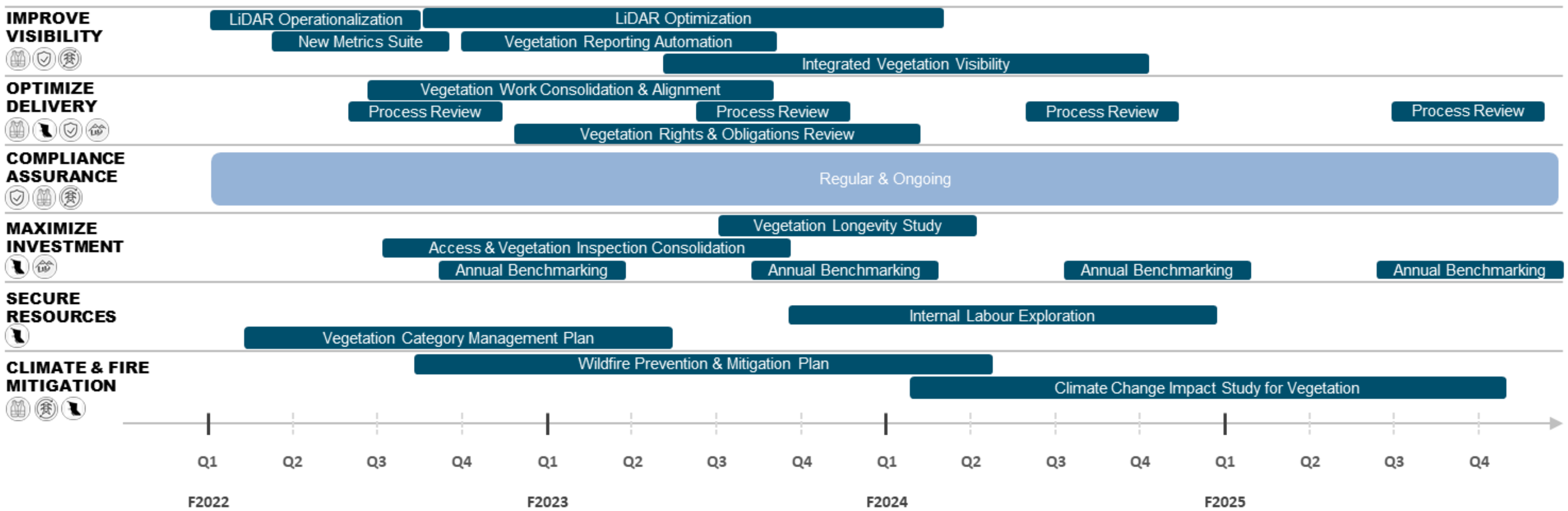
14 Proposed Workplan – Beyond Base Maintenance Work

The following is the proposed workplan covering the new VMS initiatives that extend beyond the scope of base work. The workplan and schedule below is at a higher level of detail than the initiatives and some initiatives have been represented by their individual scope below and shown in chronological order.

Table G-11 Proposed Workplan and Schedule

Workplan Item	Schedule	Business Units
LiDAR Operationalization & Optimization	Q1 F22 → ongoing	Integrated Planning, Supply Chain
New Vegetation Metric Suite	Q2 F22 → ongoing	Integrated Planning, Operations
Vegetation Reporting Automation	Q3 F22 → Q2 F23	Integrated Planning, Operations, Technology
Annual Process Review and Optimization	Annual (1 core process per year)	Integrated Planning, Operations
Access & Vegetation Inspections Consolidation	Q3 F22 – Q4 F23	Integrated Planning, Operations
Refresh Vegetation Long Term Resource Plan	Annual – Q4	Integrated Planning, Operations, Supply Chain
Vegetation Longevity Study	Q3 F23	Integrated Planning
Vegetation Category Strategy	F22 – F23	Supply Chain, Integrated Planning
Climate Impact on Vegetation Study	F24 – F25	Integrated Planning
Internal Labour for Vegetation Delivery Exploration	F23 – F24	Integrated Planning, Operations, Human Resources, Employee Relations
Integrated Vegetation Visibility Initiative	F23 – F24	Integrated Planning, Operations
Annual Benchmarking	Annual – Q4 F22 → Ongoing	Integrated Planning
Proactive Vegetation Versus Trouble Analysis	Monitored Annually	Integrated Planning, Operations
Vegetation Consolidation Initiative & Rights and Obligations	Q3 F22 – F23	Integrated Planning
Wildfire Prevention & Mitigation Plan	Q3 F22 – F23	Integrated Planning, Operations

Figure G-9 Proposed Workplan and Schedule GANTT Chart (By VMS Objective)



15 Related Documents and References

Guidehouse Review of the BC Hydro Vegetation Management Strategy

- Conducted Q1 fiscal 2022
- Format: Summary presentation and letter

Canadian Electrical Association 2021 Vegetation Management Report

- Conducted spring 2021
- Format: PDF Report

First Quartile Utility Benchmarking – Vegetation Focus (Annual Reports)

- Conducted annually
- Format: Summary Presentation, Raw response data (confidential)

Hydro One Rate Applications

- Publicly accessible regulatory filing
- https://www.hydroone.com/abouthydroone/RegulatoryInformation/txrates
- https://www.hydroone.com/about/corporate-information/vegetation-management/practices

Hydro Quebec (various publications)

- Publicly accessible publications
- https://www.hydroquebec.com/documents-data/official-publications/

Manitoba Hydro Rate Application

- Publicly accessible regulatory filing
- https://www.hydro.mb.ca/regulatory_affairs/electric/

- https://www.hydro.mb.ca/docs/regulatory_affairs/projects/mmtp/epp_integrated_vegetation_management_plan.pdf

ATCO Vegetation Management Practices

- https://test.atco.com/content/dam/web/for-business/infrastructure-services/Vegetation-Management-brochure.pdf

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix H

Fiscal 2022 to Fiscal 2031 Capital Plan

~~CONFIDENTIAL -~~ Discussion/Information

2.4 Annual 10 Year Capital Plan

Executive summary

This briefing provides a summary of BC Hydro's updated Capital Plan (Capital Plan) with an outline of the overall Capital Plan composition, excluding Site C, as well as retained risks and uncertainties across the portfolio. The Capital Plan is presented to the Capital Projects Committee of the Board of Directors annually and supports BC Hydro's Service Plan update and the upcoming Revenue Requirements Application (RRA).

The Enterprise Capital Planning process strives to balance affordability for BC Hydro customers with an appropriate level of retained risk and impacts to system performance. This Capital Plan achieves key strategic objectives including investing to address compliance, addressing our highest safety risks and preserving the reliability of the Key generating facilities and the bulk electric system. Since the approval of the Previous Plan, changes in the portfolio composition have increased the amortization and dismantling impacts. These changes include addressing increasing needs for the Supporting Portfolios (Technology, Properties, and Fleet Services) in the near-term years of the Capital Plan and increases to the customer driven capital expenditures net of contributions in aid. To address these changes while maintaining an appropriate level of risk within the Power System portfolio, there is a marginal increase to the rate impact of the Capital Plan in comparison to the Previous Plan.

To balance affordability with system performance and risk, some investments were deferred in the near years of the Capital Plan. The retained risks associated with the deferrals were evaluated and are considered to be manageable. These risks will be monitored, and adjustments will be made in the next capital planning cycle if appropriate. Funding levels for the Supporting Portfolios will also be re-evaluated as part of the next capital plan in support of initiatives such as the Greenhouse Gas (GHG) Management Plan and the Long-Term Workplace Strategy, as well as a level of funding in the Technology portfolio to manage risks and deliver on improvements to business capability over the longer term.

This Capital Plan has been developed in consultation with Project Delivery and Program and Contract Management. Resource risks and mitigation strategies have been identified and where required adjustments have been made to the capital investments to address potential near-term overloading of Engineering and Operations resources. Due to uncertainties related to ongoing COVID-19 protocols and Mandatory Reliability Standards (MRS) demands there will be an increased reliance on the 2 – 12 month resource forecasts and escalation process to monitor and adjust the detailed Operations work plans in the near term of the plan.

Background

Over the past year the capital planning schedule has been adjusted to accommodate the F2022 and F2023 – F2025 RRA filing schedules. Capital Planning activities to develop this updated Capital Plan began in February 2020, were put on hold in September 2020, and then were re-initiated in December 2020 including updating active project forecasts as of January 2021. This Capital Plan will form the basis of the capital expenditures included in BC Hydro's F2023 – F2025 RRA, expected to be filed in August 2021.

~~CONFIDENTIAL -~~ Discussion/Information

2.4 Annual 10 Year Capital Plan

Financial and Strategic Directions for the Capital Plan Process

The F2022 – F2031 Enterprise Capital Planning process began with defining business group level capital additions targets. Initial targets were set based on the strategic objective to maintain a rate neutral impact when compared to the Previous Plan in the front five years of the capital plan horizon. This includes consideration for amortization as well as OMA expense items related to capital, such as Capital Project Investigation funding and Dismantling.

Public and Worker safety continues to be the highest priority for capital investments, and re-direction of funding to the Supporting Portfolios in the near years of the plan was done in support of corporate wide priorities such as "Make it Easier to Get Work Done". This Capital Plan includes increased investment to support BC Hydro's MRS Program, and ensures sufficient funding for the investments required to meet the Federal Polychlorinated Biphenyl (PCB) Regulation deadline of December 31, 2025.

Main Investment Drivers

While the detailed investments within each portfolio change with every capital plan update, there are several key drivers across the enterprise portfolio:

Ageing Assets – A large portion of BC Hydro's system was built in the 1960s and 1970s and is reaching or exceeding expected end-of-life. A significant proportion of the risks facing BC Hydro's major assets can be attributed to their age. The physical condition, performance, maintenance history, and criticality of equipment and facilities are significant drivers for planning and prioritizing refurbishment or replacement.

Reliability – Capital investment is paramount to the total performance of the system, and the indicators of investment adequacy are consistent performance metrics over time and the number and impact of in-service failures on critical assets. The F2021 SAIDI and SAIFI results of 3.27 and 1.49 were slightly above (2 per cent and 6 per cent) their targets of 3.20 and 1.40, respectively. However, SAIDI and SAIFI measures within 10 per cent of targets are considered acceptable. The BC Hydro Service Plan sets targets for system performance measures based on longer-term trends and expected longer-term investment plans; these lagging indicators continue to indicate that BC Hydro is appropriately managing our service performance risks.

Compliance and Resiliency – The identification of capital investments to address environmental compliance, MRS and cybersecurity has continued over the past capital planning cycle. The Capital Plan includes investments to address the PCB Regulation deadline of December 31, 2025. In addition, the Capital Plan includes funding for the successful implementation of the latest version of Critical Infrastructure Protection (CIP) standards (NERC CIP-003 version 7), and physical security zone improvements at Key generation facilities. As key activities in the area of compliance progress in the coming fiscal year, additional capital investments may be identified that will need to be initiated as ex-plan or included in future capital plan updates.

Growth – While the overall level of investment in growth has moderated over the past few years, aligning with the trend in the load forecast, new investments continue to be required for both distribution and transmission infrastructure to meet regional customer demand growth. Investments within this Capital Plan are aligned with the System Load Forecast dated December 2020, and the Substation Load Forecast dated November 2019. Investments to address forecasted load growth now represent only a small proportion of the overall Growth expenditure portfolio.

BC Hydro
Power smart

~~CONFIDENTIAL -~~ Discussion/Information

2.4 Annual 10 Year Capital Plan

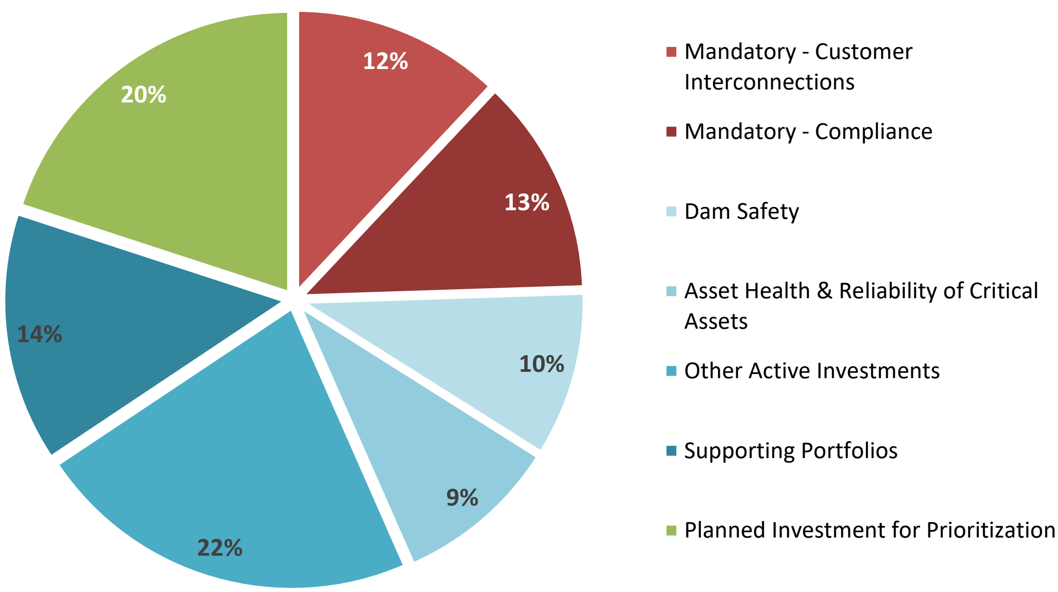
A significant proportion of the remaining Capital Plan growth expenditures are required to connect new supply of electricity based on customer requests and are considered Mandatory. The balance of the Growth portfolio is required to mitigate other system risks such as providing reliable service and/or allowing for the retirement of end-of-life assets. Examples include the construction of a new line to West Kelowna and a new substation in the West End of Vancouver to allow for the offloading of Dal Grauer substation. Even though these investments may be driven by the need to sustain the existing system, as is the case in the latter example, they are classified as Growth expenditures in the Capital Plan because they are adding new assets to the Power System.

Business Needs – The increasing prevalence of technology, particularly amidst the COVID-19 pandemic, changing employee needs, and the Vehicle Frontline Alliance Team (VFLAT) outcomes related to continued standardization, drive some of the investments associated with the Supporting Portfolios: Fleet Services, Technology, Properties, and Tools/Other.

Capital Plan Composition

The following chart outlines various components of the capital investments included in our updated Capital Plan after prioritization and are shown as the percentage of capital additions in the F2022 – F2027 period.

Figure 1: F2022 - F2027 Capital Plan composition by Prioritization Category

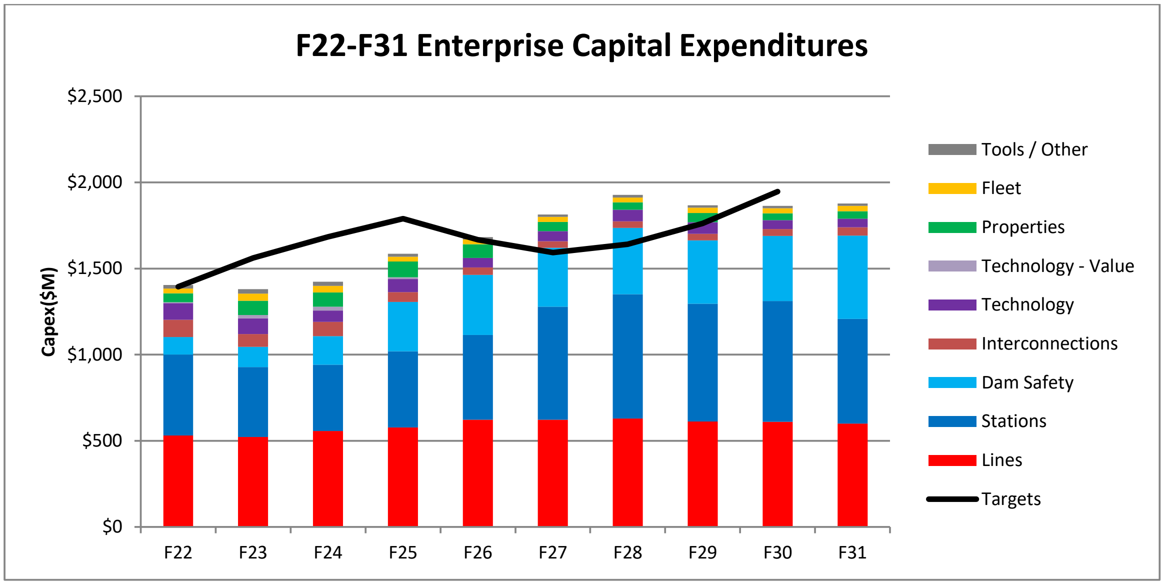


BC Hydro is forecasting net annual average capital expenditures of approximately $1.68 billion[1] per year or total net capital expenditures of $16.83 billion[1] over F2022-F2031. For capital additions, BC Hydro is forecasting a net annual average of approximately $1.63 billion[1] per year, or total net capital

[1] Excludes Site C and BC Hydro Subsidiaries

additions of $16.29 billion[1] over F2022-F2031. Figures 2 and 3 below show the capital expenditure and additions breakdown across the Enterprise Portfolio. A tabular representation of the capital expenditures and additions by category is included in the appendices.

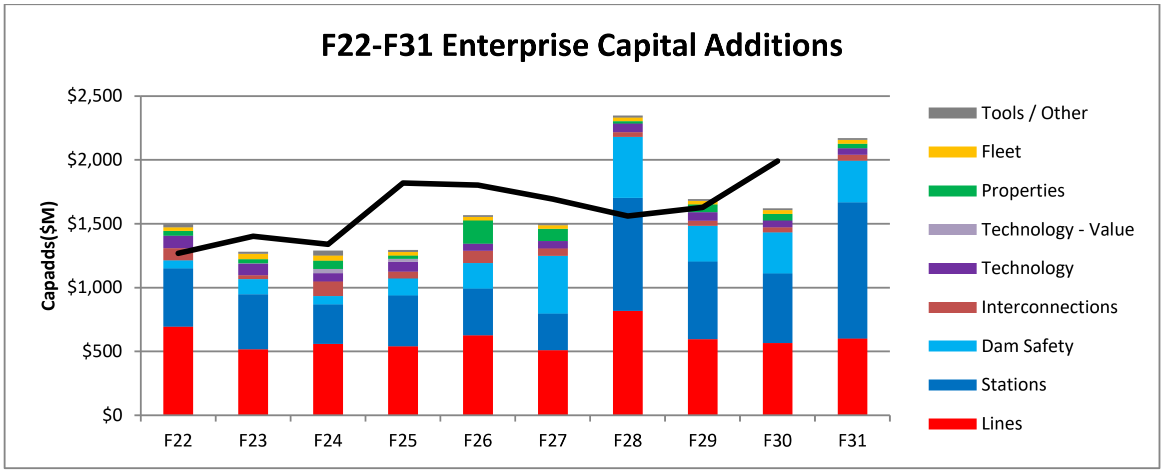
Figure 2: F2022 - F2031 Capital Expenditure



For the early years of the Capital Plan, BC Hydro is in a level of lower annual capital expenditures compared to levels seen in the past decade. Over the longer period, the increasing capital expenditure profile is driven by Project Delivery's forecasts for many large active projects that will be entering the Implementation phase in coming years, including the Strathcona Upgrade Discharge, John Hart Dam Seismic Upgrade, and Peace to Kelly Lake – Stations Sustainment projects. There are also a number of major projects expecting to have high capital expenditures after the F2027 period most notably the West End – Substation Construction and System Reinforcement and the La Joie Dam Improvement projects. While full investment level planning and prioritization was not completed for the F2028 – F2031 period, the updated forecasts for these larger active projects are indicating a need for sustained higher levels of investments in the latter years of the plan. Further discussion on the execution and resource risks associated with this Capital Plan are outlined below.

2.4 Annual 10 Year Capital Plan

Figure 3: F2022 - F2031 Capital Additions



The variations in the capital additions profile, shown in Figure 2, are driven by the in-service dates of large projects. In F2028, the capital additions include Peace to Kelly Lake – Stations Sustainment, Seton – Upgrade Unit and the System Wide – Bulk Electric System Telecom Equipment Replacement projects as well as the impact of the Project Delivery risk adjustment that is shifting forecasted additions from earlier years into F2028. The F2031 capital additions forecast is largely driven by the West End – Substation Construction and System Reinforcement forecast in-service date.

Uncertainties to Monitor

There are a number of uncertainties, within the Power System, Technology, Properties, and Fleet portfolios, that will need to be monitored for impacts on the Capital Plan. The base Capital Plan includes higher projected investments for Distribution Major Load and Transmission Interconnections but does not include all investments required to achieve BC Hydro's Electrification Plan or the Government of British Columbia's Clean BC Initiative. The incremental investments required to support BC Hydro's Electrification Plan are estimated to be between $25 to $75 million to connect new Transmission and Distribution Loads. Similar to the Previous Plan, expenditures related to the CleanBC initiative and the Revelstoke Unit 6 projects have been included in the Capital Plan to the current approved funding phase only. These investments will be added to the Capital Plan once firm load commitments are made by our customers. These investments will be offset by increased revenue projections to ensure the rate impacts of the Capital Plan remain neutral to the Previous Plan.

In addition, the level of growth investment has been moderated compared to previous plans. This means that higher than forecast load increases, where there are constraints on the system, will require offsets through mechanisms like demand-side-management and time of use rates. Otherwise higher levels of growth capital investment will be required to address system constraints. Electrification efforts and customer interconnections will also place demands on capital and resources as well as Capital Project Investigation (CPI) funds.

MRS and Cybersecurity activities may identify the need for additional capital investments on the Power System beyond what is currently included in the Capital Plan. This may also impact the demand for and prioritization of work for Technology.

2.4 Annual 10 Year Capital Plan

Finally, some strategies and plans were not approved as of the January 2021 currency date of the Capital Plan. The Long-Term Workplace Strategy has not yet been finalized and so the Properties portfolio does not include any investment related to a hybrid working environment. Also, the Capital Plan does not reflect the investments required to meet the CleanBC goals outlined in the Greenhouse Gas Management Plan, which was endorsed after the finalization of the Capital Plan. Investments to meet BC Hydro's Long-Term Workplace Strategy and CleanBC goals will be included in future capital plan updates.

Power System

After capital additions targets were set at the Enterprise Portfolio level, the Power System targets were set for each sub-portfolio. Cross portfolio reviews focused on ensuring the retained risks were comparable across the Power System.

Dam Safety

Dam Safety risk reduction targets remain as they were in previous Plans and align with the approach that was approved by the Board in 2014; to "manage the whole fleet of dams so that there is no significant deterioration in the risk position and that the overall level of risk is kept well within the limits considered to be tolerable." In practical terms, this Capital Plan aims to reduce the aggregated Vulnerability Index of issues identified in the Dam Safety Issues Database at a rate that will generally offset the historic (and expected) rate of additions to the Vulnerability Index through newly identified or understood issues.

This Capital Plan continues to prevent deterioration of the current risk profile related to BC Hydro's dams and reservoirs and will address several issues that significantly contribute to that risk. It provides for major seismic and spillway gate reliability upgrades to the Campbell River System and Mica Dam spillway, seismic upgrades to La Joie Dam and the Alouette-Stave tunnel and provides for flow control improvements and associated reduction of public safety risk along the Puntledge River.

While continuing to broadly meet the Dam Safety program's risk reduction targets, the size of the Dam Safety portfolio – specifically In-Service Additions in the period F2022 through F2027 – has been reduced by approximately ten percent within this latest version of the Capital Plan. This is primarily as a result of a number of deferrals of project releases. In some instances – such as at Duncan, Sugar Lake, Walter Hardman and Whatshan Dams – these deferrals accommodate the time required to complete precursor Dam Safety Investigations. Some other project releases have been deferred to reduce the number of concurrent projects in a region, such as the canal refurbishment and left dyke upgrade at Seton, or to reduce demands on a specific resource, such as the spillway gate system reliability upgrades at Seven Mile Dam. Finally, a handful of investments have been deferred by one or two years primarily for the purpose of balancing affordability with system performance and risk. These projects – at Bear Creek and Terzaghi Dams, on the Wahleach tunnel intake, and a second tranche of reservoir boom replacements at various sites – have relatively small impacts on the portfolio's risk profile that can be managed and/or tolerated in the interim.

Stations Asset Planning - Generation

The Generation portion of the Stations Asset Planning portfolio continues to focus on preserving a high level of reliability at our seven Key facilities which provide 90% of the average annual electricity generated by BC Hydro. These investments support BC Hydro meeting its forced outage factor service plan metric and include generator investments at Bridge River, G.M. Shrum, Revelstoke and Kootenay

Canal; and turbine overhaul projects at Mica, Seven Mile and G.M. Shrum. The Capital Plan also includes targeted investments at Strategic facilities, an increasing level of investment in physical security systems (non-MRS) and some provision for dismantling stations that are out of service.

The release dates of a number of projects have been deferred in the latest version of the Capital Plan. In some cases, such as with generator sustainment investments at G.M. Shrum (G5 and G9), this has been done considering the most recent condition information for those assets. In other cases, such as with cooling water piping system replacements at Mica and Seven Mile, investments were deferred to align with outages associated with other major projects (turbine overhauls in both of these cases).

Other investments have been deferred, where retained risks were determined to be manageable, to balance affordability with overall system risk and performance, these included reliability investments at select Strategic facilities such as Clowhom, Ladore and Puntledge. We continue to perform regular maintenance on these units, however, there is an increasing likelihood of unit failures prior to major re-investment which would primarily result in lost opportunity costs. Provisions for investing in out of service (OOS) facilities have also been limited within the period. Specifically, Elko (OOS 2014) has been deferred to while Alouette (OOS 2010) and Spillimacheen (OOS 2019) have been left outside of the period. To manage the regulatory/reputational risk associated with operating outside of our Water Licenses we have maintained open communication with the Comptroller of Water Rights and interested First Nations on BC Hydro's long-term plan to address these facilities.

Stations Asset Planning - Substations

The Substation portion of the Stations Asset Planning portfolio has an increased focus on sustainment investments, due to a moderation in the rate of load growth. The investment strategy focuses on the replacement of higher priority asset classes such as transformers, circuit breakers, and feeder section retrofits. A number of station rebuilds and upgrade projects are also planned that will facilitate the removal of end-of-life equipment. The portfolio includes the required funding to adhere to federal deadlines regarding the removal of PCB equipment that contains more than 50 parts per million (ppm) by the December 31, 2025 deadline and MRS Requirements.

There were some deferrals within the Substation portfolio, where retained risks were determined to be manageable, to balance affordability with overall system risk and performance. There were focused on the remaining major Sustain projects and programs without regulatory components, including the Port Alberni Refurbishment and the Patricia Upgrade. Reductions were also taken in recurring programs that do not have a regulatory compliance implications including: Instrument Transformer Replacements, Station Battery Bank Replacements, Station Insulator Replacements and 500 kV – 60 kV Disconnect Switch Replacements. As a result of these investment deferrals the portfolio anticipates an increased risk of end-of-life asset failures, and longer retention of end-of-life equipment with known limits of approach issues. These risks will be managed by normal station redundancy where possible but may require re-prioritization of the plan outside of the normal planning cycle. Risks associated with known limits of approach issues will continue to be managed through established operational work procedures.

Lines Asset Planning – Transmission

Investments under the Transmission portion of the Lines Asset Planning portfolio are focused on preserving the asset health and reliability of the bulk electric system, increasing capacity on the transmission system, meeting regulatory compliance requirements and mitigating the highest asset risks.

2.4 Annual 10 Year Capital Plan

Some deferral of investments was required, where retained risks were determined to be manageable, to balance affordability with overall system risk and performance. These deferrals included the dismantling associated with the 1X387AMX – Kitsault Transmission Line Hazard Mitigation project and the dismantling associated with the 2L146 (Horsey sub. to Goward sub.) - Cable Replacement project. Reductions were also taken in select recurring programs including ACSR2 Conductor Replacements, Spacer Damper Replacements, Access Program, and Disconnect Switch Replacements. Funding levels for high priority programs, such as wood pole replacements and metal structure civil and corrosion protection are in line with the amounts in the Previous Plan. Risks associated with these deferrals will be mitigated through monitoring of the health of the assets over time, through regular condition assessments and on-going maintenance and inspection activities. Where changes are observed, or risks emerge, decisions will be made with respect to the investment strategy and where necessary, short term operational changes.

Lines Asset Planning – Distribution

Investments under the Distribution portion of the Lines Asset Planning portfolio are focused on maintaining system safety and reliability, increasing capacity to meet customer demand, and grid modernization, which also supports system safety and reliability. The portfolio includes the required funding to adhere to federal deadlines regarding the removal of PCB equipment that contains more than 50 ppm by the December 31, 2025 deadline.

Reductions were taken in select sustainment programs and system improvement provisions, where retained risks were determined to be manageable, to balance affordability with overall system risk and performance. The programs reduced included Feeder Cable Replacements, Maintenance Access Hole Replacements, System Improvement projects to address New Feeders, and Voltage Conversions.

Decreasing voltage conversion and system expansion investment may lead to higher feeder and equipment loadings with a reduced ability to address existing overloaded feeders, which increased from 50 in F2019 to 163 in F2020 at current funding levels. Where changes are observed, or risks emerge, decisions will be made with respect to the investment strategy and where necessary, short term operational changes.

Lines Asset Planning – Protection & Control and Telecom

Investments under the P&C and Telecom portion of the Lines Asset Planning portfolio are focused on preserving the reliability of the telecom network and protection and control systems on the bulk electric system.

Some deferral of investments was required where retained risks were determined to be manageable, to balance affordability with overall system risk and performance, including the Jordan River – Communications System Upgrade project, which was deferred by two years, as well as reduction to the Leased Line Entrance Protection Replacement recurring sustainment program.

As a result of these investment deferrals, risks associated with ground potential rise (GPR) on high-voltage entrances of communication cables into substations that do not meet current BC Hydro design standards will remain on the system longer. Crews will continue to follow safe working procedures to mitigate some of the risk associated with working on or near this equipment. Preventative maintenance

[2] Aluminum core steel reinforced (ACSR) conductor.

inspections will continue, and critical emergent safety issues may be addressed by a corrective repair or through a minor capital project.

Technology

The capital plan funds Technology expenditures to enable and sustain business outcomes that help achieve our service plan objectives. This includes investments in cybersecurity and reliability compliance, data centre infrastructure, personal devices, networks, telephony, and a wide range of software platforms and applications. It also includes investments to enable and enhance business capabilities.

In addition to our service plan objectives, the key strategic drivers affecting the types of investments we make include government direction, regulation and compliance, desired business unit outcomes, utility industry direction, information technology (IT) asset health, IT market direction and IT trends. Specific drivers in the next five years include cybersecurity and regulatory compliance due to increasing cybersecurity threats and expanding NERC CIP and other MRS requirements; IT sustainment due to an aging IT asset base; modernization of IT supporting work planning, scheduling, and execution; and modernization and upgrade, or elimination of legacy IT systems that are out-of-support. Rapid advances in information technology allow our ongoing IT sustainment program to gradually introduce new capabilities such as data centre equipment modernization, mobility solutions, analytics and artificial intelligence (AI) to meet our business needs. Benefits include IT performance, capacity and mobility improvements; automation improvements for IT operations; and improved data-driven business decisions.

The Technology Capital Plan provides three years of investment level detail in the F2022 to F2024 period and portfolio level projections for the remaining years. In the F2022 to F2024 period, the Capital Plan includes appropriate investment to manage reliability compliance and cybersecurity, manage IT asset risk and sustain user productivity, and enhance existing business capabilities.

The Technology Capital Plan also includes funding in the F2022 to F2025 period for investment opportunity projects (value projects). These investments are to address key areas of IT obsolescence with the expectation that operating cost savings will offset capital amortization, ensuring that the investments are neutral to the rate impact of the Capital Plan. These include the Stations Work Management and Passport Decommissioning projects, and the enhanced capability portion of the Contact Centre Foundation project.

Funding declines sharply in F2025 to approximately 30% below expected requirements through F2031. This level of funding is expected to result in the following retained risks:

- Financial risk related to business application sustainment.
- Operational risk related to business enablement of safety, reliability and environment.
- Asset risk and productivity impacts due to delayed hardware and software platform improvements, delayed device replacements and reduced user provisioning.
- Cybersecurity risk due to delayed modernization of software platforms and applications.
- Business continuity risk due to delayed disaster recovery solutions

It is suggested that Technology capital funding in the F2025 to F2031 period be reviewed in the next planning cycle.

~~CONFIDENTIAL -~~ Discussion/Information

2.4 Annual 10 Year Capital Plan

Properties

The Properties capital plan continues to focus on mitigating Safety and Financial risks across the 100+ building portfolio, with emphasis on our larger and higher criticality facilities. Properties is continuing to invest in Building Development Projects (field building replacement projects) at the final high criticality large regional field office (Kamloops) and at the medium criticality facilities that are most in need of end-of-life asset replacement and operational upgrades. Properties will also continue to invest in upgrades to critical end-of-life building assets (e.g. roof replacements, HVAC upgrades) as well as a modest number of field building interior upgrades and construction/expansion of truck bay facilities to meet changing operational requirements. As the Long-Term Workplace Strategy has not yet been finalized, the Properties capital plan does not yet include any investment for a future hybrid work environment. In the short-term Properties' GHG specific investments will be managed opportunistically and then prioritized and included in future capital plans as appropriate.

In order to meet our capital additions targets, a number of Building Development projects continue to be delayed towards the back end of our 10-year plan or deferred beyond the 10-year plan. The annual spend on Building Improvement projects has also been reduced from historical levels. As a result of these investment deferrals and reductions, we anticipate continued deterioration of older buildings, with just over one third of building square footage being more than 40 years old, and asset deterioration or failures resulting in the need for additional repairs and maintenance expenditures as well as an impact on operations, safety, and employee satisfaction

These retained risks are being managed through the focus on larger and higher criticality facilities and systems where asset failure would have the greatest impact. Smaller and lower criticality facilities and systems will receive less investment, and assets will be allowed to deteriorate further than they have historically.

Fleet Services

The Fleet Services capital program is a continuous sustainment program to replenish fleet assets and support safe, efficient operations. Fleet assets are prioritized for replacement based on risk scores that measure variables such as maintenance costs, reliability, and condition of the asset. Under the current plan, approximately 731 end-of-life assets will be replaced by the end of F2026. This plan does not include capital to replace all fleet assets that are forecast to reach end-of-life. End-of-life assets that are deferred based on risk will grow from 102 units in F2021, to 361 units at F2026. The estimated replacement value of total deferred fleet assets will reach $39.3M by F2026.

BC Hydro is required to respond to emergency outages and operate in remote areas of the province. Most vehicle categories have limited alternative fuel products (i.e. electric) in the marketplace and/or are new to market. Another limitation is the small, but growing, volume of charging infrastructure across the province. Our near-term strategy to address greenhouse gas emissions includes small scale pilots of electric vehicle technology to evaluate viability. We anticipate increased adoption of electric vehicles in some light vehicle and equipment categories towards the end of the period.

We are currently funded to maintain the reliability of fleet assets, but forecast a need for escalated funding, starting in F2025. At the current funding levels, there is a risk that the Fleet Portfolio will see an increase in repair costs or an increase in vehicle downtime.

To manage these risks, Fleet is implementing Telematics[3] to assist in GHG emissions reduction while optimizing fleet asset life cycles, and is updating vehicle/financial policies such as: vehicle assignment criteria, re-allocation of low-utilization assets, and fleet standardization.

Resources and Execution of the Plan

This Capital Plan has been developed in consultation with Project Delivery and Program and Contract Management. Resource demand modelling was completed on critical Operations and Engineering resources. The resource modelling identified potential overloading of CPC technologists in the near term. In F2022 and F2023, the demand for these resources is largely driven by MRS Compliance initiatives and projects in Implementation. These types of non-discretionary investments offer minimal opportunity to reduce or defer as part of the enterprise wide prioritization framework for long term capital planning. This resource, as well as others impacted by COVID-19 protocols and MRS, may continue to present a delivery risk to the plan in the next one to two-year period. These resource risks will need to be monitored through the 2 - 12 month resource modelling, issues raised through the escalation process and adjustments made through this more detailed work planning process.

From a broader resource perspective, we have limited data to model the increasing demands on resources to complete capital and maintenance work in adherence to compliance standards. As this information evolves and the resource models account for these increased demands, it is possible additional Operations resource risks to the Capital Plan may be identified.

Telecom Engineering resource modelling also indicated a potential resource risk. The release of several projects in this portfolio have been deferred to ensure that resources can focus on supporting MRS compliance initiatives and higher priority projects.

Modelling and associated mitigation analysis indicate that other critical Operations and Engineering resources are balanced or can be balanced using resource augmentation and contracting strategies.

Overall, in the F2023-F2027 period, this Capital Plan includes funding for investments delivered by Program and Contract Management (PCM) that is a modest increase over the amounts delivered in F21. Expenditures at this level are considered low risk to the delivery of our small capital and recurring work programs.

As discussed above, the increasing capital expenditures profile is driven by Project Delivery's forecast for projects that are currently active and that will be entering the Implementation phase in the coming years. Modelling on associated resources such as senior level project managers and construction managers indicates a potential risk that is resolvable with appropriate resource planning strategies and does not require demand side adjustments by Integrated Planning at this time.

[3] Telematics: the installation of technology within Fleet vehicles to allow for the collection of vehicle data for analysis of key metrics such as good idling vs bad idling, hard/extreme breaking/acceleration, utilization and real time vehicle diagnostics.

BC Hydro
Power smart

~~CONFIDENTIAL -~~ Discussion/Information

2.4 Annual 10 Year Capital Plan

Appendix A: Capital Expenditures & Additions F2022 – F2031

Current 10 Year Capital Expenditure Forecast

ESTIMATED CAPITAL EXPENDITURES *	Forecast F22	F23	F24	F25	F26	Plan F27	F28	F29	F30	F31	F22-F31 10 Yr Total	F22-F31 10 Yr Avg.
Sustaining												
Generation	376.6	300.9	311.0	500.4	564.0	628.9	734.1	752.2	756.2	771.0	5,695.2	569.5
Transmission	349.4	381.9	392.1	388.4	481.2	402.7	341.3	239.3	257.2	257.5	3,491.1	349.1
Distribution	217.7	193.8	190.9	182.4	190.2	217.8	241.2	241.1	229.6	227.5	2,132.3	213.2
Support Services - Technology	107.1	109.4	88.2	86.6	55.9	58.9	67.1	66.4	52.6	50.2	742.1	74.2
Support Services - Properties	51.5	83.4	81.7	92.3	78.4	53.8	42.9	54.9	38.9	42.0	619.7	62.0
Support Services - Other & Subsidiaries	72.2	91.8	88.0	69.7	69.0	74.3	74.8	75.6	84.7	96.7	796.8	79.7
Subtotal - Sustaining	1,174.6	1,161.1	1,151.9	1,319.8	1,438.6	1,436.4	1,501.3	1,429.5	1,419.2	1,444.8	13,477.1	1,347.7
Growth												
Generation	0.0	-	-	-	6.9	10.1	3.6	4.4	12.9	18.1	56.0	5.6
Generation - Site C Project	3,129.1	2,685.0	1,450.6	858.7	310.1	2.9	-	-	-	-	8,436.4	843.6
Transmission	79.7	93.2	137.2	122.2	107.8	253.4	307.3	299.4	295.2	262.6	1,958.0	195.8
Distribution	321.1	326.6	331.5	333.7	321.6	310.8	315.9	338.2	345.8	356.1	3,301.3	330.1
Support Services - Other & Subsidiaries	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal - Growth	3,529.9	3,104.7	1,919.4	1,314.6	746.4	577.2	626.8	641.9	653.9	636.8	13,751.7	1,375.2
Total before Contribution In Aid (CIA)	4,704.5	4,265.8	3,071.2	2,634.4	2,185.0	2,013.6	2,128.2	2,071.4	2,073.0	2,081.6	27,228.7	2,722.9
Transmission - Sustaining	(6.8)	(6.5)	(5.5)	(5.7)	(5.8)	(5.9)	(8.6)	(6.1)	(6.2)	(6.4)	(63.4)	(6.3)
Transmission - Growth	(2.2)	(23.2)	(21.1)	(10.6)	(11.2)	(11.4)	(8.7)	(11.8)	(12.2)	(4.8)	(117.1)	(11.7)
Distribution - Sustaining	(0.8)	(2.1)	(2.1)	(2.2)	(2.2)	(2.2)	(2.3)	(2.3)	(2.4)	(2.4)	(21.1)	(2.1)
Distribution - Growth	(149.0)	(156.2)	(157.3)	(159.0)	(161.5)	(164.8)	(167.7)	(171.7)	(175.2)	(178.7)	(1,641.1)	(164.1)
CIA Total	(158.7)	(188.1)	(186.1)	(177.4)	(180.7)	(184.3)	(187.2)	(192.0)	(196.0)	(192.3)	(1,842.7)	(184.3)
Total ($M)	**4,545.8**	**4,077.8**	**2,885.2**	**2,456.9**	**2,004.3**	**1,829.3**	**1,940.9**	**1,879.4**	**1,877.0**	**1,889.3**	**25,386.0**	**2,538.6**
less Site C	1,416.7	1,392.8	1,434.6	1,598.3	1,694.2	1,826.4	1,940.9	1,879.4	1,877.0	1,889.3	16,949.6	1,695.0

ESTIMATED CAPITAL ADDITIONS *	Forecast F22	F23	F24	F25	F26	Plan F27	F28	F29	F30	F31	F22-F31 10 Yr Total	F22-F31 10 Yr Avg.
Generation	393.2	443.2	223.2	249.3	330.1	605.2	960.6	567.2	631.5	883.1	5,286.6	528.7
Generation - Site C Clean Energy	-	-	-	14,410.2	518.3	2.9	-	-	-	-	14,931.4	1,493.1
Transmission	489.8	257.7	436.0	542.4	603.8	346.2	881.7	558.8	445.5	731.8	5,293.7	529.4
Distribution	626.6	542.6	553.7	531.1	517.5	523.2	549.8	575.2	576.5	582.4	5,578.7	557.9
Support Services - Technology	79.3	130.6	119.5	78.6	50.7	73.4	67.7	68.5	52.6	50.2	771.0	77.1
Support Services - Properties	38.5	32.7	65.9	25.7	182.2	94.2	18.9	60.6	52.4	35.9	607.1	60.7
Support Services - Other & Subsidiaries	74.8	82.0	102.8	68.9	71.3	72.7	70.1	69.3	71.1	94.2	777.1	77.7
Total before CIA	1,702.2	1,488.7	1,501.0	15,906.3	2,273.9	1,718.0	2,548.8	1,899.6	1,829.6	2,377.5	33,245.6	3,324.6
CIA	(213.3)	(170.1)	(176.6)	(209.4)	(181.5)	(184.8)	(187.5)	(190.6)	(195.5)	(193.2)	(1,902.4)	(190.2)
Total ($M)	**1,489.0**	**1,318.6**	**1,324.4**	**15,696.8**	**2,092.4**	**1,533.2**	**2,361.3**	**1,709.0**	**1,634.1**	**2,184.3**	**31,343.1**	**3,134.3**
less Site C	1,489.0	1,318.6	1,324.4	1,286.7	1,574.1	1,530.2	2,361.3	1,709.0	1,634.1	2,184.3	16,411.7	1,641.2

* 'Capital Expenditures' are recorded when the costs are incurred. 'Capital Additions' refer to when the related asset is placed into service. Certain costs impacting BC Hydro's revenue requirements, such as amortization, return-on-equity, and finance charges, are not recorded until the related asset is placed into service.

~~CONFIDENTIAL~~ ~~-~~ Discussion/Information

2.4 Annual 10 Year Capital Plan

Appendix B: Projects > $50M – F2022-F2031[4]

Asset Owner	Project	Type	Phase	Forecasted ISD	Authorized Amount / Engineering Estimate / Latest Forecast ($M)
Dam Safety	Alouette Improve Headworks & Surge Tower Seismic Stability	Sustaining	Identification	TBD	TBD
Dam Safety	Cheakamus - Dam Improvements	Sustaining	Future	TBD	TBD
Dam Safety	John Hart Dam Seismic Upgrade	Sustaining	Definition	F2030	$741 - $434
Dam Safety	Ladore Spillway Seismic Upgrade	Sustaining	Definition	F2028	$265 - $158
Dam Safety	Lajoie - Dam Improvements	Sustaining	Identification	TBD	TBD
Dam Safety	Mica - Discharge Facilities Seismic and Reliability Upgrades	Sustaining	Identification	TBD	TBD
Dam Safety	Peace Canyon-Spillway Gates Reliability Improvements	Sustaining	Future	TBD	TBD
Dam Safety	Revelstoke - Discharge Gate Systems Reliability Improvements	Sustaining	Future	TBD	TBD
Dam Safety	Strathcona Upgrade Discharge	Sustaining	Definition	F2027	$332 - $200
Generation	Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior	Sustaining	Identification	TBD	TBD
Generation	Bridge River 1 Replace Units 1-4 Generators / Governors	Sustaining	Definition	F2031	$343 - $208
Generation	Bridge River 2 Upgrade Units 5 and 6	Sustaining	In-Service	F2020	$74
Generation	Bridge River 2 Upgrade Units 7 and 8	Sustaining	Implementation	F2022	$85
Generation	Cheakamus Units 1 and 2 Generator Replacement	Sustaining	In-Service	F2020	$62
Generation	Clowhom - Unit Upgrade	Sustaining	Deferred	TBD	TBD
Generation	G.M. Shrum - U9 - U10 Turbine Overhaul	Sustaining	Future	TBD	TBD
Generation	G.M. Shrum G1 to 10 Control System Upgrade	Sustaining	Implementation	F2023	$75
Generation	JHT - Generating Station Replacement	Sustaining	In-Service	F2019	$973
Generation	Kootenay Canal - U1 - U4 Generators Refurbishment	Sustaining	Identification	TBD	TBD
Generation	Kootenay Canal Modernize Controls	Sustaining	Identification	TBD	TBD
Generation	LaJoie - Unit Upgrade	Sustaining	Future	TBD	TBD
Generation	Mica - U1 - U2 Turbine Overhaul	Sustaining	Future	TBD	TBD
Generation	Mica - U1 - U4 Circuit Breaker and Iso-phase Bus Replacement	Sustaining	Identification	TBD	TBD
Generation	Mica Modernize Controls	Sustaining	Implementation	F2024	$56
Generation	Mica Replace Units 1 to 4 Generator Transformers	Sustaining	Implementation	F2023	$80
Generation	Revelstoke - U1 - U4 Transformer Replacement	Sustaining	Future	TBD	TBD
Generation	Revelstoke - U1 - U4 Stator Replacement	Sustaining	Identification	TBD	TBD
Generation	Revelstoke Install Unit 6	Growth	Deferred	TBD	TBD
Generation	Seton - Upgrade Unit	Sustaining	Identification	TBD	TBD
Generation	Seven Mile - U1 - U3 Turbine Upgrade	Sustaining	Future	TBD	TBD
Generation	Wahleach Refurbish Generator	Sustaining	Implementation	F2023	$51
Properties	Kamloops Field Building Redevelopment	Sustaining	Identification	F2027	TBD
Substations	Capilano Substation Upgrade	Growth	Implementation	F2025	$87
Substations	DVES: West End Strategic Property Purchase	Growth	Implementation	F2022	$81
Substations	East Vancouver - Substation Construction	Growth	Future	TBD	TBD
Substations	Horne Payne Substation Upgrade	Growth	In-Service	F2019	$72

[4] Project phase and financial information provided in this table are as of January 1, 2021, the currency date of the F2022-F2031 Capital Plan.

~~CONFIDENTIAL~~ - Discussion/Information

2.4 Annual 10 Year Capital Plan

Asset Owner	Project	Type	Phase	Forecasted ISD	Authorized Amount / Engineering Estimate / Latest Forecast ($M)
Substations	Mainwaring Station Upgrade	Sustaining	Identification	TBD	TBD
Substations	Maple Ridge - Feeder Section 60 Series Refurbishment	Sustaining	Future	TBD	TBD
Substations	Mount Lehman Substation Upgrade	Growth	Implementation	F2023	$59
Substations	Natal Sub - NTL 60-138 kV Rebuild	Sustaining	Definition	F2025	$151 - $49
Substations	Newell Substation Upgrade	Sustaining	Identification	TBD	TBD
Substations	Peace to Kelly Lake - Stations Sustainment	Sustaining	Definition	F2027	$309 - $175
Substations	West End - Substation Construction and System Reinforcement	Growth	Identification	TBD	TBD
Substations	Sperling substation (SPG) metalclad switchgear	Sustaining	Implementation	F2025	$54
Technology	Supply Chain Applications	Sustaining	In-Service	F2021	$69
Transmission	Customer IPID - 901943	Growth	Future	TBD	TBD
Transmission	MIN to LNG Canada Interconnection	Growth	Implementation	F2022	$82
Transmission	Customer IPID - 901581	Growth	Identification	TBD	TBD
Transmission	UBC Load Increase Stage 2	Growth	In-Service	F2021	$55
Transmission	2L146 - Cable Replacement	Sustaining	Identification	TBD	TBD
Transmission	5L063 Telkwa Relocation	Sustaining	Implementation	F2024	$66
Transmission	Bridge River Transmission Project	Growth	Identification	TBD	TBD
Transmission	Fort St. John and Taylor Electric Supply	Growth	In-Service	F2021	$52
Transmission	Lower Mainland - Capacitive and Reactive Power Reinforcement	Growth	Identification	TBD	TBD
Transmission	North Montney Region - Electrification	Growth	Identification	TBD	TBD
Transmission	Peace Region Electric Supply (PRES)	Growth	Implementation	F2022	$285
Transmission	Prince George to Terrace Capacitors Project	Growth	Identification	TBD	TBD
Transmission	South Fraser Transmission Relocation Project	Sustaining	Deferred	TBD	TBD
Transmission	System Wide – Bulk Electric System Telecom Equipment Replacement	Sustaining	Identification	TBD	TBD
Transmission	Vancouver Island Radio System	Sustaining	Implementation	F2024	$32
Transmission	Various Sites - LED Street Light Conversion	Sustaining	Implementation	F2024	$75
Transmission	West Kelowna Transmission and Westbank Upgrade Projects	Growth	Identification	TBD	TBD

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix I

Capital Expenditures > $5 million

PUBLIC

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Generation			
Hydroelectric			
Growth			
N/A			
Redevelopment / Rehabilitation			
N/A			
Dam Safety			
Bridge River 2 - Strip and Recoat Penstock 2 Interior	1	Page 7	Pages 11 and 5
Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)	2	Page 15	Pages 14 and 5
Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment	3	Page 48	Page 31
Revelstoke Replace Downie Slide Instrumentation	4	N/A	Page 39
Comox - Puntledge Flow Control Improvements	5	Page 17	Page 37
John Hart Dam Seismic Upgrade	6	Page 32	Pages 3 and 22
Ladore Spillway Seismic Upgrade	7	Page 44	Pages 3 and 29
Mica - Intake Gantry Crane Refurbishment	8	N/A	Page 33
Strathcona Upgrade Discharge	9	Page 78	Pages 3 and 47
W.A.C. Bennett Dam Seal Low Level Outlets	10	Page 89	Page 18
Alouette - Environmental Flow Discharge Upgrade and LLO Sealing	11	N/A	Page 7
Alouette Improve Headworks & Surge Tower Seismic Stability	12	Page 1	Page 7
Ash River Extend Life of Steel Penstock	13	Page 3	Pages 9 and 5
Bridge River 1 - Improve Slope Drainage	14	N/A	Page 11
Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior	15	Page 7	Pages 11 and 5
GMS – Install Further Instrumentation for Monitoring Embankment Condition	16	N/A	Page 18
Hugh Keenleyside - Spillway and Low Level Outlets Concrete Upgrade	17	Page 30	Page 20

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Hugh Keenleyside - Fire Protection System Upgrade	18	N/A	Page 18
La Joie - Dam Improvements	19	Page 40	Pages 27 and 1
Mica - Discharge Facilities Seismic and Reliability Upgrades	20	Page 55	Page 33
Terzaghi - Spillway Chute Access Improvement	21	N/A	Page 11
Various Sites - Reservoir Booms Replacement - F2020	22	Page 83	N/A
W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates	23	Page 86	Page 18
Bridge River 1 - Penstock Concrete Foundation Refurbishment	24	Page 5	Page 11
Cheakamus - Dam Improvements	25	Page 13	Page 14
G.M. Shrum - Intake Operating Gate and Intake Maintenance Gate Refurbishment	26	Page 27	Page 18
G.M. Shrum - Intake Operating Gate Hydraulic Upgrade	27	Page 27	Page 18
Hugh Keenleyside - Cranes Upgrade	28	N/A	Page 20
Kootenay Canal - Canal Concrete Liner Joints Upgrade	29	Page 35	Page 25
Lake Buntzen 1 - Penstock Interior Restoration	30	Page 50	Page 31
Mica - Little Chief Inclinometers Installation	31	N/A	Page 33
Ruskin - Left Abutment Slope Sinkhole Remediation	32	N/A	N/A
Seton - Canal Flow Control Structure Upgrade	33	Page 71	Pages 41 and 1
Sugar Lake - Dam Abutments Upgrade	34	N/A	Page 45
Terzaghi - Dam Instrumentation Upgrade	35	N/A	Page 11
Terzaghi - Low Level Discharge Reliability Improvement	36	Page 81	Pages 11 and 1
Various Sites - Probabilistic Seismic Hazard Model Update	37	N/A	N/A
Various Sites - Spillway Gate Standby Power Improvements	38	Page 85	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Sustaining - Other			
Cheakamus Replace Units 1 and 2 Turbine Inlet Valves	39	N/A	Page 14
G.M. Shrum G1 to 10 Control System Upgrade	40	Page 20	Page 18
G.M. Shrum Upgrade HVAC System	41	Page 22	Page 18
Hugh Keenleyside Recoat Navlock Gates	42	N/A	Page 20
Hugh Keenleyside Replace Service Water Piping	43	N/A	Page 20
Jordan - Upgrade Governor & PRV Controls	44	N/A	Page 23
Mica - Reactor 5RX3 Replacement	45	Page 52	Page 33
Mica Modernize Controls	46	Page 57	Page 33
Mica Replace Units 1 to 4 Generator Transformers	47	Page 59	Page 33
Mica Upgrade 600V Circuit Breakers	48	Page 63	Page 33
Mica Upgrade HVAC System	49	Page 65	Page 33
Peace Canyon - 600V Circuit Breaker Upgrades	50	N/A	Page 35
Puntledge Recoat Interior and Exterior of Steel Penstock	51	Page 67	Pages 37 and 5
Revelstoke Replace Fire Alarm System	52	N/A	Page 39
Seven Mile - Replace T1 Transformer	53	N/A	Page 43
Seven Mile Upgrade Powerhouse Crane Controls	54	N/A	Page 43
Various - Water License Renewal	55	N/A	N/A
Wahleach Recoat Penstock (Interior and Exterior)	56	N/A	Pages 49 and 5
Wahleach Refurbish Generator	57	Page 91	Page 49
Waneta U3 Life Extension	58	Page 93	N/A
Bridge River 1 Replace Units 1-4 Generators / Governors	59	Page 9	Page 11
Various Sites - Cutler Hammer Exciters Upgrade	60	N/A	Page 16
Whatshan - Governor Replacement	61	N/A	Page 51
Ash River - Upgrade Communication Systems	62	N/A	Page 9
GMS - Unwatering System Refurbishment	63	Page 29	Page 18
Kootenay Canal - U1 - U4 Generators Refurbishment	64	Page 37	Page 25
Kootenay Canal Modernize Controls	65	Page 38	Page 25
Lake Buntzen 1 - Generator Replacement	66	Page 46	Page 31
LDR - Upgrade Communication Systems	67	N/A	Page 29

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Mica - U1 - U4 Circuit Breaker and Iso-phase Bus Replacement	68	Page 54	Page 33
Peace Canyon - U1 - U4 Exciter Replacement	69	N/A	Page 35
Revelstoke - U1 - U4 Stator Replacement	70	Page 69	Page 43
Seton - Upgrade Unit	71	Page 73	Page 41
Various Facilities Replace Water Level Gauges	72	N/A	N/A
Ash River - Generator Replacement	73	N/A	Page 9
Bridge River 2 - Transformer Replacement	74	N/A	N/A
G.M. Shrum - Pauwels Transformer Life Extension	75	N/A	Page 18
G.M. Shrum - Physical Security Upgrade - Phase I	76	Page 24	Page 18
G.M. Shrum - U5 Generator Refurbishment	77	Page 25	Page 18
G.M. Shrum - U6 Generator Refurbishment	78	Page 26	Page 18
Kootenay Canal - Fire Detection and Alarm System Replacement	79	N/A	Page 25
Ladore - Unit Transformer Upgrade	80	N/A	Page 29
La Joie - Governor Pressure Regulating Valve Replacement	81	Page 42	Page 27
Mica - Crash-rated Gate Replacement	82	N/A	N/A
Mica - Nagle Creek Crossing Infrastructure Refurbishment	83	N/A	Page 33
Mica - U1 - U2 Turbine Overhaul	84	Page 61	Page 33
Peace Canyon - High and Low Pressure Piping Replacement	85	N/A	Page 35
Peace Canyon - Powerhouse, Intake and Tailrace Crane Upgrades	86	N/A	Page 35
Revelstoke - Intake and Tailrace Gantry Crane Upgrades	87	N/A	Page 39
Seven Mile - U1 - U3 Turbine Upgrade	88	Page 76	Page 43
Seven Mile - U1 - U4 Controls Upgrade	89	Page 75	Page 43
Various Sites - PCB Lighting Remediation (F2022-F2024)	90	N/A	N/A
Diesel			
N/A			

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Thermal			
Burrard - Modify for Post Generation Operations	91	N/A	Page 13
Fort Nelson - U2 Steam Turbine Overhaul	92	N/A	Page 17
Transmission			
Growth Capital Expenditures			
Regional System Reinforcement			
Bridge River Transmission Project	1	Page 104	Page 75
North Montney Region - Electrification	2	Page 136	Page 95
West Kelowna Transmission and Westbank Upgrade Projects	3	Page 162	Page 96
West End - Substation Construction and System Reinforcement	4	Page 160	Page 77
Peace to Kelly Lake - Remedial Action Scheme Upgrade	5	N/A	N/A
East Vancouver - Substation Construction	6	Page 110	Page 77
Sunshine Coast - Transmission Reinforcement	7	Page 151	N/A
Bulk System Reinforcements			
Cranbrook 5L94 - Line Reactor Replacement	8	N/A	N/A
Lower Mainland - Capacitive and Reactive Power Reinforcement	9	Page 123	Page 76
Prince George to Terrace Capacitors Project	10	Page 146	N/A
Station Expansion & Modification			
Capilano Substation Upgrade	11	Page 106	Page 80
Clayburn Substation Upgrade	12	Page 108	Page 53
Mount Lehman Substation Upgrade	13	Page 128	Page 53
Horne Payne - Feeder Section Addition	14	Page 114	Page 87
Generator Interconnections			
N/A			
Transmission Load Interconnections			
Customer IPID - 901580	15	N/A	N/A
Customer IPID - 901573	16	N/A	N/A
Customer IPID - 901851	17	N/A	N/A
Customer IPID - 901581	18	N/A	N/A
Customer IPID - 901940	19	N/A	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Customer IPID - 902121	20	N/A	N/A
Customer IPID - 901943	21	N/A	N/A
Customer IPID - 901938	22	N/A	N/A
Sustaining Capital Expenditures			
Circuit Breakers			
SPG Metalclad Switchgear Replacement	23	Page 149	Page 92
Kimberley to Marysville - Substation Relocation	24	Page 119	Page 60
Pemberton - Substation Rebuild	25	N/A	Page 60
Maple Ridge - Feeder Section 60 Series Refurbishment	26	Page 127	Page 60
Other Power Equipment			
American Creek - Capacitor Protection Control Upgrade	27	N/A	Page 56
Barnard 50/60 Feeder Section Replacement	28	Page 100	Page 73
Hundred Mile House T1/T2 EOL Replacement	29	N/A	Page 69
Jordan River - Switchyard Upgrade	30	Page 115	Page 69
SC Excitation Systems Upgrade - VIT/KLY	31	N/A	Page 68
Natal Sub - NTL 60-138 kV Rebuild	32	Page 130	Page 85
Sandspit Substation Replacement	33	N/A	Page 97
Ah-sin-heek - Substation Replacement	34	N/A	Page 97
Bridge River - T4 Transformer Replacement	35	Page 102	Page 69
Kennedy - 5CX1 Controls Replacement (Emergency)	36	N/A	N/A
Oldfield - Substation Feeder Section Upgrade	37	N/A	Page 89
Peace to Kelly Lake - Stations Sustainment	38	Page 140	Pages 59, 66 and 67
VIT & KLY Hydrogen Gas Sys - Safety Upgrade	39	N/A	Page 68
KI1 60Kv Renovation, 4Kv Decommission & Control Room	40	Page 117	Page 82
Mainwaring Station Upgrade	41	Page 125	Page 84
Newell Substation Upgrade	42	Page 134	Page 86
Patricia - Substation Upgrade	43	Page 138	Page 91
Peace Region to Kelly Lake - Reactor Replacement (Phase 2)	44	Page 142	Page 67
Kelly Lake - Reactor Installation	45	N/A	Page 68

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Norgate - Substation Bypass	46	N/A	Page 80
Peace Region to Kelly Lake - Reactor Replacement (Phase 3)	47	Page 142	Page 67
Peace Region to Kelly Lake - Reactor Replacement (Phase 4)	48	Page 142	Page 67
Telegraph Creek - Substation Replacement	49	N/A	Page 97
Protection and Control			
GMS Substation - Control Systems Upgrade	50	N/A	Page 56
NERC CIP V5 Compliance at Medium Impact T&D Stations	51	Page 132	Page 56
Control PLC984 and RTU Replacement (WSN)	52	N/A	Page 56
Various Sites - NERC CIP-003v7 Implementation	53	Page 156	Page 56
Stations Auxiliary Equipment			
Joseph Creek (JOE) Substation Upgrade	54	N/A	Page 97
Canal Flats - Substation Wood Pole Replacement	55	N/A	Page 97
Skookumchuck - Substation Wood Pole Replacement	56	N/A	Page 97
Cathedral Square - Substation HVAC Upgrade	57	N/A	Page 59
Lumby #2 - Substation Wood Pole Replacement	58	N/A	Page 97
Port Alberni - Substation Refurbishment	59	Page 144	Page 59
Prevost - Substation Control Building Upgrade	60	N/A	Page 59
Woss - Substation Wood Pole Replacement	61	N/A	Page 97
Stations Risk Mitigation			
Oil Spill Containment - F17/F18 (ALZ / MDN)	62	N/A	Page 64
Stations Seismic Upgrade -F16/17 (9 Stations)	63	N/A	N/A
Project IPID - 900766: Jeune Landing - Substation Acquisition and Upgrade	64	N/A	N/A
Telecommunications			
Vancouver Island Radio System	65	Page 154	Page 71
Various Sites - Mountain Top 1603 Replacement	66	N/A	Page 71
System Wide – Bulk Electric System Telecom Equipment Replacement	67	Page 152	Page 71
Various Sites - Telecom Analog Private Line Replacement	68	N/A	Page 55

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Fraser Valley - Telecom System Reliability Upgrade	69	N/A	Page 79
Various Sites - MPLS Core Router Upgrade	70	N/A	Page 71
Various Sites – Telecom Transport Network Resiliency Enhancement	71	Page 158	Page 93
Cable Sustainment			
2L146 - Cable Replacement	72	Page 96	Page 63
Coquitlam - 2L51 Partial Replacement	73	N/A	Page 63
Gulf Islands - Transmission Reinforcement	74	Page 112	Page 63
South Fraser Transmission Relocation Project	75	Page 148	N/A
O/H Lines Life Extension			
5L063 Telkwa Relocation	76	Page 98	N/A
Long Span Crossing Refurbishment - F17/F18 (1L37)	77	Page 121	Page 58
O/H Lines Risk Mitigation			
1X387AMX – Kitsault Transmission Line Hazard Mitigation	78	N/A	N/A
2L003 and 2L049 – Transmission Line Crossing Seismic Upgrade (Second Narrows)	79	Page 95	Page 74
ROW Sustainment			
N/A			
Third Party Requested Transmission Line Relocations			
Customer IPID - 901563	80	N/A	N/A
Customer IPID - 901807	81	N/A	N/A
Distribution			
Growth Capital Expenditures			
Customer Driven			
Customer IPID DY-1545	1	N/A	N/A
Customer IPID DY-0347	2	N/A	N/A
Customer IPID 901955	3	N/A	N/A
Customer IPID 902127	4	N/A	N/A
Customer IPID 902128	5	N/A	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
System Expansion and Improvement			
LOH 12F56, 12F62 Voltage Conversion Preparation (LM-BBY-082)	6	N/A	N/A
Mount Lehman New Feeder to Offload Balfour, Mount Lehman and Gloucester Feeders (FV-ABT-042)	7	N/A	N/A
Two new CBN Feeders to Offload SMW (LM-FVE-606)	8	N/A	N/A
Glenmore Voltage Conversion (LM-NSC-088)	9	N/A	N/A
Norgate - Offload NOR loads to NVR feeders (LM-NSH-074)	10	N/A	N/A
North Vancouver - Offload NVR loads to LYN new feeders (LM-NSH-075)	11	N/A	N/A
Oldfield (OFD) Voltage Conversion 12 to 25kV (NI-NEW-273)	12	N/A	N/A
Three Fleetwood feeders to offload McLellan (FV-FVW-723)	13	N/A	N/A
Three new MLE Feeders to offload CBN (LM-FVE-607)	14	N/A	N/A
Downtown Vancouver - Voltage Conversion Preparation for Customer Vaults (LM-VAN-210)	15	N/A	N/A
Fleetwood - Distribution Feeder Ductbank and Feeder Installation (FV-FVW-023)	16	N/A	N/A
Fleetwood - Distribution Feeder Ductbank and Feeder Installation (FV-FVW-805)	17	N/A	N/A
Langley - MLN 25F32 and MLN 25F33 Offload (FV-FVW-741)	18	N/A	N/A
Tofino - New LBH 25F54 Feeder Installation To Offload LBH 25F52 (VI-PAL-010)	19	N/A	N/A
Vancouver Island - Saltspring 25F61 Cable Extension to North Pender Island (VI-GUL-005)	20	Page 170	N/A
Sustaining Capital Expenditures			
System Expansion and Improvement			
Downtown Vancouver - Underground Murrin Feeders to Eliminate H-Frames in Gastown	21	Page 165	N/A
H-Frame Elimination - Chinatown	22	Page 167	N/A
Mission - Feeder 25F51 Tie (FV-ABT-039)	23	N/A	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
100 Mile House - Relocate Sections of Transmission along Hendrix Road (SI-HMH-002)	24	N/A	N/A
Gwillim Microwave - Power Supply Upgrade	25	N/A	N/A
Asset Replacement			
Various Sites - LED Street Light Conversion	26	Page 172	Page 99
Electric Vehicle Charging Infrastructure			
N/A			
Beautification			
N/A			
Technology			
Manage Compliance and Security			
Projects Over $2 million			
NERC CIP-13	1	N/A	N/A
MRS Compliance System Project - SigmaFlow	2	N/A	N/A
Time Based Rates	3	N/A	N/A
Privileged Access Management	4	N/A	N/A
Splunk Subscription License Acquisition	5	N/A	N/A
Cisco Enterprise License Acquisition	6	N/A	N/A
Corporate Firewalls Refresh	7	N/A	N/A
Manage Risk and Sustain Productivity			
Projects Over $2 million			
SAP S/4HANA Upgrade	8	Page 185	N/A
Human Capital Management (HCM) Foundation	9	N/A	N/A
SAP Business Warehouse on HANA Migration	10	N/A	N/A
Contact Centre Technology Foundation Refresh	11	Page 176	N/A
GE Smallworld GIS Platform Upgrade	12	N/A	N/A
SAP Customer Front End Replacement	13	N/A	N/A
Openway Migration	14	N/A	N/A
Energy Management System (EMS) 3.x Upgrade	15	Page 179	N/A
Primary Data Centre Network Refresh	16	N/A	N/A
Backup Data Centre Network Refresh	17	N/A	N/A
Operations Data Centre Network Refresh	18	N/A	N/A
Windows Server Upgrade	19	N/A	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Data Centre Backup	20	Page 184	N/A
Data Centre Backup Sustainment	21	N/A	N/A
Data Centre Backup Sustainment	22	N/A	N/A
Physical Security Network Transition	23	N/A	N/A
EAS Greenplum Hardware Upgrade	24	N/A	N/A
Corporate Telephony Replacement	25	Page 183	N/A
Corporate Telephony Replacement	26	Page 183	N/A
Regional site infrastructure refresh	27	N/A	N/A
Meter Data Management System Upgrade	28	N/A	N/A
Projects and Programs less than $2 million			
N/A			
Enhance Business Capability			
Projects over $2 million			
Dam Safety Information System (DSIS)	29	N/A	N/A
Vehicle and Equipment Telemetry	30	N/A	N/A
Advanced Distribution Management System (ADMS)	31	Page 174	N/A
Stations Work Management	32	Page 186	N/A
Distribution Design Modernization	33	Page 178	N/A
Programs over $2 million (Recurring Capital)			
N/A			
Projects and Programs less than $2 million			
N/A			
Properties			
Chilliwack Field Building Redevelopment	1	Page 187	N/A
Materials Classification Facility Building Redevelopment	2	Page 189	N/A
Kamloops Field Building Redevelopment	3	Page 191	N/A
North Vancouver Field Building Redevelopment	4	Page 193	N/A
Campbell River II Field Building Redevelopment	5	Page 195	N/A
Dunsmuir Roof & 18th Floor HVAC Upgrade	6	N/A	N/A
Duncan Field Building Redevelopment	7	Page 197	N/A
Mica Staff Accommodations Building Redevelopment	8	N/A	N/A
Prince Rupert Field Building Redevelopment	9	N/A	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Edmonds Operations Centre Truck Bay Upgrade	10	N/A	N/A
Surrey LMS Truck Bay Upgrade	11	N/A	N/A
Queen Charlotte City Field Building Redevelopment	12	N/A	N/A
Cranbrook Field Building Redevelopment	13	Page 199	N/A
Fort St. John Field Building Redevelopment	14	N/A	N/A
Business Support Other			
Other Technology			
Mobile Radio Optimization - LM	1	N/A	N/A
Fleet/Vehicles			
Fleet/Vehicles	2	N/A	N/A
Business Support - Other			
Material Management - Oil Management Operating Infrastructure	3	N/A	N/A
Site C Project			
Site C	1	Page 201	N/A

Appendix I - F2023-F2025 RRA - Generation
Projects greater than $5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F23-F25) as at January 1, 2021 (1), (2)
$ Million

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F21	Capital Addition Forecast F22	Capital Addition Forecast F23	Capital Addition Forecast F24	Capital Addition Forecast F25	Capital Expenditure Actual F21	Capital Expenditure Forecast F22	Capital Expenditure Forecast F23	Capital Expenditure Forecast F24	Capital Expenditure Forecast F25	Extension Project, Y=Yes, N=No (11)	Current or Potential Application (12)	Appendix J Reference	Name of Strategy, Plan or Study to which Project is Linked	Appendix K Reference	Program of Projects (Y/N)	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
Generation																														
		Hydroelectric																												
		Growth																												
		Redevelopment / Rehabilitation																												
		Dam Safety																												
1	G000489	Bridge River 2 - Strip and Recoat Penstock 2 Interior	Sustaining	Implementation	F2023	F2021	F2020	35.3	F2023	N/A - In Implementation	35.3	-	-	28.9	0.2	-	4.3	4.7	18.5	0.2	-	N		Page 7	Bridge River Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Page 11 Page 5	N	Committed		
2	G000057	Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)	Sustaining	Implementation	F2023	F2019	F2018	23.5	F2023	N/A - In Implementation	23.5	-	-	29.2	0.0	-	0.7	6.8	12.2	0.1	-	N		Page 15	Cheakamus Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Page 14 Page 5	N	Committed		
3	G000640	Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment	Sustaining	Implementation	F2023	F2021	F2016	43.3	F2023	N/A - In Implementation	43.3	-	17.5	17.5	1.2	-	9.8	17.2	3.0	0.2	-	N		Page 48	Coquitlam-Buntzen System Facility Asset Plan	Page 31	N	Committed		
4	G003129	Revelstoke Replace Downie Slide Instrumentation (Note A)	Sustaining	Implementation	F2022	F2021	F2020	19.6	F2022	N/A - In Implementation	19.6	-	-	15.0	-	-	7.2	6.3	0.2	-	-	N			Revelstoke Facility Asset Plan	Page 39	N	Committed		
5	G000657	Comox - Puntledge Flow Control Improvements (Note A)	Sustaining	Definition	F2025	F2022	F2020			57 - 34		-	-	-	-	-	2.3	2.4	3.2	4.5	13.1	N		Page 17	Puntledge Facility Asset Plan	Page 37	N	For Prioritization	12	
6	G000585	John Hart Dam Seismic Upgrade	Sustaining	Definition	F2030	F2023	F2020			739 - 432		-	-	-	-	-	12.9	9.2	10.9	32.3	91.4	N	Section 44.2	Page 32	Campbell River Systems Engineering Assessment. John Hart Facility Asset Plan	Page 3 Page 22	N	For Prioritization	11	
7	G000668	Ladore Spillway Seismic Upgrade	Sustaining	Definition	F2028	F2024	F2021			269 - 155		-	-	-	-	-	2.4	5.6	3.2	10.0	17.2	N	Section 44.2	Page 44	Campbell River Systems Engineering Assessment. Ladore Facility Asset Plan	Page 3 Page 29	N	For Prioritization	10	
8	G000195	Mica - Intake Gantry Crane Refurbishment	Sustaining	Definition	F2024	F2022	F2020			5 - 4		-	-	-	5.4	0.1	0.3	0.0	0.0	5.0	0.1	N			Mica Facility Asset Plan	Page 33	N	For Prioritization	9	
9	G000525	Strathcona Upgrade Discharge	Sustaining	Definition	F2027	F2024	F2020			337 - 194		-	-	-	-	-	7.1	7.2	6.5	4.4	65.7	N	Section 44.2	Page 78	Campbell River Systems Engineering Assessment. Strathcona Facility Asset Plan	Page 3 Page 47	N	For Prioritization	11	
10	G003555	W.A.C. Bennett Dam Seal Low Level Outlets	Sustaining	Definition	F2026	F2023	F2021			53 - 32		-	-	-	-	-	1.7	0.9	0.9	1.0	10.6	N		Page 89	G.M. Shrum Facility Asset Plan	Page 18	N	For Prioritization	11	
11	G000001	Alouette - Environmental Flow Discharge Upgrade and LLO Sealing	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	0.3	0.6	3.4	N			Alouette Facility Asset Plan	Page 7	N	For Prioritization	10	
12	G000011	Alouette Improve Headworks & Surge Tower Seismic Stability	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	56.7	1.4	2.0	2.4	26.4	20.8	N		Page 1	Alouette Facility Asset Plan	Page 7	N	For Prioritization	11	
13	G000042	Ash River Extend Life of Steel Penstock	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	20.5	0.3	0.5	1.0	3.8	14.8	0.3	N		Page 3	Ash River Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Page 9 Page 5	N	For Prioritization	10	
14	G003467	Bridge River 1 - Improve Slope Drainage	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	(0.4)	0.4	0.5	4.2	9.4	N			Bridge River Facility Asset Plan	Page 11	N	For Prioritization	9.5	
15	G000485	Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	0.2	0.4	0.6	0.5	1.0	N	Section 44.2	Page 7	Bridge River Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Page 11 Page 5	N	For Prioritization	10	
16	G003133	GMS – Install Further Instrumentation for Monitoring Embankment Condition	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	0.4	0.1	0.6	1.1	3.7	N			G.M. Shrum Facility Asset Plan	Page 18	N	For Prioritization	10	
17	G000556	Hugh Keenleyside - Spillway and Low Level Outlets Concrete Upgrade	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	0.1	0.9	0.5	0.4	9.5	N		Page 30	Hugh Keenleyside Facility Asset Plan	Page 20	N	For Prioritization	10.5	
18	G003723	Hugh Keenleyside - Fire Protection System Upgrade	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	8.6	0.2	0.4	0.5	3.1	4.4	N			Hugh Keenleyside Facility Asset Plan	Page 20	N	For Prioritization	9	
19	G000459	La Joie - Dam Improvements	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	5.4	4.1	3.5	N	Section 44.2	Page 40	La Joie Facility Asset Plan Bridge River System Study	Page 27 Page 1	N	For Prioritization	12	
20	G003365	Mica - Discharge Facilities Seismic and Reliability Upgrades	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	0.5	1.6	1.5	2.0	2.2	N	Section 44.2	Page 55	Mica Facility Asset Plan	Page 33	N	For Prioritization	11	
21	G000467	Terzaghi - Spillway Chute Access Improvement	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	0.1	0.4	1.4	6.7	N			Bridge River Facility Asset Plan	Page 11	N	For Prioritization	11	
22	G003653	Various Sites - Reservoir Booms Replacement - F2020	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	9.8	9.9	0.5	0.9	8.6	9.1	0.6	N		Page 83			Y	For Prioritization	9.5	
23	G003554	W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	11.4	11.4	1.0	0.7	5.6	9.0	6.2	N		Page 86	G.M. Shrum Facility Asset Plan	Page 18	N	For Prioritization	11	
24	G004327	Bridge River 1 - Penstock Concrete Foundation Refurbishment	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	21.8	-	-	2.6	18.4	0.8	N		Page 5	Bridge River Facility Asset Plan	Page 11	N	For Prioritization	10	
25	G000052	Cheakamus - Dam Improvements	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	4.7	N	Section 44.2	Page 13	Cheakamus Facility Asset Plan	Page 14	N	For Prioritization	10.5	
26	G000131	G.M. Shrum - Intake Operating Gate and Intake Maintenance Gate Refurbishment	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	0.3	1.0	0.8	N		Page 27	G.M. Shrum Facility Asset Plan	Page 18	N	For Prioritization	9.5	
27	G003336	G.M. Shrum - Intake Operating Gate Hydraulic Upgrade	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	0.1	0.8	1.5	0.5	N		Page 27	G.M. Shrum Facility Asset Plan	Page 18	N	For Prioritization	9.5	
28	G002183	Hugh Keenleyside - Cranes Upgrade	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	0.6	N			Hugh Keenleyside Facility Asset Plan	Page 20	N	For Prioritization	9	
29	G003811	Kootenay Canal - Canal Concrete Liner Joints Upgrade	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	1.0	N		Page 35	Kootenay Canal Facility Asset Plan	Page 25	N	For Prioritization	10	
30	G003234	Lake Buntzen 1 - Penstock Interior Restoration	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	1.7	7.0	N		Page 50	Coquitlam-Buntzen System Facility Asset Plan	Page 31	N	For Prioritization	10	
31	G003131	Mica - Little Chief Inclinometers Installation	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	13.4	-	-	0.5	1.2	11.6	N			Mica Facility Asset Plan	Page 33	N	For Prioritization	9	
32	G004405	Ruskin - Left Abutment Slope Sinkhole Remediation	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	8.0	-	-	-	5.2	2.8	-	-	N					N	For Prioritization	11	
33	G000543	Seton - Canal Flow Control Structure Upgrade	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	1.8	N		Page 71	Seton Facility Asset Plan Bridge River System Study	Page 41 Page 1	N	For Prioritization	10.5	
34	G000295	Sugar Lake - Dam Abutments Upgrade	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	1.8	N			Shuswap Facility Asset Plan	Page 45	N	For Prioritization	10.5	
35	G000470	Terzaghi - Dam Instrumentation Upgrade	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	0.5	N			Bridge River Facility Asset Plan	Page 11	N	For Prioritization	10	
36	G000468	Terzaghi - Low Level Discharge Reliability Improvement	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	1.0	3.9	N		Page 81	Bridge River Facility Asset Plan Bridge River System Study	Page 11 Page 1	N	For Prioritization	10	
37	G004064	Various Sites - Probabilistic Seismic Hazard Model Update	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	0.6	1.2	2.4	N					N	For Prioritization	10	
38	G004172	Various Sites - Spillway Gate Standby Power Improvements	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	10.8	8.7	-	-	1.7	9.1	8.7	N		Page 85			N	For Prioritization	11	
		Sustaining - Other																												
39	G000571	Cheakamus Replace Units 1 and 2 Turbine Inlet Valves	Sustaining	Implementation	F2023	F2015	F2014	10.7	F2020	N/A - In Implementation	12.4	-	6.1	6.0	0.1	-	1.4	1.9	1.8	0.1	-	N			Cheakamus Facility Asset Plan	Page 14	N	Committed		
40	G000127	G.M. Shrum G1 to 10 Control System Upgrade	Sustaining	Implementation	F2023	F2016	F2013	75.0	F2023	N/A - In Implementation	75.0	5.6	-	32.7	0.3	0.5	5.9	10.5	6.2	0.3	0.1	N		Page 20	G.M. Shrum Facility Asset Plan	Page 18	N	Committed		
41	G000114	G.M. Shrum Upgrade HVAC System	Sustaining	Implementation	F2024	F2021	F2016	27.0	F2024	N/A - In Implementation	27.0	-	-	-	19.3	0.8	0.5	1.0	9.3	7.2	0.8	N		Page 22	G.M. Shrum Facility Asset Plan	Page 18	N	Committed		
42	G003035	Hugh Keenleyside Recoat Navlock Gates	Sustaining	Implementation	F2023	F2020	F2019	17.2	F2023	N/A - In Implementation	17.2	-	7.2	6.2	0.0	-	2.2	7.8	2.5	0.0	-	N			Hugh Keenleyside Facility Asset Plan	Page 20	N	Committed		
43	G000747	Hugh Keenleyside Replace Service Water Piping (Note A)	Sustaining	Implementation	F2022	F2019	F2018	11.9	F2021	N/A - In Implementation	10.8	-	-	11.0	-	-	1.1	7.6	0.4	-	-	N			Hugh Keenleyside Facility Asset Plan	Page 20	N	Committed		
44	G000158	Jordan - Upgrade Governor & PRV Controls	Sustaining	Implementation	F2023	F2021	F2019	15.2	F2023	N/A - In Implementation	15.2	-	-	11.9	0.5	-	0.5	5.6	4.0	0.5	-	N			Jordan River Facility Asset Plan	Page 23	N	Committed		
45	G003211	Mica - Reactor 5RX3 Replacement	Sustaining	Implementation	F2024	F2020	F2020	21.4	F2021	N/A - In Implementation	42.8	-	15.9	15.9	5.4	-	16.0	11.7	5.2	1.7	-	N		Page 52	Mica Facility Asset Plan	Page 33	N	Committed		
46	G000172	Mica Modernize Controls	Sustaining	Implementation	F2024	F2019	F2018	47.8	F2024	N/A - In Implementation	56.3	7.0	15.4	15.4	15.4	-	10.7	11.9	8.1	3.4	-	N		Page 57	Mica Facility Asset Plan	Page 33	N	Committed		
47	G003207	Mica Replace Units 1 to 4 Generator Transformers	Sustaining	Implementation	F2023	F2018	F2017	82.1	F2023	N/A - In Implementation	79.8	13.0	30.6	19.5	1.9	-	17.9	17.4	8.8	1.9	-	Y		Page 59	Mica Facility Asset Plan	Page 33	N	Committed		
48	G003456	Mica Upgrade 600V Circuit Breakers (Note A)	Sustaining	Implementation	F2022	F2019	F2016	18.9	F2021	N/A - In Implementation	25.7	-	-	23.7	-	-	6.2	10.9	1.8	-	-	N		Page 63	Mica Facility Asset Plan	Page 33	N	Committed		
49	G000801	Mica Upgrade HVAC System	Sustaining	Implementation	F2023	F2020	F2018	39.9	F2023	N/A - In Implementation	39.9	-	-	29.4	4.9	-	0.9	8.9	18.0	4.9	-	N		Page 65	Mica Facility Asset Plan	Page 33	N	Committed		
50	G000220	Peace Canyon - 600V Circuit Breaker Upgrades	Sustaining	Implementation	F2024	F2020	F2019	9.1	F2023	N/A - In Implementation	9.1	-	-	5.1	3.4	-	0.2	0.4	4.9	2.5	-	N			Peace Canyon Facility Asset Plan	Page 35	N	Committed		
51	G000241	Puntledge Recoat Interior and Exterior of Steel Penstock	Sustaining	Implementation	F2022	F2019	F2017	35.7	F2022	N/A - In Implementation	35.6	-	22.9	11.6	-	-	10.2	12.2	2.6	-	-	N		Page 67	Puntledge Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Page 37 Page 5	N	Committed		
52	G003373	Revelstoke Replace Fire Alarm System (Note A)	Sustaining	Implementation	F2022	F2021	F2019	9.2	F2023	N/A - In Implementation	9.2	-	-	7.1	-	-	0.9	5.6	0.1	-	-	N			Revelstoke Facility Asset Plan	Page 39	N	Committed		
53	G000834	Seven Mile - Replace T1 Transformer (Note A)	Sustaining	Implementation	F2023	F2021	F2020	12.4	F2023	N/A - In Implementation	12.4	-	-	-	10.1	-	0.3	3.2	5.4	0.7	-	N			Seven Mile Facility Asset Plan	Page 43	N	Committed		
54	G000822	Seven Mile Upgrade Powerhouse Crane Controls (Note A)	Sustaining	Implementation	F2022	F2021	F2020	11.9	F2022	N/A - In Implementation	11.9	-	-	9.7	-	-	3.5	5.3	0.5	-	-	N			Seven Mile Facility Asset Plan	Page 43	N	Committed		
55	G003515	Various - Water License Renewal	Sustaining	Implementation	F2023	F2020	F2017	11.3	F2022	N/A - In Implementation	11.3	-	-	8.6	-	-	1.1	1.3	1.2	-	-	N					N	Mandatory		
56	G000342	Wahleach Recoat Penstock (Interior and Exterior)	Sustaining	Implementation	F2024	F2019	F2018	21.8	F2022	N/A - In Implementation	21.8	-	11.3	-	5.9	0.0	4.3	0.1	2.5	3.6	0.0	N			Wahleach Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Page 49 Page 5	N	Committed		
57	G000334	Wahleach Refurbish Generator	Sustaining	Implementation	F2023	F2020	F2018	51.2	F2022	N/A - In Implementation	51.2	-	-	48.5	1.2	-	10.1	7.9	12.9	1.2	-	Y		Page 91	Wahleach Facility Asset Plan	Page 49	N	Committed		
58	G001047	Waneta U3 Life Extension	Sustaining	Implementation	F2023	F2021	Note B	37.5	F2021	N/A - In Implementation	37.5	-	-	30.4	-	-	7.5	21.6	-	-	-	Y		Page 93			N	Committed		
59	G000776	Bridge River 1 Replace Units 1-4 Generators / Governors	Sustaining	Definition	F2031	F2024	F2021			333 - 202 (Note C)		-	-	-	-	-	1.9	4.8	2.5	11.4	19.4	Y	CPCN	Page 9	Bridge River Facility Asset Plan	Page 11	N	For Prioritization	10.5	
60	G003338	Various Sites - Cutler Hammer Exciters Upgrade	Sustaining	Definition	TBD	F2022	F2021			TBD		-	2.6	2.3	2.0	2.0	0.0	2.0	2.0	2.0	2.0	N			Cutler-Hammer Exciter Risk Mitigation Review	Page 16	N	For Prioritization	10	
61	G003584	Whatshan - Governor Replacement	Sustaining	Definition	F2024	F2022	F2021			Note D		-	-	-	5.4	-	0.1	0.6	2.5	2.2	-	N			Whatshan Facility Asset Plan	Page 51	N	For Prioritization	9.5	
62	G000031	Ash River - Upgrade Communication Systems	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	8.7	0.0	0.6	0.9	3.1	4.2	N			Ash River Facility Asset Plan	Page 9	N	For Prioritization	10	
63	G000128	GMS - Unwatering System Refurbishment	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	6.2	0.3	0.6	0.6	1.7	5.0	N		Page 29	G.M. Shrum Facility Asset Plan	Page 18	N	For Prioritization	9	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F21	Capital Addition Forecast F22	Capital Addition Forecast F23	Capital Addition Forecast F24	Capital Addition Forecast F25	Capital Expenditure Actual F21	Capital Expenditure Forecast F22	Capital Expenditure Forecast F23	Capital Expenditure Forecast F24	Capital Expenditure Forecast F25	Extension Project, Y=Yes, N=No (11)	Current or Potential Application (12)	Appendix J Reference	Name of Strategy, Plan or Study to which Project is Linked	Appendix K Reference	Program of Projects (Y/N)	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
64	G003058	Kootenay Canal - U1 - U4 Generators Refurbishment	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	0.4	0.8	3.1	TBD	Potential CPCN or Section 44.2	Page 37	Kootenay Canal Facility Asset Plan	Page 25	N	For Prioritization	10.5	
65	G000952	Kootenay Canal Modernize Controls	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	0.4	0.9	1.4	0.7	7.6	N		Page 38	Kootenay Canal Facility Asset Plan	Page 25	N	For Prioritization	10	
66	G000168	Lake Buntzen 1 - Generator Replacement	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	0.5	1.6	1.1	3.3	3.7	TBD		Page 46	Coquitlam-Buntzen System Facility Asset Plan	Page 31	N	For Prioritization	10	
67	G000519	LDR - Upgrade Communication Systems	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	7.4	-	0.8	1.8	3.5	1.3	N			Ladore Facility Asset Plan	Page 29	N	For Prioritization	10	
68	G000181	Mica - U1 - U4 Circuit Breaker and Iso-phase Bus Replacement	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	15.0	0.1	0.7	4.2	11.5	12.5	Y		Page 54	Mica Facility Asset Plan	Page 33	N	For Prioritization	10	
69	G003835	Peace Canyon - U1 - U4 Exciter Replacement	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	0.4	0.4	0.8	0.6	N			Peace Canyon Facility Asset Plan	Page 35	N	For Prioritization	10	
70	G000252	Revelstoke - U1 - U4 Stator Replacement	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	0.5	1.2	2.9	5.6	TBD	Potential CPCN or Section 44.2	Page 69	Revelstoke Facility Asset Plan	Page 39	N	For Prioritization	10.5	
71	G003026	Seton - Upgrade Unit	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	0.0	2.0	3.6	6.0	60.4	Y	Potential CPCN or Section 44.2	Page 73	Seton Facility Asset Plan	Page 41	N	For Prioritization	10	
72	G003449	Various Facilities Replace Water Level Gauges	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	10.7	0.3	0.3	0.9	4.9	4.6	0.2	N					N	For Prioritization	10	
73	G000035	Ash River - Generator Replacement	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	0.0	0.1	0.4	0.7	0.9	N			Ash River Facility Asset Plan	Page 9	N	For Prioritization	10	
74	G004409	Bridge River 2 - Transformer Replacement	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	7.9	-	-	0.5	6.5	0.8	-	N					N	For Prioritization	12	
75	G003826	G.M. Shrum - Pauwels Transformer Life Extension	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	0.1	0.3	0.8	2.2	N			G.M. Shrum Facility Asset Plan	Page 18	N	For Prioritization	9.5	
76	G003302	G.M. Shrum - Physical Security Upgrade - Phase I	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	0.6	0.7	1.2	N		Page 24	G.M. Shrum Facility Asset Plan	Page 18	N	For Prioritization	9.5	
77	G003837	G.M. Shrum - U5 Generator Refurbishment	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	2.7	TBD		Page 25	G.M. Shrum Facility Asset Plan	Page 18	N	For Prioritization	10.5	
78	G000124	G.M. Shrum - U6 Generator Refurbishment	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	1.1	1.7	TBD		Page 26	G.M. Shrum Facility Asset Plan	Page 18	N	For Prioritization	10.5	
79	G000966	Kootenay Canal - Fire Detection and Alarm System Replacement	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	0.3	0.8	3.5	N			Kootenay Canal Facility Asset Plan	Page 25	N	For Prioritization	9.5	
80	G001898	Ladore - Unit Transformer Upgrade	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	0.6	4.0	N			Ladore Facility Asset Plan	Page 29	N	For Prioritization	10	
81	G002326	La Joie - Governor Pressure Regulating Valve Replacement	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	0.4	1.4	3.5	7.0	N		Page 42	La Joie Facility Asset Plan	Page 27	N	For Prioritization	9.5	
82	G004349	Mica - Crash-rated Gate Replacement	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	0.2	N					N	For Prioritization	9.5	
83	G003980	Mica - Nagle Creek Crossing Infrastructure Refurbishment	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	0.4	N			Mica Facility Asset Plan	Page 33	N	For Prioritization	9	
84	G000183	Mica - U1 - U2 Turbine Overhaul	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	1.2	3.6	TBD	Potential CPCN or Section 44.2	Page 61	Mica Facility Asset Plan	Page 33	N	For Prioritization	10.5	
85	G000231	Peace Canyon - High and Low Pressure Piping Replacement	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	0.3	0.5	0.5	N			Peace Canyon Facility Asset Plan	Page 35	N	For Prioritization	9	
86	G002413	Peace Canyon - Powerhouse, Intake and Tailrace Crane Upgrades	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	0.9	1.1	N			Peace Canyon Facility Asset Plan	Page 35	N	For Prioritization	9	
87	G004197	Revelstoke - Intake and Tailrace Gantry Crane Upgrades	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	1.1	4.7	N			Revelstoke Facility Asset Plan	Page 39	N	For Prioritization	9	
88	G004155	Seven Mile - U1 - U3 Turbine Upgrade	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	1.3	TBD	Potential CPCN or Section 44.2	Page 76	Seven Mile Facility Asset Plan	Page 43	N	For Prioritization	10.5	
89	G000436	Seven Mile - U1 - U4 Controls Upgrade	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	0.3	0.9	2.6	4.3	N		Page 75	Seven Mile Facility Asset Plan	Page 43	N	For Prioritization	9.5	
90	G004410	Various Sites - PCB Lighting Remediation (F2022-F2024)	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	9.4	-	-	2.5	3.4	3.5	-	N					N	For Prioritization	10	
		Add: Programs and Projects Less than $5M												45.4	56.1	58.4			56.7	51.0	44.2									
		TOTAL Hydroelectric												**439.2**	**219.1**	**230.4**			**293.3**	**321.9**	**525.9**									
		Diesel																												
		Add: Programs and Projects Less than $5M												4.5	14.8	9.6			10.2	6.2	6.3									
		TOTAL Diesel												**4.5**	**14.8**	**9.6**			**10.2**	**6.2**	**6.3**									
		Thermal																												
91	G003189	Burrard - Modify for Post Generation Operations	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	4.9	-	0.0	0.6	3.6	0.2	N			Burrard Synchronous Condense Facility Asset Plan	Page 13	N	For Prioritization	9	
92	G003760	Fort Nelson - U2 Steam Turbine Overhaul	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	0.4	N			Fort Nelson Generating Station Facility Asset Plan	Page 17	N	For Prioritization	10	
		Add: Programs and Projects Less than $5M										-	-	0.6	0.6	7.6			0.7	1.0	6.3									
		TOTAL Thermal												**0.6**	**0.6**	**12.5**			**1.3**	**4.6**	**7.0**									
		Generation Total												**444.3**	**234.5**	**252.4**			**304.8**	**332.8**	**539.1**									
		Portfolio Delivery Adjustment												**(1.1)**	**(11.3)**	**(3.1)**			**(3.9)**	**(21.8)**	**(38.7)**									
		Total												**443.2**	**223.2**	**249.3**			**300.9**	**311.0**	**500.4**									

Note A: ISA is in the fiscal year following the ISD because of a 3 month span between project in-service and finalization of the in-service additions by Finance.
Note B: Given the nature of the project, a definition phase was not undertaken.
Note C: $326M to $207M is the latest Pre-Implementation Cost Estimate that is reflected in the project's CPCN Application filed close to the submission date of this RRA.
Note D: Project was accelerated under the Project and Portfolio Management (PPM) scaling guidelines by combining the Feasibility Design Stage and Definition Phase, and as such does not yet have a published cost estimate. Project is considered low risk and low complexity and there is little to no Feasibility Design work required.

Notes:
(1) All information provided is current as of January 1, 2021.
(2) Some projects that are in-service or forecast to be in-service at the end of fiscal 2022 may have trailing expenditures that result in capital additions in the Test Period. These expenditures and associated capital additions have been aggregated and included in the line item "Programs and Projects Less than $5M".
(3) Project / Program dollars are generally capitalized starting either in the feasibility stage of Identification phase or in the Definition phase.
(4) Forecast ISD is the expected in-service date for the project.
(5) Start Date of Construction is the Implementation Approval Date. For projects in Definition, the Start Date of Construction is the forecast Implementation Approval Date.
(6) Definition Approval Date is the fiscal year that the project received Definition phase approval.
(7) Implementation Approval $ is the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation.
(8) Pre-Implementation phases are: Initiation, Identification and Definition. Refer to Appendix N, Section 2.7 for further discussion on pre-Implementation phases. Pre-Implementation cost estimates are provided where an engineering estimate is available. N/A indicates that an engineering estimate is not yet available, or that the project is in Implementation phase.
(9) Authorized Amount is the 'Authorized' total capital cost of the project.
(10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation.
(11) An extension is a project that expands the service area or capacity of a utility plant or system, in accordance with paragraph 13 of BC Hydro's 2018 Capital Filing Guidelines filed with the BCUC on January 17, 2020.
(12) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate, or in accordance with BCUC Decision and Order G-47-18 and directive 29 of BCUC Decision and Order G-246-20.

Use of To Be Determined (TBD):
For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD), Start Date of Construction and Extension Project, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very
different project scope, schedule and cost. As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start of Construction Date are generally only provided for projects in the Definition phase and later phases. For Extension Projects, TBD has been provided where both extension and non-extension alternatives are being investigated.

Appendix I - F2023-F2025 RRA - Transmission
Projects greater than $5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F23-F25) as at January 1, 2021 (1), (2)
$ Million

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F21	Capital Addition Forecast F22	Capital Addition Forecast F23	Capital Addition Forecast F24	Capital Addition Forecast F25	Capital Expenditure Actual F21	Capital Expenditure Forecast F22	Capital Expenditure Forecast F23	Capital Expenditure Forecast F24	Capital Expenditure Forecast F25	Extension Project, Y=Yes, N=No (11)	Current or Potential Application (12)	Appendix J Reference	Name of Strategy, Plan or Study to which Project is Linked	Appendix K Reference	Program of Projects (Y/N)	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
Transmission																														
		Growth Capital Expenditures																												
		Regional System Reinforcement																												
1	92423	Bridge River Transmission Project	Growth	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	(1.0)	2.3	2.5	13.8	29.5	Y	CPCN	Page 104	Bridge River Transmission System Upgrade - NITS Study	Page 75	N	For Prioritization	10.0	
2	901572	North Montney Region - Electrification	Growth	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	0.0	-	5.8	2.5	-	Y	CPCN	Page 136	Transmission System Study for North Montney Region Electrification	Page 95	N	For Prioritization	10.5	
3	94034	West Kelowna Transmission and Westbank Upgrade Projects	Growth	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	0.5	1.0	6.9	9.7	10.4	Y	CPCN	Page 162	West Kelowna Area Study	Page 96	N	For Prioritization	9.5	
4	900598	West End - Substation Construction and System Reinforcement	Growth	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	1.3	6.1	4.8	5.1	14.9	Y	CPCN	Page 160	Downtown Vancouver Electric Supply Plan	Page 77	N	For Prioritization	10.5	
5	901858	Peace to Kelly Lake - Remedial Action Scheme Upgrade	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	8.1	0.0	-	0.3	4.4	3.4	0.0	N					N	For Prioritization	11.0	
6	900266	East Vancouver - Substation Construction	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	0.1	Y	CPCN	Page 110	Downtown Vancouver Electric Supply Plan	Page 77	N	For Prioritization	10.5	
7	902126	Sunshine Coast - Transmission Reinforcement	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	0.5	2.6	6.4	Y		Page 151			N	Mandatory		
		Bulk System Reinforcements																												
8	901562	Cranbrook 5L94 - Line Reactor Replacement	Growth	Definition	F2025	F2022	F2020			13 - 10		-	-	-	-	9.5	0.0	0.1	0.2	5.7	3.1	N					N	Mandatory		
9	900992	Lower Mainland - Capacitive and Reactive Power Reinforcement	Growth	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	0.2	2.4	2.5	1.5	32.3	Y	Potential CPCN	Page 123	Burrard Synchronous Condensers Replacement Study	Page 76	N	For Prioritization	12.0	
10	901574	Prince George to Terrace Capacitors Project	Growth	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	2.1	2.8	-	-	-	Y	Exempt - Transmission Exemption Regulation	Page 146			N	For Prioritization	11.0	
		Station Expansion & Modification																												
11	93788	Capilano Substation Upgrade	Growth	Implementation	F2025	F2020	F2018	87.4	F2025	N/A - In Implementation	87.4	-	-	-	-	64.4	6.3	5.9	19.6	18.2	6.9	Y		Page 106	Integrated Planning Report for Capilano and Lynn Valley Substations and Distribution Area	Page 80	N	Committed		
12	92910	Clayburn Substation Upgrade	Growth	Implementation	F2024	F2021	F2020	35.7	F2024	N/A - In Implementation	35.7	-	-	-	30.0	0.4	1.9	14.4	9.8	2.8	0.4	Y		Page 108	Abbotsford Area Study	Page 53	N	Committed		
13	92907	Mount Lehman Substation Upgrade (Note A)	Growth	Implementation	F2023	F2020	F2019	59.1	F2023	N/A - In Implementation	59.1	-	-	-	58.8	-	21.7	15.9	13.3	1.9	-	Y		Page 128	Abbotsford Area Study	Page 53	N	Committed		
14	900268	Horne Payne - Feeder Section Addition	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	0.1	Y		Page 114	North Burnaby Area Study	Page 87	N	For Prioritization	7.5	
		Generator Interconnections																												
		Transmission Load Interconnections																												
15	901580	Customer IPID - 901580:[redacted]	Growth	Definition	F2026	F2024	F2020			18 - 10		-	-	-	-	-	-	0.7	0.6	6.2	4.3	Y					N	Mandatory		
16	901573	Customer IPID - 901573:[redacted]	Growth	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	0.1	2.1	7.2	13.4	Y					N	Mandatory		
17	901851	Customer IPID - 901851:[redacted]	Growth	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	9.7	0.0	2.6	3.3	2.2	1.6	Y					N	Mandatory		
18	901581	Customer IPID - 901581:[redacted]	Growth	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	0.3	4.2	7.8	6.2	7.0	Y					N	Mandatory		
19	901940	Customer IPID - 901940:[redacted]	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	10.2	0.0	0.6	3.0	6.6	-	Y					N	Mandatory		
20	902121	Customer IPID - 902121:[redacted]	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	7.0	-	0.5	3.0	3.5	-	Y					N	Mandatory		
21	901943	Customer IPID - 901943:[redacted]	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	77.9	9.3	0.0	2.2	26.6	49.1	9.3	Y	CPCN				N	Mandatory		
22	901938	Customer IPID - 901938:[redacted]	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	11.0	-	-	6.0	5.0	-	-	Y					N	Mandatory		
		Add: Programs and Projects Less than $5M												9.6	10.7	17.2			11.0	7.2	9.3									
		TOTAL Growth Capital Additions												**9.6**	**196.5**	**127.5**			**132.9**	**155.5**	**148.9**									
		Sustaining Capital Expenditures																												
		Circuit Breakers																												
23	900243	SPG Metalclad Switchgear Replacement	Sustaining	Implementation	F2025	F2020	F2019	53.6	F2025	N/A - In Implementation	53.6	-	-	-	25.4	16.9	3.3	8.2	17.6	6.6	4.3	Y		Page 149	Sperling Asset Plan	Page 92	N	Committed		
24	901248	Kimberley to Marysville - Substation Relocation	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	0.9	0.8	1.5	4.0	N		Page 119	Asset Management Strategy - Section 2.2.2: Circuit Breakers	Page 60	N	For Prioritization	10.0	
25	901612	Pemberton - Substation Rebuild	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	9.8	-	0.4	3.1	5.1	1.2	Y			Asset Management Strategy - Section 2.2.2: Circuit Breakers	Page 60	N	For Prioritization	10.0	
26	901613	Maple Ridge - Feeder Section 60 Series Refurbishment	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	0.5	1.1	6.4	Y		Page 127	Asset Management Strategy - Section 2.2.2: Circuit Breakers	Page 60	N	For Prioritization	10.0	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F21	Capital Addition Forecast F22	Capital Addition Forecast F23	Capital Addition Forecast F24	Capital Addition Forecast F25	Capital Expenditure Actual F21	Capital Expenditure Forecast F22	Capital Expenditure Forecast F23	Capital Expenditure Forecast F24	Capital Expenditure Forecast F25	Extension Project, Y=Yes, N=No (11)	Current or Potential Application (12)	Appendix J Reference	Name of Strategy, Plan or Study to which Project is Linked	Appendix K Reference	Program of Projects (Y/N)	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
		Other Power Equipment																												
27	92073	American Creek - Capacitor Protection Control Upgrade	Sustaining	Implementation	F2023	F2021	F2018	21.3	F2024	N/A - In Implementation	21.3	-	-	16.1	0.3	-	3.6	5.6	5.3	0.3	-	N			Asset Management Strategy - Protection and Control (P&C)	Page 56	N	Committed		
28	900575	Barnard 50/60 Feeder Section Replacement	Sustaining	Implementation	F2023	F2019	F2018	47.9	F2022	N/A - In Implementation	47.9	-	39.0	5.2	-	-	17.9	8.6	0.8	-	-	N		Page 100	Barnard Asset Plan	Page 73	N	Committed		
29	900564	Hundred Mile House T1/T2 EOL Replacement	Sustaining	Implementation	F2023	F2020	F2019	20.5	F2023	N/A - In Implementation	20.5	-	-	15.5	0.0	-	4.4	7.8	2.1	0.0	-	Y			Asset Management Strategy - Section 2.2.16: Power Transformers	Page 69	N	Committed		
30	93731	Jordan River - Switchyard Upgrade	Sustaining	Implementation	F2023	F2020	F2019	43.6	F2023	N/A - In Implementation	43.6	-	-	30.4	0.6	-	3.6	15.3	8.2	0.6	-	N		Page 115	Asset Management Strategy - Section 2.2.16: Power Transformers	Page 69	N	Committed		
31	92166	SC Excitation Systems Upgrade - VIT/KLY	Sustaining	Implementation	F2024	F2020	F2014	14.7	F2024	N/A - In Implementation	14.7	-	-	-	12.5	0.1	3.0	4.0	3.1	1.2	0.1	N			Asset Management Strategy - Section 2.2.15: Synchronous Condensers	Page 68	N	Committed		
32	900152	Natal Sub - NTL 60-138 kV Rebuild	Sustaining	Definition	F2025	F2022	F2021			139 - 47		-	-	-	-	42.4	1.1	3.1	8.6	10.8	17.7	Y		Page 130	Natal Asset Plan	Page 85	N	For Prioritization	10.5	
33	94079	Sandspit Substation Replacement	Sustaining	Definition	F2023	F2021	F2020			15 - 12		-	-	12.7	0.4	-	1.3	6.1	5.1	0.4	-	Y			Wood Pole Substation Strategy	Page 97	N	For Prioritization	9.0	
34	94081	Ah-sin-heek - Substation Replacement	Sustaining	Definition	F2023	F2022	F2021			Note B		-	-	9.9	0.0	-	0.3	3.1	6.5	0.0	-	Y			Wood Pole Substation Strategy	Page 97	N	For Prioritization	8.5	
35	900247	Bridge River - T4 Transformer Replacement	Sustaining	Definition	F2023	F2022	F2016			48 - 28		-	-	26.6	0.4	-	1.1	7.2	17.6	0.4	-	N		Page 102	Asset Management Strategy - Section 2.2.16: Power Transformers	Page 69	N	For Prioritization	10.5	
36	901831	Kennedy - 5CX1 Controls Replacement (Emergency)	Sustaining	Definition	F2023	F2022	F2020			14 - 11		-	-	9.6	0.0	-	2.0	5.8	1.8	0.0	-	N					N	For Prioritization	10.5	
37	901224	Oldfield - Substation Feeder Section Upgrade (Note A)	Sustaining	Definition	F2024	F2023	F2021			14 - 4		-	-	-	-	5.2	0.0	0.2	1.8	2.9	0.3	N			Oldfield Substation Asset Plan	Page 89	N	For Prioritization	10.0	
38	901821	Peace to Kelly Lake - Stations Sustainment	Sustaining	Definition	F2027	F2023	F2021			299 - 172		-	-	-	19.1	-	5.6	4.7	15.0	39.4	37.5	N	Section 44.2	Page 140	Asset Management Strategy - Stations - Section 2.2.1 - Buildings Asset Management Strategy - Section 2.2.9 - Series Capacitors Asset Management Strategy - Stations - Section 2.2.10 - Shunt Reactors	Page 59 Page 66 Page 67	N	For Prioritization	11.0	
39	92618	VIT & KLY Hydrogen Gas Sys - Safety Upgrade	Sustaining	Definition	F2025	F2022	F2017			8 - 6		-	-	-	5.0	2.1	0.3	1.2	1.8	1.6	1.2	N			Asset Management Strategy - Section 2.2.15: Synchronous Condensers	Page 68	N	Committed		
40	93705	KI1 60Kv Renovation, 4Kv Decommission & Control Room	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	2.0	2.5	11.8	10.3	N		Page 117	Kidd 1 Asset Plan	Page 82	N	For Prioritization	9.5	
41	92478	Mainwaring Station Upgrade	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	25.1	1.5	3.0	6.8	9.3	17.6	Y	CPCN	Page 125	Mainwaring Asset Plan	Page 84	N	For Prioritization	10.5	
42	92479	Newell Substation Upgrade	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	1.0	2.6	3.3	6.6	Y		Page 134	Newell Asset Plan	Page 86	N	For Prioritization	10.5	
43	92759	Patricia - Substation Upgrade	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	0.7	1.6	3.9	3.1	5.1	N		Page 138	Patricia Asset Plan	Page 91	N	For Prioritization	9.5	
44	900185	Peace Region to Kelly Lake - Reactor Replacement (Phase 2)	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	18.1	0.2	-	0.3	1.0	16.9	0.2	N		Page 142	Asset Management Strategy - Section 2.2.10: Shunt Reactors	Page 67	Y	For Prioritization	10.0	
45	901618	Kelly Lake - Reactor Installation	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	0.4	1.8	3.8	1.5	N			Asset Management Strategy - Section 2.2.15: Synchronous Condensers	Page 68	N	For Prioritization	9.0	
46	901823	Norgate - Substation Bypass	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	0.5	1.1	2.2	1.7	N			Integrated Planning Report for Capilano and Lynn Valley Substations and Distribution Area	Page 80	N	For Prioritization	9.5	
47	900186	Peace Region to Kelly Lake - Reactor Replacement (Phase 3)	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	0.6	5.5	9.2	N		Page 142	Asset Management Strategy - Section 2.2.10: Shunt Reactors	Page 67	Y	For Prioritization	10.0	
48	900187	Peace Region to Kelly Lake - Reactor Replacement (Phase 4)	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	0.8	N		Page 142	Asset Management Strategy - Section 2.2.10: Shunt Reactors	Page 67	Y	For Prioritization	10.0	
49	94080	Telegraph Creek - Substation Replacement	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	0.1	N			Wood Pole Substation Strategy	Page 97	N	For Prioritization	9.0	
		Protection and Control																												
50	93687	GMS Substation - Control Systems Upgrade	Sustaining	Implementation	F2024	F2021	F2020	15.7	F2024	N/A - In Implementation	15.7	-	-	-	13.0	0.1	1.7	2.9	5.3	2.6	0.1	N			Asset Management Strategy - Protection and Control (P&C)	Page 56	N	Committed		
51	900625	NERC CIP V5 Compliance at Medium Impact T&D Stations	Sustaining	Implementation	F2027	F2017	F2018	35.5	F2023	N/A - In Implementation	35.5	-	-	-	-	-	2.4	2.9	4.7	5.0	4.1	N		Page 132	Asset Management Strategy - Protection and Control (P&C)	Page 56	N	Mandatory		
52	900250	Control PLC984 and RTU Replacement (WSN) (Note A)	Sustaining	Definition	F2025	F2023	F2017			10 - 6		-	-	-	-	-	0.3	0.5	1.7	2.0	4.0	N			Asset Management Strategy - Protection and Control (P&C)	Page 56	N	For Prioritization	10.0	
53	901592	Various Sites - NERC CIP-003v7 Implementation	Sustaining	Definition	F2024	F2022	F2021			Note C		-	-	-	36.8	1.5	3.1	6.9	14.9	11.9	1.5	N		Page 156	Asset Management Strategy - Protection and Control (P&C)	Page 56	N	Mandatory		
		Stations Auxiliary Equipment																												
54	900726	Joseph Creek (JOE) Substation Upgrade	Sustaining	Definition	F2024	F2022	F2021			32 - 10		-	-	-	14.3	0.2	0.4	1.0	5.7	7.0	0.2	N			Wood Pole Substation Strategy	Page 97	N	For Prioritization	9.0	
55	901045	Canal Flats - Substation Wood Pole Replacement	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	5.9	-	0.3	0.8	4.8	0.1	Y			Wood Pole Substation Strategy	Page 97	N	For Prioritization	9.0	
56	901049	Skookumchuck - Substation Wood Pole Replacement	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	6.0	-	0.3	0.8	4.9	0.1	Y			Wood Pole Substation Strategy	Page 97	N	For Prioritization	9.0	
57	901244	Cathedral Square - Substation HVAC Upgrade	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	16.0	-	0.9	3.0	6.1	6.1	N			Asset Management Strategy - Section 2.2.1 - Buildings	Page 59	N	For Prioritization	10.0	
58	901048	Lumby #2 - Substation Wood Pole Replacement	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	8.7	-	-	3.5	3.5	1.7	N			Wood Pole Substation Strategy	Page 97	N	For Prioritization	9.0	
59	901040	Port Alberni - Substation Refurbishment	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	0.8	6.9	11.8	N		Page 144	Asset Management Strategy - Section 2.2.1 - Buildings	Page 59	N	For Prioritization	9.5	
60	901090	Prevost - Substation Control Building Upgrade	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	0.0	N			Asset Management Strategy - Section 2.2.1 - Buildings	Page 59	N	For Prioritization	7.5	
61	900724	Woss - Substation Wood Pole Replacement	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	5.6	-	0.3	1.7	3.3	0.3	N			Wood Pole Substation Strategy	Page 97	N	For Prioritization	8.5	
		Stations Risk Mitigation																												
62	92158	Oil Spill Containment - F17/F18 (ALZ / MDN)	Sustaining	Implementation	F2023	F2020	F2017	9.2	F2022	N/A - In Implementation	9.2	-	-	7.9	-	-	2.5	3.1	0.5	-	-	N			Asset Management Strategy - Section 2.2.8: Oil Spill Containment	Page 64	N	Committed		
63	94052	Stations Seismic Upgrade -F16/17 (9 Stations)	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	0.0	0.4	1.6	2.0	1.7	N					N	For Prioritization	9.0	
64	900766	Project IPID - 900766:[redacted]	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	3.1	1.1	2.7	Y					N	For Prioritization	9.0	
		Telecommunications																												
65	92183	Vancouver Island Radio System (Note A)	Sustaining	Implementation	F2024	F2018	F2014	32.5	F2021	N/A - In Implementation	32.5	-	-	-	-	49.7	6.5	9.8	9.6	6.1	0.6	N		Page 154	Asset Management Strategy - Telecom Transport	Page 71	N	Committed		
66	900149	Various Sites - Mountain Top 1603 Replacement	Sustaining	Definition	F2023	F2022	F2020			8 - 5		-	-	5.1	0.2	-	0.8	3.3	0.5	0.2	-	N			Asset Management Strategy - Telecom Transport	Page 71	N	For Prioritization	10.5	
67	900019	System Wide – Bulk Electric System Telecom Equipment Replacement	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	1.2	2.4	3.4	17.0	N	Potential Section 44.2	Page 152	Asset Management Strategy - Telecom Transport	Page 71	N	For Prioritization	11.0	
68	900709	Various Sites - Telecom Analog Private Line Replacement	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	0.4	0.9	0.5	1.0	3.8	N			Analogue 4W Inventory Study	Page 55	N	For Prioritization	9.5	
69	93739	Fraser Valley - Telecom System Reliability Upgrade	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	0.5	2.1	3.8	N			Fraser Valley Reinforcement AIM Study	Page 79	N	For Prioritization	10.0	
70	900033	Various Sites - MPLS Core Router Upgrade	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	2.3	N			Asset Management Strategy - Telecom Transport	Page 71	N	For Prioritization	9.0	
71	902241	Various Sites – Telecom Transport Network Resiliency Enhancement	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	0.4	7.0	6.2	N		Page 158	Telecom Resiliency Strategy	Page 93	N	For Prioritization	10.5	
		Cable Sustainment																												
72	901002	2L146 - Cable Replacement	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	0.0	1.0	2.1	2.0	7.4	Y		Page 96	Asset Management Strategy - Lines - Section 2.1.5 - Underground and Submarine Cables	Page 63	N	For Prioritization	10.0	
73	901623	Coquitlam - 2L51 Partial Replacement	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	9.7	0.3	0.7	2.0	5.2	1.4	N			Asset Management Strategy - Lines - Section 2.1.5 - Underground and Submarine Cables	Page 63	N	For Prioritization	10.0	
74	94057	Gulf Islands - Transmission Reinforcement	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	-	0.2	Y		Page 112	Asset Management Strategy - Lines - Section 2.1.5 - Underground and Submarine Cables	Page 63	N	For Prioritization	10.0	
75	93958	South Fraser Transmission Relocation Project	Sustaining	Deferred	TBD	TBD	TBD			TBD	TBD	-	-	-	-	12.4	(0.1)	-	0.3	9.3	14.2	N		Page 148			N	Mandatory		
		O/H Lines Life Extension																												
76	94035	5L063 Telkwa Relocation	Sustaining	Implementation	F2024	F2021	F2020	66.4	F2024	N/A - In Implementation	66.4	-	7.2	-	40.7	2.7	9.1	10.7	17.8	3.5	2.7	N		Page 98			N	Committed		
77	93729	Long Span Crossing Refurbishment - F17/F18 (1L37)	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	0.3	1.2	1.7	7.1	N		Page 121	Asset Management Strategy - Lines - Section 2.1.4 - Conductors	Page 58	N	For Prioritization	10.0	
		O/H Lines Risk Mitigation																												
78	901645	1X387AMX – Kitsault Transmission Line Hazard Mitigation	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	0.2	1.1	1.6	2.5	N					N	For Prioritization	10.5	
79	901474	2L003 and 2L049 – Transmission Line Crossing Seismic Upgrade (Second Narrows)	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	-	0.1	1.1	N		Page 95	BC Hydro Transmission System Seismic Vulnerability Analysis	Page 74	N	For Prioritization	8.5	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F21	Capital Addition Forecast F22	Capital Addition Forecast F23	Capital Addition Forecast F24	Capital Addition Forecast F25	Capital Expenditure Actual F21	Capital Expenditure Forecast F22	Capital Expenditure Forecast F23	Capital Expenditure Forecast F24	Capital Expenditure Forecast F25	Extension Project, Y=Yes, N=No (11)	Current or Potential Application (12)	Appendix J Reference	Name of Strategy, Plan or Study to which Project is Linked	Appendix K Reference	Program of Projects (Y/N)	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
		ROW Sustainment																												
		Third Party Requested Transmission Line Relocations																												
80	901563	Customer IPID - 901563: [redacted]	Sustaining	Definition	F2024	F2024	F2020			12 - 4		-	-	-	5.7	-	0.0	0.7	2.0	2.9	-	N					N	Mandatory		
81	901807	Customer IPID - 901807: (Note A) [redacted]	Sustaining	Definition	F2023	F2022	F2020			15 - 12		-	-	-	7.9	-	1.0	3.7	2.6	0.5	-	N					N	Mandatory		
		Add: Programs and Projects Less than $5M												190.8	168.6	158.6			170.5	156.5	157.9									
		TOTAL Sustaining Capital Additions												**329.7**	**369.1**	**378.9**			**381.9**	**392.1**	**388.4**									
		Transmission Total																												
		TOTAL Growth Capital Additions												**9.6**	**196.5**	**127.5**			**132.9**	**155.5**	**148.9**									
		TOTAL Sustaining Capital Additions												**329.7**	**369.1**	**378.9**			**381.9**	**392.1**	**388.4**									
		Portfolio Delivery Adjustment												**(81.6)**	**(129.6)**	**36.0**			**(39.8)**	**(18.2)**	**(26.7)**									
		Less: Contributions in Aid of Construction												(12.9)	(17.3)	(51.9)			(29.7)	(26.6)	(16.2)									
		Total												**244.8**	**418.6**	**490.5**			**445.4**	**502.7**	**494.4**									

Note A: ISA is in the fiscal year following the ISD because of a 3 month span between project in-service and finalization of the in-service additions by Finance.
Note B: Project was accelerated under the Project and Portfolio Management (PPM) scaling guidelines by combining the Feasibility Design Stage and Definition Phase, and as such does not yet have a published cost estimate. Project is considered low risk and low complexity and there is little to no Feasibility Design work required.
Note C: Project was accelerated under the Project and Portfolio Management (PPM) scaling guidelines by combining the Feasibility Design Stage and Definition Phase, and as such does not yet have a published cost estimate.

Notes:
(1) All information provided is current as of January 1, 2021.
(2) Some projects that are in-service or forecast to be in-service at the end of fiscal 2022 may have trailing expenditures that result in capital additions in the Test Period. These expenditures and associated capital additions have been aggregated and included in the line item "Programs and Projects Less than $5M".
(3) Project / Program dollars are generally capitalized starting either in the feasibility stage of Identification phase or in the Definition phase.
(4) Forecast ISD is the expected in-service date for the project.
(5) Start Date of Construction is the Implementation Approval Date. For projects in Definition, the Start Date of Construction is the forecast Implementation Approval Date.
(6) Definition Approval Date is the fiscal year that the project received Definition phase approval.
(7) Implementation Approval $ is the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation.
(8) Pre-Implementation phases are: Future, Identification and Definition. Refer to Appendix N, Section 2.7 for further discussion on pre-Implementation phases. Pre-Implementation cost estimates are provided where an engineering estimate is available. N/A indicates that an engineering estimate is not yet available, or that the project is in Implementation phase.
(9) Authorized Amount is the 'Authorized' total capital cost of the project.
(10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation.
(11) An extension is a project that expands the service area or capacity of a utility plant or system, in accordance with paragraph 13 of BC Hydro's 2018 Capital Filing Guidelines filed with the BCUC on January 17, 2020.
(12) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate, or in accordance with BCUC Decision and Order G-47-18 and directive 29 of BCUC Decision and Order G-246-20.

Use of To Be Determined (TBD):
For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD), Start Date of Construction and Extension Project, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule and cost. As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start of Construction Date are generally only provided for projects in the Definition phase and later phases. For Extension Projects, TBD has been provided where both extension and non-extension alternatives are being investigated.

Appendix I - F2023-F2025 RRA - Distribution
Projects greater than $5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F23-F25) as at January 1, 2021 (1), (2)
$ Million

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F21	Capital Addition Forecast F22	Capital Addition Forecast F23	Capital Addition Forecast F24	Capital Addition Forecast F25	Capital Expenditure Actual F21	Capital Expenditure Forecast F22	Capital Expenditure Forecast F23	Capital Expenditure Forecast F24	Capital Expenditure Forecast F25	Extension Project, Y=Yes, N=No (11)	Current or Potential Application (12)	Appendix J Reference	Name of Strategy, Plan or Study to which Project is Linked	Appendix K Reference	Program of Projects (Y/N)	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
Distribution																														
		Growth Capital Expenditures																												
		Customer Driven																												
1	DY-1545	Customer IPID DY-1545 (Note A): [redacted]	Growth	Implementation	F2024	F2020	F2019	3.5	F2025	N/A - In Implementation	10.4	5.8	-	-	-	20.4	10.5	13.8	1.5	0.4	0.1	Y					N	Mandatory		
2	DY-0347	Customer IPID DY-0347: [redacted]	Growth	Definition	F2025	F2022	F2019			30 - 11		-	-	-	-	16.3	0.4	8.7	2.3	4.7	0.1	N					N	Mandatory		
3	901955	Customer IPID 901955: [redacted]	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	0.4	0.8	1.5	4.9	Y					N	Mandatory		
4	902127	Customer IPID 902127: [redacted]	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	0.6	1.1	2.2	Y					N	Mandatory		
5	902128	Customer IPID 902128: [redacted]	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	0.4	0.8	1.5	4.9	Y					N	Mandatory		
		Add: Programs and Projects Less than $5M												253.2	254.0	234.0			249.6	243.7	250.4									
		Total Customer Driven												**253.2**	**254.0**	**270.6**			**255.4**	**252.8**	**262.5**									
		System Expansion and Improvement																												
6	900316	LOH 12F56, 12F62 Voltage Conversion Preparation (LM-BBY-082)	Growth	Implementation	F2023	F2020	F2019	2.8	F2022	N/A - In Implementation	2.8	0.3	-	4.9	-	-	0.3	1.3	3.5	-	-	Y					N	Committed		
7	901518	Mount Lehman New Feeder to Offload Balfour, Mount Lehman and Gloucester Feeders (FV-ABT-042) (Note A)	Growth	Implementation	F2022	F2020	F2019	1.5	F2022	N/A - In Implementation	4.2	0.3	-	5.0	-	-	0.3	4.3	0.6	-	-	Y					N	Committed		
8	93650	Two new CBN Feeders to Offload SMW (LM-FVE-606)	Growth	Definition	F2024	F2022	F2015			7 - 3		0.4	-	-	5.5	-	0.4	4.1	1.4	-	-	Y					N	For Prioritization	9.5	
9	92802	Glenmore Voltage Conversion (LM-NSC-088) (Note A)	Growth	Definition	F2023	F2022	F2013			5 - 3		0.1	-	-	5.1	-	0.1	0.3	4.8	0.0	-	Y					N	For Prioritization	9.5	
10	901355	Norgate - Offload NOR loads to NVR feeders (LM-NSH-074) (Note A)	Growth	Definition	F2023	F2022	F2021			22 - 12		0.2	-	-	12.3	-	0.2	0.6	11.3	0.3	-	Y					N	For Prioritization	9.5	
11	901356	North Vancouver - Offload NVR loads to LYN new feeders (LM-NSH-075) (Note A)	Growth	Definition	F2023	F2022	F2021			14 - 4		0.1	-	-	6.3	-	0.1	0.4	5.8	0.2	-	Y					N	For Prioritization	9.5	
12	900431	Oldfield (OFD) Voltage Conversion 12 to 25kV (NI-NEW-273)	Growth	Definition	F2025	F2023	F2021			13 - 4		0.1	-	-	-	5.6	0.1	1.1	2.3	2.2	0.1	Y					N	For Prioritization	9.5	
13	901132	Three Fleetwood feeders to offload McLellan (FV-FVW-723) (Note A)	Growth	Definition	F2023	F2022	F2020			21 - 12		0.1	-	-	11.9	-	0.1	3.8	7.9	0.1	-	Y					N	For Prioritization	10.0	
14	93669	Three new MLE Feeders to offload CBN (LM-FVE-607)	Growth	Definition	F2024	F2022	F2015			13 - 8		0.2	-	-	9.1	-	0.2	8.0	1.0	-	-	Y					N	For Prioritization	10.0	
15	901891	Downtown Vancouver - Voltage Conversion Preparation for Customer Vaults (LM-VAN-210)	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	0.6	1.7	1.7	1.7	N					N	For Prioritization	8.0	
16	901890	Fleetwood - Distribution Feeder Ductbank and Feeder Installation (FV-FVW-023)	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	16.4	-	0.6	2.8	10.5	2.5	Y					N	For Prioritization	9.5	
17	901949	Fleetwood - Distribution Feeder Ductbank and Feeder Installation (FV-FVW-805)	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	9.4	-	-	2.3	7.1	-	Y					N	For Prioritization	9.5	
18	901950	Langley - MLN 25F32 and MLN 25F33 Offload (FV-FVW-741)	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	5.8	-	-	1.7	4.1	-	Y					N	For Prioritization	8.5	
19	901820	Tofino - New LBH 25F54 Feeder Installation To Offload LBH 25F52 (VI-PAL-010)	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	7.5	-	0.0	5.2	2.4	-	-	Y					N	For Prioritization	8.0	
20	900541	Vancouver Island - Saltspring 25F61 Cable Extension to North Pender Island (VI-GUL-005)	Growth	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	-	-	-	1.5	5.4	14.7	Y		Page 170			N	For Prioritization	8.5	
		Add: Programs and Projects Less than $5M												43.8	50.6	25.5			19.7	46.7	51.9									
		Total System Expansion and Improvement												**53.7**	**108.3**	**62.8**			**70.8**	**78.4**	**70.8**									
		Uneconomic Extension Assistance												**0.4**	**0.4**	**0.4**			**0.4**	**0.4**	**0.4**									
		Total Gross Growth Capital												**307.3**	**362.6**	**333.7**			**326.6**	**331.5**	**333.7**									
		Sustaining Capital Expenditures																												
		System Expansion and Improvement																												
21	900391	Downtown Vancouver - Underground Murrin Feeders to Eliminate H-Frames in Gastown (Note A)	Sustaining	Implementation	F2022	F2019	Note B	26.6	F2021	N/A - In Implementation	26.6	1.7	-	18.1	-	-	2.6	15.5	1.7	-	-	N		Page 165			Y	Committed		
22	900557	H-Frame Elimination - Chinatown (Note A)	Sustaining	Implementation	F2022	F2016	Note B	48.4	F2019	N/A - In Implementation	48.4	12.1	4.1	20.4	-	-	6.6	4.4	-	-	-	N		Page 167			Y	Committed		
23	901822	Mission - Feeder 25F51 Tie (FV-ABT-039)	Sustaining	Identification	TBD	TBD	TBD			TBD	TBD	-	-	-	-	12.1	-	0.3	1.5	8.3	2.0	Y					N	For Prioritization	10.0	
24	901892	100 Mile House - Relocate Sections of Transmission along Hendrix Road (SI-HMH-002)	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	-	5.4	-	0.8	2.3	2.3	-	N					N	For Prioritization	9.5	
25	901081	Gwillim Microwave - Power Supply Upgrade	Sustaining	Future	TBD	TBD	TBD			TBD	TBD	-	-	-	7.4	-	-	2.1	3.2	2.2	-	N					N	For Prioritization	9.0	
		Add: Programs and Projects Less than $5M												38.4	42.0	39.2			29.2	40.5	45.0									
		Total System Expansion and Improvement												**76.9**	**49.4**	**56.6**			**37.8**	**53.2**	**47.0**									
		Asset Replacement																												
26	900556	Various Sites - LED Street Light Conversion	Sustaining	Implementation	F2024	F2018	F2020	74.9	F2024	N/A - In Implementation	74.9	2.1	23.0	21.7	7.4	5.8	6.2	27.4	20.3	4.2	-	N		Page 172	Asset Management Strategy – Section 3.1.8: Street Lighting	Page 99	N	Committed		
		Add: Programs and Projects Less than $5M												128.6	125.8	126.9			127.2	125.4	127.3									
		Total Asset Replacement												**150.3**	**133.1**	**132.7**			**147.4**	**129.6**	**127.3**									
		Electric Vehicle Charging Infrastructure												**3.6**	**3.7**	**3.2**			**3.7**	**3.2**	**3.3**									
		Beautification												**4.4**	**4.8**	**4.9**			**4.8**	**4.8**	**4.9**									
		Total Gross Sustaining Capital												**235.2**	**191.1**	**197.5**			**193.8**	**190.9**	**182.4**									
		Distribution Total																												
		Total Gross Growth Capital												**307.3**	**362.6**	**333.7**			**326.6**	**331.5**	**333.7**									
		Total Gross Sustaining Capital												**235.2**	**191.1**	**197.5**			**193.8**	**190.9**	**182.4**									
		Less: Contributions in Aid of Construction												(157.2)	(159.3)	(157.5)			(158.4)	(159.4)	(161.2)									
		Total												**385.4**	**394.5**	**373.6**			**362.0**	**362.9**	**354.9**									

Note A: ISA is in the fiscal year following the ISD because of a 3 month span between project in-service and finalization of the in-service additions by Finance.
Note B: This project was approved directly to Implementation and the Definition Phase Activities were completed under the overall Program Management.

Notes:
(1) All information provided is current as of January 1, 2021.
(2) Some projects that are in-service or forecast to be in-service at the end of fiscal 2022 may have trailing expenditures that result in capital additions in the Test Period. These expenditures and associated capital additions have been aggregated and included in the line item "Programs and Projects Less than $5M".
(3) Project / Program dollars are generally capitalized starting either in the feasibility stage of Identification phase or in the Definition phase.
(4) Forecast ISD is the expected in-service date for the project.
(5) Start Date of Construction is the Implementation Approval Date. For projects in Definition, the Start Date of Construction is the forecast Implementation Approval Date.
(6) Definition Approval Date is the fiscal year that the project received Definition phase approval.
(7) Implementation Approval $ is the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation.
(8) Pre-Implementation phases are: Future, Identification and Definition. Refer to Appendix N, Section 2.7 for further discussion on pre-Implementation phases. Pre-Implementation cost estimates are provided where an engineering estimate is available. N/A indicates that an engineering estimate is not yet available, or that the project is in Implementation phase.
(9) Authorized Amount is the 'Authorized' total capital cost of the project.
(10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation.
(11) An extension is a project that expands the service area or capacity of a utility plant or system, in accordance with paragraph 13 of BC Hydro's 2018 Capital Filing Guidelines filed with the BCUC on January 17, 2020.
(12) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate, or in accordance with BCUC Decision and Order G-47-18 and directive 29 of BCUC Decision and Order G-246-20.

Use of To Be Determined (TBD):
For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD), Start Date of Construction and Extension Project, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule and cost. As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start of Construction Date are generally only provided for projects in the Definition phase and later phases. For Extension Projects, TBD has been provided where both extension and non-extension alternatives are being investigated.

Appendix I - F2023-F2025 RRA - Technology

Projects greater than $2 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F23-F25) as at January 1, 2021 (1), (2)

$ Million

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F20	Capital Addition Actual F21	Capital Addition Forecast F22	Capital Addition Forecast F23	Capital Addition Forecast F24	Capital Addition Forecast F25	Capital Expenditure Actual F20	Capital Expenditure Actual F21	Capital Expenditure Forecast F22	Capital Expenditure Forecast F23	Capital Expenditure Forecast F24	Capital Expenditure Forecast F25	Extension Project, Y=Yes, N=No (11)	Current or Potential Application (12)	Appendix J Reference	Technology Strategy & 5 Year Plan (Appendix O) Business Outcome Reference	Appendix K Reference	Program of Projects (Y/N) (or Related Projects)	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
		Manage Compliance and Security																														
		Projects Over $2 million																														
1	T002623	NERC CIP-13	Sustaining	Identification	F2023	TBD	TBD	TBD	TBD	N/A	0.1	-	-	-	3.5	-	-	-	-	2.5	1.1	-	-	No			Resilient and Secure IT and OT Systems	N/A	N	Mandatory	11	N/A
2	T002718	Enterprise MRS Compliance Management System	Sustaining	Initiation	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	2.9	-	-	-	-	0.4	2.5	-	-	No			Resilient and Secure IT and OT Systems	N/A	N	Mandatory	11.5	N/A
3	T001744	Time Based Rates	Sustaining	Identification	F2022	TBD	TBD	TBD	TBD	N/A	0.1	-	-	-	4.4	-	-	-	-	1.8	2.6	-	-	No			Resilient and Secure IT and OT Systems	N/A	N	Prioritization	11	N/A
4	T001935	Privileged Access Management	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	3.0	-	-	-	-	0.8	2.3	-	-	No			Resilient and Secure IT and OT Systems	N/A	N	Prioritization	11	N/A
5	T002612	SIEM Subscription License Acquisition	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	3.2	-	-	3.4	-	-	3.4	-	-	3.4	No			Resilient and Secure IT and OT Systems	N/A	N	Prioritization	10	N/A
6	T002613	Network Product License Acquisition	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	-	4.3	-	-	-	-	-	4.3	-	No			Resilient and Secure IT and OT Systems	N/A	N	Prioritization	0	N/A
7	T001930	Corporate Firewalls Refresh	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	2.5	-	-	-	-	2.3	0.2	-	-	No			Resilient and Secure IT and OT Systems	N/A	N	Prioritization	11	N/A
		Subtotal - Projects over $2 million													16.3	4.3	3.4				8.5	4.3	3.4									
		Programs over $2 million (Recurring Capital)																														
		Subtotal - Programs over $2 million													2.0	2.0	-				1.0	2.0	-									
		Projects and Programs less than $2 million													5.6	4.1	5.8				5.6	4.1	7.6	No								
		Subtotal - Management Compliance and Security													**23.8**	**10.4**	**9.2**				**15.1**	**10.4**	**11.0**									
		Manage Risk and Sustain Productivity																														
		Projects over $2 million																														
8	T001379	SAP S/4HANA Upgrade	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	-	-	-	-	-	-	-	-	7.0	No	Potential Section 44.2	Page 185	Resilient and Secure IT and OT Systems	N/A	N	Prioritization	10	N/A
9	T002360	Human Capital Management (HCM) Foundation	Sustaining	Initiation	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	2.8	-	-	-	-	0.4	2.4	-	-	No			Optimized back-office processes	N/A	N	Prioritization	10	N/A
10	T002061	SAP Business Warehouse (BW) Upgrade	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	4.5	-	-	-	-	4.0	0.5	-	-	No			Enhanced data access and business intelligence	N/A	N	Prioritization	10	N/A
11	T001397	Contact Centre Technology Foundation Refresh	Sustaining	Identification	F2022	TBD	TBD	TBD	TBD	N/A	0.1	-	-	-	-	23.6	-	-	-	5.8	13.3	4.5	-	No	Potential Section 44.2	Page 176	Optimized customer service interactions	N/A	N	Prioritization	11	N/A
12	T001877	Primary GIS Platform Upgrade	Sustaining	Definition	F2023	F2021	F2021	TBD	TBD	N/A	1.6	-	-	-	3.9	-	-	-	0.4	2.3	1.2	0.1	-	No			Resilient and Secure IT and OT Systems	N/A	N	Prioritization	10	N/A
13	T002258	SAP Customer Front End Replacement	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	-	8.7	-	-	-	0.7	4.0	4.0	-	No			Resilient and Secure IT and OT Systems	N/A	N	Prioritization	11	N/A
14	T002085	Advanced Metering System Software Upgrade	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	-	2.9	-	-	-	-	2.2	0.7	-	No			Resilient and Secure IT and OT Systems	N/A	N	Prioritization	10.5	N/A
15	T002036	Energy Management System (EMS) Upgrade	Sustaining	Definition	F2023	F2021	F2021	TBD	TBD	N/A	3.9	-	-	-	12.4	-	-	0.3	3.2	6.3	2.5	-	-	No	Potential Section 44.2	Page 179	Resilient and Secure IT and OT Systems	N/A	N	Prioritization	11	N/A
16	T002321	Primary Data Centre Network Refresh	Sustaining	Initiation	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	8.0	-	-	-	-	2.8	5.2	-	-	No			Resilient and Secure IT and OT Systems	N/A	N	Prioritization	10.5	N/A
17	T002317	Backup Data Centre Network Refresh	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	-	4.0	-	-	-	-	2.0	2.0	-	No			Resilient and Secure IT and OT Systems	N/A	N	Prioritization	10	N/A
18	T002324	Operations Data Centre Network Refresh	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	-	2.0	-	-	-	-	1.0	1.0	-	No			Resilient and Secure IT and OT Systems	N/A	N	Prioritization	10	N/A
19	T002483	Windows Server Upgrade	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	2.0	-	-	-	-	-	2.0	-	-	No			Resilient and Secure IT and OT Systems	N/A	N	Prioritization	10	N/A
20	T001072	Data Centre Backup	Sustaining	Identification	F2021	TBD	TBD	TBD	TBD	N/A	0.0	-	-	0.9	4.3	-	-	-	0.1	0.8	4.3	-	-	No		Page 184	Resilient and Secure IT and OT Systems	N/A	Y (1072, 2678, 2679)	Prioritization	10	N/A
21	T002678	Data Centre Backup Sustainment	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	2.2	-	-	-	-	-	2.2	-	-	No			Resilient and Secure IT and OT Systems	N/A	1072, 2678, 2679	Prioritization	10.5	N/A
22	T002679	Data Centre Backup Sustainment	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	-	1.6	-	-	-	-	-	1.6	-	No			Resilient and Secure IT and OT Systems	N/A	1072, 2678, 2679	Prioritization	10.5	N/A
23	T002692	Physical Security Network Transition	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	-	4.0	-	-	-	-	2.0	1.8	-	No			Resilient and Secure IT and OT Systems	N/A	N	Prioritization	11	N/A
24	T002073	EAS Hardware Upgrade	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	-	3.0	-	-	0.3	-	0.2	2.6	0.3	No			Resilient and Secure IT and OT Systems	N/A	N	Prioritization	10	N/A
25	T002202	Corporate Telephony Replacement	Sustaining	Identification	F2023	TBD	TBD	TBD	TBD	N/A	0.2	-	-	4.2	-	-	-	-	0.0	1.9	2.3	-	-	No		Page 183	Resilient telecommunications networks	N/A	Y (2202, 2669)	Prioritization	11	N/A
26	T002669	Corporate Telephony Replacement	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	0.8	0.8	0.8	-	-	-	0.8	0.8	0.8	No		Page 183	Resilient telecommunications networks	N/A	2202, 2669	Prioritization	11	N/A
27	T002318	Regional site infrastructure refresh	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	2.5	-	-	-	-	1.5	1.0	-	-	No			Resilient and Secure IT and OT Systems	N/A	N	Prioritization	10	N/A
28	T002676	Meter Data Management System Upgrade	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	-	2.9	-	-	-	-	-	2.9	-	No			Resilient and Secure IT and OT Systems	N/A	N	Prioritization	0	N/A
		Subtotal - Projects over $2 million													43.2	53.6	0.8				49.0	22.1	8.1									
		Programs over $2 million (Recurring Capital)																														
		Subtotal - Programs over $2 million													30.3	20.9	17.5				19.2	20.2	17.5									
		Projects and Programs less than $2 million													19.9	17.7	26.9				19.9	18.1	31.0	No								
		Subtotal - Manage Risk and Sustain Productivity													**93.4**	**92.2**	**45.2**				**88.1**	**60.3**	**56.5**									
		Enhance Business Capability																														
		Projects over $2 million																														
29	T001035	Dam Safety Information System (DSIS)	Sustaining	n	F2024	F2021	F2020	5.0	2023-08-30	N/A	4.4	-	-	-	3.3	-	-	0.3	0.2	1.5	1.1	0.3	-	No			Enhanced dam safety systems	N/A	N	Committed	10	N/A
30	T000625	Vehicle and Equipment Telemetry	Sustaining	Definition	F2022	F2021	F2021	TBD	TBD	N/A	0.4	-	-	-	-	2.5	-	0.2	0.2	0.4	0.9	0.9	-	No			Optimized supply chain function	N/A	N	Prioritization	9	N/A
31	T002016	Advanced Distribution Management System (ADMS) (formerly ID 901654)	Sustaining	Definition	F2023	F2021	F2021	TBD	TBD	N/A	5.0	-	-	-	11.0	-	-	-	1.6	6.9	2.3	0.1	-	No		Page 174	Distribution grid management	N/A	N	Prioritization	10	N/A
32	T002122	Stations Work Management	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	-	22.0	-	-	-	5.0	8.0	9.0	-	No	Potential Section 44.2	Page 186	Operations work planning and scheduling	N/A	N	Prioritization	N/A	1
33	T002549	Distribution Design Modernization	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	-	-	-	23.0	-	-	-	3.0	10.0	10.0	No	Potential Section 44.2	Page 178	Enhanced engineering design	N/A	N	Prioritization	N/A	1
		Subtotal - Projects over $2 million													14.3	24.5	23.0				15.3	20.2	10.0									
		Programs over $2 million (Recurring Capital)																														
		Subtotal - Programs over $2 million													-	-	-				-	-	-									
		Projects and Programs less than $2 million													6.5	6.6	7.2				6.6	5.2	9.1	No								
		Subtotal - Enhance Business Capability													**20.8**	**31.0**	**30.2**				**21.9**	**25.5**	**19.1**									
		Risk Adjustment													(19.0)	(14.0)	(6.0)				(16.0)	(8.0)	-									
		Total													**119.0**	**119.5**	**78.6**				**109.2**	**88.2**	**86.6**									

Notes:

(1) All information provided is current as of January 1, 2021.
(2) Some projects that are in-service or forecast to be in-service at the end of fiscal 2022 may have trailing expenditures that result in capital additions in the test period. These expenditures and associated capital additions have been aggregated and included in the line item "Programs and Projects Less than $5M".
(3) Project / Program dollars are generally capitalized starting either in the feasibility stage of Identification phase or in the Definition phase.
(4) Forecast ISD is the expected in-service date for the project.
(5) Start Date of Construction is the Implementation Approval Date. For projects in Definition, the Start Date of Construction is the forecast Implementation Approval Date.
(6) Definition Approval Date is the fiscal year that the project received Definition phase approval.
(7) Implementation Approval $ is the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation.
(8) Pre-Implementation phases are: Future, Identification and Definition. Refer to Appendix N Section 2.7 for further discussion on pre-Implementation phases. Pre-Implementation cost estimates are provided where an engineering estimate is available. N/A indicates that an engineering estimate is not yet available, or that the project is in Implementation phase.
(9) Authorized Amount is the 'Authorized' total capital cost of the project.
(10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation.
(11) An extension is a project that expands the service area or capacity of a utility plant or system, in accordance with paragraph 13 of BC Hydro's 2018 Capital Filing Guidelines filed with the BCUC on January 17, 2020.
(12) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate, or in accordance with BCUC Decision and Order G-47-18 and directive 29 of BCUC Decision and Order G-246-20.

Use of To Be Determined (TBD):
For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD), Start Date of Construction and Extension Project, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very
different project scope, schedule and cost. As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start of Construction Date are generally only provided for projects in the Definition phase and later phases. For Extension Projects, TBD has been provided where both extension and non-extension alternatives are being investigated.

Appendix I - F2023-F2025 RRA - Properties
Projects greater than $5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F23-F25) as at January 1, 2021 (1), (2)
$ Million

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7) (11)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8), (11)	Authorized Amount (9)	Capital Addition Actual F20	Capital Addition Actual F21	Capital Addition Forecast F22	Capital Addition Forecast F23	Capital Addition Forecast F24	Capital Addition Forecast F25	Capital Expenditure Actual F20	Capital Expenditure Actual F21	Capital Expenditure Forecast F22	Capital Expenditure Forecast F23	Capital Expenditure Forecast F24	Capital Expenditure Forecast F25	Extension Project, Y=Yes, N=No (11)	Current or Potential Application (12)	Appendix J Reference	Name of Strategy, Plan or Study to which Project is Linked	Appendix K Reference	Program of Projects (Y/N)	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
1	P201703	Chilliwack Field Building Redevelopment	Sustaining	Definition	F2026	TBD	F2017	-	-	N/A	-	-	-					0.2	-0.9	-	10.0	5.0	11.0	No		Page 187	N/A	N/A	N/A	For Prioritization	10.0	N/A
2	P201704	Materials Classification Facility Building Redevelopment	Sustaining	Implementation	F2024	F2021	F2017	46.9	F2024	N/A	46.9	-	-	2.3		44.6		1.30	3.0	8.9	24.9	6.2	-	No		Page 189	N/A	N/A	N/A	For Prioritization	9.5	N/A
3	P201901	Kamloops Field Building Redevelopment	Sustaining	Identification	TBD	TBD	TBD	-	-	TBD	-	-	-						-	-	2.5	3.5	19.5	No	Potential Section 44.2	Page 191	N/A	N/A	N/A	For Prioritization	9.5	N/A
4	P201902	North Vancouver Field Building Redevelopment	Sustaining	Definition	F2026	TBD	F2021	-	-	N/A	-	-	-						0.9	1.5	9.0	18.5	13.0	No		Page 193	N/A	N/A	N/A	For Prioritization	9.5	N/A
5	P202001	Campbell River II Field Building Redevelopment	Sustaining	Definition	F2026	TBD	F2021	-	-	N/A	-	-	-						0.8	2.5	4.5	13.5	14.0	No		Page 195	N/A	N/A	N/A	For Prioritization	9.5	N/A
6	P202012	Dunsmuir Roof & 18th Floor HVAC Upgrade	Sustaining	Identification	TBD	TBD	TBD	-	-	TBD	-	-	-				5.0		-	-	-	1.0	4.0	No		-	N/A	N/A	N/A	For Prioritization	11.0	N/A
7	P202101	Duncan Field Building Redevelopment	Sustaining	Identification	TBD	TBD	TBD	-	-	TBD	-	-	-		5.0				-	0.3	6.0	4.0	6.5	No		Page 197	N/A	N/A	N/A	For Prioritization	9.5	N/A
8	P202102	Mica Staff Accommodations Building Redevelopment	Sustaining	Identification	TBD	TBD	TBD	-	-	TBD	-	-	-	-	-	-	14.5	-	0.5	0.5	2.0	8.0	3.5	No		-	N/A	N/A	N/A	For Prioritization	9.0	N/A
9	P202103	Prince Rupert Field Building Redevelopment	Sustaining	Future	TBD	TBD	TBD	-	-	TBD	-	-	-		6.6				-	1.5	5.1	-	-	No		-	N/A	N/A	N/A	For Prioritization	9.5	N/A
10	P202114	Edmonds Operations Centre Truck Bay Upgrade	Sustaining	Definition	F2023	TBD	F2021	-	-	N/A	-	-	-		7.9				0.0	2.5	5.4	-	-	No		-	N/A	N/A	N/A	For Prioritization	9.0	N/A
11	P202115	Surrey LMS Truck Bay Upgrade	Sustaining	Definition	F2023	TBD	F2020	-	-	N/A	-	-	-		5.7				0.2	4.0	1.5	-	-	No		-	N/A	N/A	N/A	For Prioritization	9.5	N/A
12	P202201	Queen Charlotte City Field Building Redevelopment	Sustaining	Identification	TBD	TBD	TBD	-	-	N/A	-	-	-			7.1				0.5	2.0	4.6	-	No		-	N/A	N/A	N/A	For Prioritization	9.0	N/A
13	P202202	Cranbrook Field Building Redevelopment	Sustaining	Identification	TBD	TBD	TBD	-	-	TBD	-	-	-						-	0.3	1.0	5.3	11.5	No		Page 199	N/A	N/A	N/A	For Prioritization	9.5	N/A
14	P202401	Fort St. John Field Building Redevelopment	Sustaining	Future	TBD	TBD	TBD	-	-	TBD	-	-	-						-	-	-	1.0	2.0	No		-	N/A	N/A	N/A	For Prioritization	9.0	N/A
		Projects Less Than $5 Million	Sustaining	Multiple	Multiple	Multiple	Multiple	Multiple	Multiple	Multiple	Multiple	-	-	41.9	16.8	21.1	14.1	53.8	48.1	34.8	18.8	18.0	7.3	No			N/A	N/A	N/A	For Prioritization	Multiple	N/A
		Portfolio risk adjustment										-	-	(5.7)	(9.3)	(6.9)	(7.9)			(5.7)	(9.3)	(6.9)	(7.9)									
Total												-	-	**36.2**	**27.7**	**21.3**	**6.2**	**55.3**	**52.6**	**51.5**	**83.4**	**81.7**	**92.3**									

Notes:
(1) Information provided is current as of the established 'Currency Date' which is January 1, 2021.
(2) Some projects that are in-service or forecast to be in-service at the end of fiscal 2021 may have trailing expenditures that result in capital additions in the Test Period. These expenditures and associated capital additions have been aggregated and included in the line item "Programs and Projects Less than $5M".

(3) Project / Program dollars are generally capitalized starting either in the feasibility stage of Identification phase or in the Definition phase.
(4) Forecast ISD is the expected in-service date for the project.
(5) Start Date of Construction is the Implementation Approval Date. For projects in Definition, the Start Date of Construction is the forecast Implementation Approval Date.
(6) Definition Approval Date is the fiscal year that the project received Definition phase approval.
(7) Implementation Approval $ is the Authorized total capital cost of the project when it was first approved by BC Hydro for Implementation.
(8) Pre-Implementation phases are: Future, Identification and Definition. Refer to Appendix S-2, pp. 6-65 to 6-67 for further discussion on pre-Implementation phases. Pre-Implementation cost estimates are provided where an engineering estimate is available. N/A indicates that an engineering estimate is not yet available, or that the project is in Implementation phase.

(9) Authorized Amount is the Authorized total capital cost of the project.

(10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation.
(11) An extension is a project that expands the service area or capacity of a utility plant or system, in accordance with paragraph 13 of BC Hydro's 2018 Capital Filing Guidelines filed with the BCUC on January 17, 2020.
(12) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate, or in accordance with BCUC Decision and Order G-47-18 and directive 29 of BCUC Decision and Order G-246-20.

Use of To Be Determined (TBD):
For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD), Start Date of Construction and Extension Project, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule and cost. As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start of Construction Date are generally only provided for projects in the Definition phase and later phases. For Extension Projects, TBD has been provided where both extension and non-extension alternatives are being investigated.

Appendix I - F2023-F2025 RRA - Other
Projects greater than $5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F23-F25) as at January 1, 2021 (1), (2)
$ Million

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F21	Capital Addition Forecast F22	Capital Addition Forecast F23	Capital Addition Forecast F24	Capital Addition Forecast F25	Capital Expenditure Actual F21	Capital Expenditure Forecast F22	Capital Expenditure Forecast F23	Capital Expenditure Forecast F24	Capital Expenditure Forecast F25	Extension Project, Y=Yes, N=No (11)	Current or Potential Application (12)	Appendix J Reference	Name of Strategy, Plan or Study to which Project is Linked	Appendix K Reference	Program of Projects (Y/N)	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
Other Capital																														
		Other Technology																												
1	900864	Mobile Radio Optimization - LM	Sustaining	Implementation	2023	F2016	F2016	9.5	F2019	N/A	9.5	-	-	11.6	-	-	1.3	5.3	0.2	-	-	N			N/A	N/A	N	Committed		
2		**Fleet/Vehicles**	Sustaining	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	26.8	29.9	42.0	39.6	27.5	31.4	28.3	42.0	39.6	27.5									
		Business Support - Other																												
3	FC-00392	Material Management - Oil Management Operating Infrastructure	Sustaining	Definition	F2024	TBD	F2019		TBD	TBD	3.6	0	0	0	19.1	0	1.4	2.5	11.1	2.9	0	N			N/A	N/A	N	For Prioritization		
		Add: Programs and Projects Less than $5M												28.3	32.2	29.3			27.0	33.6	30.1									
		Total												**28.3**	**51.3**	**29.3**			**38.1**	**36.5**	**30.1**									
		Total Fleet / Other Technology/Other												**81.9**	**90.9**	**56.8**			**80.3**	**76.1**	**57.6**									

Notes:
(1) All information provided is current as of January 1, 2021.
(2) Some projects that are in-service or forecast to be in-service at the end of fiscal 2022 may have trailing expenditures that result in capital additions in the Test Period. These expenditures and associated capital additions have been aggregated and included in the line item "Programs and Projects Less than $5M".
(3) Project / Program dollars are generally capitalized starting either in the feasibility stage of Identification phase or in the Definition phase.
(4) Forecast ISD is the expected in-service date for the project.
(5) Start Date of Construction is the Implementation Approval Date. For projects in Definition, the Start Date of Construction is the forecast Implementation Approval Date.
(6) Definition Approval Date is the fiscal year that the project received Definition phase approval.
(7) Implementation Approval $ is the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation.
(8) Pre-Implementation phases are: Future, Identification and Definition. Refer to Appendix S-2, pp. 6-65 to 6-67 for further discussion on pre-Implementation phases. Pre-Implementation cost estimates are provided where an engineering estimate is available. N/A indicates that an engineering estimate is not yet available, or that the project is in Implementation phase.
(9) Authorized Amount is the 'Authorized' total capital cost of the project.
(10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation.
(11) An extension is a project that expands the service area or capacity of a utility plant or system, in accordance with paragraph 13 of BC Hydro's 2018 Capital Filing Guidelines filed with the BCUC on January 17, 2020.
(12) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate, or in accordance with BCUC Decision and Order G-47-18 and directive 29 of BCUC Decision and Order G-246-20.

Use of To Be Determined (TBD):
For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD), Start Date of Construction and Extension Project, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule and cost. As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start of Construction Date are generally only provided for projects in the Definition phase and later phases. For Extension Projects, TBD has been provided where both extension and non-extension alternatives are being investigated.

Appendix I - F2023-F2025 RRA - Site C
Projects greater than $5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F23-F25) as at January 1, 2021 (1), (2)
$ Million

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F20	Capital Addition Actual F21	Capital Addition Forecast F22	Capital Addition Forecast F23
Site C Project															
1	1115778	Site C	Growth	Implementation	F2025 (Unit 1)	F2016	F2015	7,575.2	F2024 (Unit 1)	N/A	16,000.0	12.9	220.9	-	-

	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
	Capital Addition Forecast F24	Capital Addition Forecast F25	Capital Expenditure Actual F20	Capital Expenditure Actual F21	Capital Expenditure Forecast F22	Capital Expenditure Forecast F23	Capital Expenditure Forecast F24	Capital Expenditure Forecast F25	Extension Project, Y=Yes, N=No (11)	Current or Potential Application (12)	Appendix J Reference	Name of Strategy, Plan or Study to which Project is Linked	Appendix K Reference	Program of Projects (Y/N)	Category (Mandatory, Committed, and for Prioritization)	Risk Score	Value Score
Site C Project																	
1	-	13,977.3	1,619.1	1,725.0	2,789.5	2,708.3	1,754.9	1,043.2	Y	Exempt per Clean Energy Act, sec. 7(1)	Page 201	N/A	N/A	N	Committed		

*****this will be confusing as we were approved in June with a new budget of approximately $15,240.0, but the data date is April 1, 2021**

Notes:
(1) Information provided is current as of the established 'Currency Date' which is April 1, 2021.
(2) Some projects that are in-service or forecast to be in-service at the end of fiscal 2021 may have trailing expenditures that result in capital additions in the Test Period. These expenditures and associated capital additions have been aggregated and included in the line item "Programs and Projects Less than $5M".
(3) Project / Program dollars are generally capitalized starting either in the feasibility stage of Identification phase or in the Definition phase.
(4) Forecast ISD is the expected in-service date for the project (as at the Currency Date).
(5) Start Date of Construction is the Implementation Approval Date. For projects in Definition, the Start Date of Construction is the forecast Implementation Approval Date.
(6) Definition Approval Date is the fiscal year that the project received Definition phase approval.
(7) Implementation Approval $ is the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation.
(8) Pre-Implementation phases are: Future, Identification and Definition. Refer to Appendix S-2, pp. 6-65 to 6-67 for further discussion on pre-Implementation phases. Pre-Implementation cost estimates are provided where an engineering estimate is available. N/A indicates that an engineering estimate is not yet available, or that the project is in Implementation phase.
(9) Authorized Amount is the 'Authorized' total project cost including the present value of future operating payments and costs deferred to the Site C Regulatory Account as of as of July 1, 2021.
(10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation.
(11) An extension is a project that expands the service area or capacity of a utility plant or system, in accordance with paragraph 13 of BC Hydro's 2018 Capital Filing Guidelines filed with the BCUC on January 17, 2020.
(12) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate as of the Currency Date (See Note 1), or in accordance with BCUC Decision and Order G-47-18 and directive 29 of BCUC Decision and Order G-246-20.

Use of To Be Determined (TBD):
For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD), Start Date of Construction and Extension Project, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule and cost. As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start of Construction Date are generally only provided for projects in the Definition phase and later phases. For Extension Projects, TBD has been provided where both extension and non-extension alternatives are being investigated.

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix J

Capital Expenditures > $20 million

Appendix J Summaries

Appendix J, Attachment 1 provides descriptions for capital projects and programs of projects with planned capital expenditures or additions in the test period, with planned total capital expenditures greater than $20 million.

Consistent with our Previous Application, the Appendix J project summaries include information on the key drivers of the capital projects. In this application these key drivers are aligned with the consequence types identified in BC Hydro's Corporate Risk Matrix.

The Corporate Risk Matrix identifies the following "consequence types" or risk impacts:

- Safety – This includes the safety of both the public and BC Hydro workers;
- Environmental – This includes impacts to habitats and species;
- Financial Loss (Financial) – This includes direct financial loss or costs;
- Reputational – This includes responses from the public, media and public officials as well as impacts to projects, programs, plans and operations as a result of these responses; and
- Reliability – This includes customer reliability (hours lost per event) and reliability of supply.

The Appendix J capital project summaries identify which of these five categories of consequence types are the key drivers for investments that are risk driven.

Also consistent with our Previous Application, the Appendix J summaries provide Implementation Phase risks and risk treatment for those projects in the Implementation Phase with risks identified as high severity and/or high probability consequences, or a combination of moderate severity and probability consequences. The assessment is based on BC Hydro’s Project Delivery Risk Matrix (derived from the Corporate Risk Matrix).

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix J

Attachment 1

Description of Capital Projects and Programs of Projects

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Generation			
Hydroelectric			
Growth			
N/A			
Redevelopment / Rehabilitation			
N/A			
Dam Safety			
Bridge River 2 - Strip and Recoat Penstock 2 Interior	1	Page 7	Pages 11 and 5
Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)	2	Page 15	Pages 14 and 5
Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment	3	Page 48	Page 31
Revelstoke Replace Downie Slide Instrumentation	4	N/A	Page 39
Comox - Puntledge Flow Control Improvements	5	Page 17	Page 37
John Hart Dam Seismic Upgrade	6	Page 32	Pages 3 and 22
Ladore Spillway Seismic Upgrade	7	Page 44	Pages 3 and 29
Mica - Intake Gantry Crane Refurbishment	8	N/A	Page 33
Strathcona Upgrade Discharge	9	Page 78	Pages 3 and 47
W.A.C. Bennett Dam Seal Low Level Outlets	10	Page 89	Page 18
Alouette - Environmental Flow Discharge Upgrade and LLO Sealing	11	N/A	Page 7
Alouette Improve Headworks & Surge Tower Seismic Stability	12	Page 1	Page 7
Ash River Extend Life of Steel Penstock	13	Page 3	Pages 9 and 5
Bridge River 1 - Improve Slope Drainage	14	N/A	Page 11
Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior	15	Page 7	Pages 11 and 5
GMS – Install Further Instrumentation for Monitoring Embankment Condition	16	N/A	Page 18
Hugh Keenleyside - Spillway and Low Level Outlets Concrete Upgrade	17	Page 30	Page 20

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Hugh Keenleyside - Fire Protection System Upgrade	18	N/A	Page 18
La Joie - Dam Improvements	19	Page 40	Pages 27 and 1
Mica - Discharge Facilities Seismic and Reliability Upgrades	20	Page 55	Page 33
Terzaghi - Spillway Chute Access Improvement	21	N/A	Page 11
Various Sites - Reservoir Booms Replacement - F2020	22	Page 83	N/A
W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates	23	Page 86	Page 18
Bridge River 1 - Penstock Concrete Foundation Refurbishment	24	Page 5	Page 11
Cheakamus - Dam Improvements	25	Page 13	Page 14
G.M. Shrum - Intake Operating Gate and Intake Maintenance Gate Refurbishment	26	Page 27	Page 18
G.M. Shrum - Intake Operating Gate Hydraulic Upgrade	27	Page 27	Page 18
Hugh Keenleyside - Cranes Upgrade	28	N/A	Page 20
Kootenay Canal - Canal Concrete Liner Joints Upgrade	29	Page 35	Page 25
Lake Buntzen 1 - Penstock Interior Restoration	30	Page 50	Page 31
Mica - Little Chief Inclinometers Installation	31	N/A	Page 33
Ruskin - Left Abutment Slope Sinkhole Remediation	32	N/A	N/A
Seton - Canal Flow Control Structure Upgrade	33	Page 71	Pages 41 and 1
Sugar Lake - Dam Abutments Upgrade	34	N/A	Page 45
Terzaghi - Dam Instrumentation Upgrade	35	N/A	Page 11
Terzaghi - Low Level Discharge Reliability Improvement	36	Page 81	Pages 11 and 1
Various Sites - Probabilistic Seismic Hazard Model Update	37	N/A	N/A
Various Sites - Spillway Gate Standby Power Improvements	38	Page 85	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Sustaining - Other			
Cheakamus Replace Units 1 and 2 Turbine Inlet Valves	39	N/A	Page 14
G.M. Shrum G1 to 10 Control System Upgrade	40	Page 20	Page 18
G.M. Shrum Upgrade HVAC System	41	Page 22	Page 18
Hugh Keenleyside Recoat Navlock Gates	42	N/A	Page 20
Hugh Keenleyside Replace Service Water Piping	43	N/A	Page 20
Jordan - Upgrade Governor & PRV Controls	44	N/A	Page 23
Mica - Reactor 5RX3 Replacement	45	Page 52	Page 33
Mica Modernize Controls	46	Page 57	Page 33
Mica Replace Units 1 to 4 Generator Transformers	47	Page 59	Page 33
Mica Upgrade 600V Circuit Breakers	48	Page 63	Page 33
Mica Upgrade HVAC System	49	Page 65	Page 33
Peace Canyon - 600V Circuit Breaker Upgrades	50	N/A	Page 35
Puntledge Recoat Interior and Exterior of Steel Penstock	51	Page 67	Pages 37 and 5
Revelstoke Replace Fire Alarm System	52	N/A	Page 39
Seven Mile - Replace T1 Transformer	53	N/A	Page 43
Seven Mile Upgrade Powerhouse Crane Controls	54	N/A	Page 43
Various - Water License Renewal	55	N/A	N/A
Wahleach Recoat Penstock (Interior and Exterior)	56	N/A	Pages 49 and 5
Wahleach Refurbish Generator	57	Page 91	Page 49
Waneta U3 Life Extension	58	Page 93	N/A
Bridge River 1 Replace Units 1-4 Generators / Governors	59	Page 9	Page 11
Various Sites - Cutler Hammer Exciters Upgrade	60	N/A	Page 16
Whatshan - Governor Replacement	61	N/A	Page 51
Ash River - Upgrade Communication Systems	62	N/A	Page 9
GMS - Unwatering System Refurbishment	63	Page 29	Page 18
Kootenay Canal - U1 - U4 Generators Refurbishment	64	Page 37	Page 25
Kootenay Canal Modernize Controls	65	Page 38	Page 25
Lake Buntzen 1 - Generator Replacement	66	Page 46	Page 31
LDR - Upgrade Communication Systems	67	N/A	Page 29

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Mica - U1 - U4 Circuit Breaker and Iso-phase Bus Replacement	68	Page 54	Page 33
Peace Canyon - U1 - U4 Exciter Replacement	69	N/A	Page 35
Revelstoke - U1 - U4 Stator Replacement	70	Page 69	Page 43
Seton - Upgrade Unit	71	Page 73	Page 41
Various Facilities Replace Water Level Gauges	72	N/A	N/A
Ash River - Generator Replacement	73	N/A	Page 9
Bridge River 2 - Transformer Replacement	74	N/A	N/A
G.M. Shrum - Pauwels Transformer Life Extension	75	N/A	Page 18
G.M. Shrum - Physical Security Upgrade - Phase I	76	Page 24	Page 18
G.M. Shrum - U5 Generator Refurbishment	77	Page 25	Page 18
G.M. Shrum - U6 Generator Refurbishment	78	Page 26	Page 18
Kootenay Canal - Fire Detection and Alarm System Replacement	79	N/A	Page 25
Ladore - Unit Transformer Upgrade	80	N/A	Page 29
La Joie - Governor Pressure Regulating Valve Replacement	81	Page 42	Page 27
Mica - Crash-rated Gate Replacement	82	N/A	N/A
Mica - Nagle Creek Crossing Infrastructure Refurbishment	83	N/A	Page 33
Mica - U1 - U2 Turbine Overhaul	84	Page 61	Page 33
Peace Canyon - High and Low Pressure Piping Replacement	85	N/A	Page 35
Peace Canyon - Powerhouse, Intake and Tailrace Crane Upgrades	86	N/A	Page 35
Revelstoke - Intake and Tailrace Gantry Crane Upgrades	87	N/A	Page 39
Seven Mile - U1 - U3 Turbine Upgrade	88	Page 76	Page 43
Seven Mile - U1 - U4 Controls Upgrade	89	Page 75	Page 43
Various Sites - PCB Lighting Remediation (F2022-F2024)	90	N/A	N/A
Diesel			
N/A			

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Thermal			
Burrard - Modify for Post Generation Operations	91	N/A	Page 13
Fort Nelson - U2 Steam Turbine Overhaul	92	N/A	Page 17
Transmission			
Growth Capital Expenditures			
Regional System Reinforcement			
Bridge River Transmission Project	1	Page 104	Page 75
North Montney Region - Electrification	2	Page 136	Page 95
West Kelowna Transmission and Westbank Upgrade Projects	3	Page 162	Page 96
West End - Substation Construction and System Reinforcement	4	Page 160	Page 77
Peace to Kelly Lake - Remedial Action Scheme Upgrade	5	N/A	N/A
East Vancouver - Substation Construction	6	Page 110	Page 77
Sunshine Coast - Transmission Reinforcement	7	Page 151	N/A
Bulk System Reinforcements			
Cranbrook 5L94 - Line Reactor Replacement	8	N/A	N/A
Lower Mainland - Capacitive and Reactive Power Reinforcement	9	Page 123	Page 76
Prince George to Terrace Capacitors Project	10	Page 146	N/A
Station Expansion & Modification			
Capilano Substation Upgrade	11	Page 106	Page 80
Clayburn Substation Upgrade	12	Page 108	Page 53
Mount Lehman Substation Upgrade	13	Page 128	Page 53
Horne Payne - Feeder Section Addition	14	Page 114	Page 87
Generator Interconnections			
N/A			
Transmission Load Interconnections			
Customer IPID - 901580	15	N/A	N/A
Customer IPID - 901573	16	N/A	N/A
Customer IPID - 901851	17	N/A	N/A
Customer IPID - 901581	18	N/A	N/A
Customer IPID - 901940	19	N/A	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Customer IPID - 902121	20	N/A	N/A
Customer IPID - 901943	21	N/A	N/A
Customer IPID - 901938	22	N/A	N/A
Sustaining Capital Expenditures			
Circuit Breakers			
SPG Metalclad Switchgear Replacement	23	Page 149	Page 92
Kimberley to Marysville - Substation Relocation	24	Page 119	Page 60
Pemberton - Substation Rebuild	25	N/A	Page 60
Maple Ridge - Feeder Section 60 Series Refurbishment	26	Page 127	Page 60
Other Power Equipment			
American Creek - Capacitor Protection Control Upgrade	27	N/A	Page 56
Barnard 50/60 Feeder Section Replacement	28	Page 100	Page 73
Hundred Mile House T1/T2 EOL Replacement	29	N/A	Page 69
Jordan River - Switchyard Upgrade	30	Page 115	Page 69
SC Excitation Systems Upgrade - VIT/KLY	31	N/A	Page 68
Natal Sub - NTL 60-138 kV Rebuild	32	Page 130	Page 85
Sandspit Substation Replacement	33	N/A	Page 97
Ah-sin-heek - Substation Replacement	34	N/A	Page 97
Bridge River - T4 Transformer Replacement	35	Page 102	Page 69
Kennedy - 5CX1 Controls Replacement (Emergency)	36	N/A	N/A
Oldfield - Substation Feeder Section Upgrade	37	N/A	Page 89
Peace to Kelly Lake - Stations Sustainment	38	Page 140	Pages 59, 66 and 67
VIT & KLY Hydrogen Gas Sys - Safety Upgrade	39	N/A	Page 68
KI1 60Kv Renovation, 4Kv Decommission & Control Room	40	Page 117	Page 82
Mainwaring Station Upgrade	41	Page 125	Page 84
Newell Substation Upgrade	42	Page 134	Page 86
Patricia - Substation Upgrade	43	Page 138	Page 91
Peace Region to Kelly Lake - Reactor Replacement (Phase 2)	44	Page 142	Page 67
Kelly Lake - Reactor Installation	45	N/A	Page 68

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Norgate - Substation Bypass	46	N/A	Page 80
Peace Region to Kelly Lake - Reactor Replacement (Phase 3)	47	Page 142	Page 67
Peace Region to Kelly Lake - Reactor Replacement (Phase 4)	48	Page 142	Page 67
Telegraph Creek - Substation Replacement	49	N/A	Page 97
Protection and Control			
GMS Substation - Control Systems Upgrade	50	N/A	Page 56
NERC CIP V5 Compliance at Medium Impact T&D Stations	51	Page 132	Page 56
Control PLC984 and RTU Replacement (WSN)	52	N/A	Page 56
Various Sites - NERC CIP-003v7 Implementation	53	Page 156	Page 56
Stations Auxiliary Equipment			
Joseph Creek (JOE) Substation Upgrade	54	N/A	Page 97
Canal Flats - Substation Wood Pole Replacement	55	N/A	Page 97
Skookumchuck - Substation Wood Pole Replacement	56	N/A	Page 97
Cathedral Square - Substation HVAC Upgrade	57	N/A	Page 59
Lumby #2 - Substation Wood Pole Replacement	58	N/A	Page 97
Port Alberni - Substation Refurbishment	59	Page 144	Page 59
Prevost - Substation Control Building Upgrade	60	N/A	Page 59
Woss - Substation Wood Pole Replacement	61	N/A	Page 97
Stations Risk Mitigation			
Oil Spill Containment - F17/F18 (ALZ / MDN)	62	N/A	Page 64
Stations Seismic Upgrade -F16/17 (9 Stations)	63	N/A	N/A
Project IPID - 900766: Jeune Landing - Substation Acquisition and Upgrade	64	N/A	N/A
Telecommunications			
Vancouver Island Radio System	65	Page 154	Page 71
Various Sites - Mountain Top 1603 Replacement	66	N/A	Page 71
System Wide – Bulk Electric System Telecom Equipment Replacement	67	Page 152	Page 71
Various Sites - Telecom Analog Private Line Replacement	68	N/A	Page 55

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Fraser Valley - Telecom System Reliability Upgrade	69	N/A	Page 79
Various Sites - MPLS Core Router Upgrade	70	N/A	Page 71
Various Sites – Telecom Transport Network Resiliency Enhancement	71	Page 158	Page 93
Cable Sustainment			
2L146 - Cable Replacement	72	Page 96	Page 63
Coquitlam - 2L51 Partial Replacement	73	N/A	Page 63
Gulf Islands - Transmission Reinforcement	74	Page 112	Page 63
South Fraser Transmission Relocation Project	75	Page 148	N/A
O/H Lines Life Extension			
5L063 Telkwa Relocation	76	Page 98	N/A
Long Span Crossing Refurbishment - F17/F18 (1L37)	77	Page 121	Page 58
O/H Lines Risk Mitigation			
1X387AMX – Kitsault Transmission Line Hazard Mitigation	78	N/A	N/A
2L003 and 2L049 – Transmission Line Crossing Seismic Upgrade (Second Narrows)	79	Page 95	Page 74
ROW Sustainment			
N/A			
Third Party Requested Transmission Line Relocations			
Customer IPID - 901563	80	N/A	N/A
Customer IPID - 901807	81	N/A	N/A
Distribution			
Growth Capital Expenditures			
Customer Driven			
Customer IPID DY-1545	1	N/A	N/A
Customer IPID DY-0347	2	N/A	N/A
Customer IPID 901955	3	N/A	N/A
Customer IPID 902127	4	N/A	N/A
Customer IPID 902128	5	N/A	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
System Expansion and Improvement			
LOH 12F56, 12F62 Voltage Conversion Preparation (LM-BBY-082)	6	N/A	N/A
Mount Lehman New Feeder to Offload Balfour, Mount Lehman and Gloucester Feeders (FV-ABT-042)	7	N/A	N/A
Two new CBN Feeders to Offload SMW (LM-FVE-606)	8	N/A	N/A
Glenmore Voltage Conversion (LM-NSC-088)	9	N/A	N/A
Norgate - Offload NOR loads to NVR feeders (LM-NSH-074)	10	N/A	N/A
North Vancouver - Offload NVR loads to LYN new feeders (LM-NSH-075)	11	N/A	N/A
Oldfield (OFD) Voltage Conversion 12 to 25kV (NI-NEW-273)	12	N/A	N/A
Three Fleetwood feeders to offload McLellan (FV-FVW-723)	13	N/A	N/A
Three new MLE Feeders to offload CBN (LM-FVE-607)	14	N/A	N/A
Downtown Vancouver - Voltage Conversion Preparation for Customer Vaults (LM-VAN-210)	15	N/A	N/A
Fleetwood - Distribution Feeder Ductbank and Feeder Installation (FV-FVW-023)	16	N/A	N/A
Fleetwood - Distribution Feeder Ductbank and Feeder Installation (FV-FVW-805)	17	N/A	N/A
Langley - MLN 25F32 and MLN 25F33 Offload (FV-FVW-741)	18	N/A	N/A
Tofino - New LBH 25F54 Feeder Installation To Offload LBH 25F52 (VI-PAL-010)	19	N/A	N/A
Vancouver Island - Saltspring 25F61 Cable Extension to North Pender Island (VI-GUL-005)	20	Page 170	N/A
Sustaining Capital Expenditures			
System Expansion and Improvement			
Downtown Vancouver - Underground Murrin Feeders to Eliminate H-Frames in Gastown	21	Page 165	N/A
H-Frame Elimination - Chinatown	22	Page 167	N/A
Mission - Feeder 25F51 Tie (FV-ABT-039)	23	N/A	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
100 Mile House - Relocate Sections of Transmission along Hendrix Road (SI-HMH-002)	24	N/A	N/A
Gwillim Microwave - Power Supply Upgrade	25	N/A	N/A
Asset Replacement			
Various Sites - LED Street Light Conversion	26	Page 172	Page 99
Electric Vehicle Charging Infrastructure			
N/A			
Beautification			
N/A			
Technology			
Manage Compliance and Security			
Projects Over $2 million			
NERC CIP-13	1	N/A	N/A
MRS Compliance System Project - SigmaFlow	2	N/A	N/A
Time Based Rates	3	N/A	N/A
Privileged Access Management	4	N/A	N/A
Splunk Subscription License Acquisition	5	N/A	N/A
Cisco Enterprise License Acquisition	6	N/A	N/A
Corporate Firewalls Refresh	7	N/A	N/A
Manage Risk and Sustain Productivity			
Projects Over $2 million			
SAP S/4HANA Upgrade	8	Page 185	N/A
Human Capital Management (HCM) Foundation	9	N/A	N/A
SAP Business Warehouse on HANA Migration	10	N/A	N/A
Contact Centre Technology Foundation Refresh	11	Page 176	N/A
GE Smallworld GIS Platform Upgrade	12	N/A	N/A
SAP Customer Front End Replacement	13	N/A	N/A
Openway Migration	14	N/A	N/A
Energy Management System (EMS) 3.x Upgrade	15	Page 179	N/A
Primary Data Centre Network Refresh	16	N/A	N/A
Backup Data Centre Network Refresh	17	N/A	N/A
Operations Data Centre Network Refresh	18	N/A	N/A
Windows Server Upgrade	19	N/A	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Data Centre Backup	20	Page 184	N/A
Data Centre Backup Sustainment	21	N/A	N/A
Data Centre Backup Sustainment	22	N/A	N/A
Physical Security Network Transition	23	N/A	N/A
EAS Greenplum Hardware Upgrade	24	N/A	N/A
Corporate Telephony Replacement	25	Page 183	N/A
Corporate Telephony Replacement	26	Page 183	N/A
Regional site infrastructure refresh	27	N/A	N/A
Meter Data Management System Upgrade	28	N/A	N/A
Projects and Programs less than $2 million			
N/A			
Enhance Business Capability			
Projects over $2 million			
Dam Safety Information System (DSIS)	29	N/A	N/A
Vehicle and Equipment Telemetry	30	N/A	N/A
Advanced Distribution Management System (ADMS)	31	Page 174	N/A
Stations Work Management	32	Page 186	N/A
Distribution Design Modernization	33	Page 178	N/A
Programs over $2 million (Recurring Capital)			
N/A			
Projects and Programs less than $2 million			
N/A			
Properties			
Chilliwack Field Building Redevelopment	1	Page 187	N/A
Materials Classification Facility Building Redevelopment	2	Page 189	N/A
Kamloops Field Building Redevelopment	3	Page 191	N/A
North Vancouver Field Building Redevelopment	4	Page 193	N/A
Campbell River II Field Building Redevelopment	5	Page 195	N/A
Dunsmuir Roof & 18th Floor HVAC Upgrade	6	N/A	N/A
Duncan Field Building Redevelopment	7	Page 197	N/A
Mica Staff Accommodations Building Redevelopment	8	N/A	N/A
Prince Rupert Field Building Redevelopment	9	N/A	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Edmonds Operations Centre Truck Bay Upgrade	10	N/A	N/A
Surrey LMS Truck Bay Upgrade	11	N/A	N/A
Queen Charlotte City Field Building Redevelopment	12	N/A	N/A
Cranbrook Field Building Redevelopment	13	Page 199	N/A
Fort St. John Field Building Redevelopment	14	N/A	N/A
Business Support Other			
Other Technology			
Mobile Radio Optimization - LM	1	N/A	N/A
Fleet/Vehicles			
Fleet/Vehicles	2	N/A	N/A
Business Support - Other			
Material Management - Oil Management Operating Infrastructure	3	N/A	N/A
Site C Project			
Site C	1	Page 201	N/A

<table>
<tr><td colspan="1">Investment Planning ID:
G000011</td><td colspan="2">Project Name:
Alouette Improve Headworks & Surge Tower Seismic Stability</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• Chapter 6, page 6-89
• Appendix I - Generation, line 5; Appendix J, page 7; Appendix K, page 3
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-25
• Appendix I - Generation, line 4</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to address seismic deficiencies of the Alouette water conveyance system to ensure it can be relied upon to pass reservoir inflows to Stave Lake after a large earthquake event.</td></tr>
<tr><td colspan="3">Key Drivers:
• Safety
• Environmental
• Financial Loss
• Reputational</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Alouette Dam is classified as an “Extreme” consequence dam based on the BC Dam Safety Regulation. As such the expected seismic performance is for no uncontrolled release for the Maximum Design Earthquake (MDE) with an annual exceedance frequency of once in 10,000 years. A seismic performance deficiency investigation of the dam and power tunnel was completed in 2011, and it concluded that the spillway would be damaged in the MDE and could not be relied upon to pass the inflow of water afterward. Spilling water through the damaged spillway could lead to its failure and an uncontrolled release of water from the reservoir, with significant risk to life, financial loss, environmental consequences and reputational impact.
Should the spillway not be available following a MDE, the only means to control the reservoir elevation would be to use the Alouette power tunnel and adit to allow a controlled discharge into Stave Lake. The seismic assessment indicated that in the event of a MDE, damage to structures associated with the power tunnel is expected, which could result in the inoperability of the power tunnel and/or adit. As such, a decision was made to upgrade the power tunnel and related structures, to ensure safe and reliable operation of the Alouette Dam after a MDE.</td></tr>
</table>

1 Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives:	
BC Hydro is considering three alternatives: i. **Do nothing:** defer, either temporarily or permanently, the correction of the seismic deficiencies, ii. **Upgrade the power tunnel and related structures**, and iii. **Demolish and replace the structures associated with the power tunnel**. Alternative ii is the current leading alternative to achieve the project objectives. The project is currently in the Feasibility Design Stage. BC Hydro is consulting First Nations and conducting stakeholder engagement on construction period impacts to the reservoir and Alouette River flows to determine the preferred means of implementing the project.	
Project Impacts and Benefits: • Improve safety by addressing seismic deficiencies of the power tunnel and related structures, so that this water conveyance system can be relied upon to pass reservoir inflows to Stave Lake after a MDE. • Reduce potential for fatalities, financial loss, environmental consequences and reputational impact due to an uncontrolled release of water from Alouette Reservoir, in the event of a MDE.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: N/A	

Investment Planning ID:	Project Name:	
G000042	Ash River Extend Life of Steel Penstock	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Identification	**Filing Reference:** F20-F21 RRA: • Chapter 6, page 6-95 • Appendix I - Generation, line 50; Appendix K, pages 5 and 31 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-27 • Appendix I - Generation, line 43	

Description:

The purpose of this project is to ensure safe and reliable operation of the steel penstock at the Ash River Generating Facility and extend the life of the penstock, by addressing the active corrosion which is resulting in loss of metal thickness and strength on the interior and exterior of the steel penstock, and three tunnel portal steel liners.

Key Drivers:

- Environmental
- Reliability
- Safety
- Financial

Issues Being Addressed:

The Ash River Generating Station is categorized as a Strategic facility based on BC Hydro's Facility Asset Plans. It is downstream of Elsie Lake which is impounded by the Elsie Lake Dam.

The internal coating system on the steel penstock and tunnel portal liners at Ash River are failing with significant defects throughout the coated surfaces and signs of corrosion. The external steel penstock shows small isolated areas of coating failure. The Asset Health Rating for the penstock is Poor. Addressing the penstock internal coating system failure will extend its useful life. If no action is taken, the penstock surfaces will continue to corrode. Over time, this will undermine the structural integrity and safety of the penstock. The penstock would then need to be replaced when it is no longer safe to operate.

Discussion of Alternatives:

The following alternatives were evaluated:

i. **Defer recoating;**

ii. **Fully Strip and recoat the steel penstock interior and the tunnel portal liner surfaces, and only partially over-coat the steel penstock exterior;**

iii. **Fully Strip and recoat the steel penstock interior and the tunnel portal liner surfaces;**

iv. **Fully Strip and recoat the steel penstock interior and exterior and the tunnel portal liners.**

Alternative ii was selected as the Single Viable Alternative, as it was lowest cost alternative that would meet the requirements for safety, reliability and extended penstock life. Alternative i was not considered viable due to the risk that, if left for too long, the steel penstock may require replacement as the window of

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">opportunity for re-coating will have passed. Alternative iii was not considered viable, because if the exterior over-coating is deferred the condition will worsen to the point that over-coating is no longer possible, and a full external strip and re-coat (at higher cost) would be required in the future. Alternative iv was not considered viable as it would achieve the same outcome of extended penstock life, yet at a significantly higher cost.</td></tr>
<tr><td colspan="2">• Project Impacts and Benefits:
• Improve equipment reliability and safety.
• Extend penstock life.
• Reduce potential for fatalities, financial loss, and reputational damage due to uncontrolled release of water from the reservoir.</td></tr>
<tr><td>Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="2">Additional Information:
N/A</td></tr>
</table>

Investment Planning ID: G004327	Project Name: Bridge River 1 - Penstock Concrete Foundation Refurbishment	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** New	

Description:

The purpose of this project is to ensure safe and reliable operation of the four steel penstocks at the Bridge River 1 Generating Facility for another 40 years by refurbishing the concrete penstock foundations that have deteriorated over time.

Key Drivers:

- Reliability
- Safety
- Financial

Issues Being Addressed:

There are four steel penstocks at Bridge River 1 that supply power to four 50 MW generating units. Inspections have found that the fixed concrete foundations and the sliding concrete foundations in some locations for each penstock have visible defects such as cracking and are undermined due to erosion. The foundations are also buried in many sections due to accumulation of rockfall debris which prevents a full inspection from being completed. It is assumed that the observed defects in the visible foundations would be of a similar level in the buried sections.

The identified damaged sections, as well as the potential damage to uninspected sections, present an increased risk of failure of the concrete foundation. Failure of the concrete foundation could lead to penstock failure that would impact the switchyard, powerhouse, staff on site, CN Rail, and the local community.

Discussion of Alternatives:

BC Hydro is considering three alternatives:

i. **Do nothing** and monitor the condition;

ii. **Replace** penstocks and foundations; and

iii. **Refurbish** concrete foundations and replace or add retaining walls to control future rockfall.

Alternative iii. was selected as the single viable alternative as it would address safety and reliability objectives with the lowest life cycle cost. Alternative i. would not address the risk to the overall penstock, nor does it reduce the impacts a failure could have on personnel, infrastructure, and equipment downstream of the penstocks. Alternative ii. would be a magnitude higher cost than refurbishment and is not warranted as the penstock steel is in good condition and planned to be recoated.

Project Impacts and Benefits:

- Improve worker and public safety by addressing deteriorating condition of the penstock concrete foundations that could lead to a penstock failure.
- Reduce potential for fatalities, financial loss and reputational damage, due to an uncontrolled release of water from the reservoir.
- Improve equipment reliability and safety.
- Extend asset life.

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.
Additional Information: N/A	

<table>
<tr><td colspan="1">Investment Planning ID:
G000485</td><td colspan="2">Project Name:
Bridge River 1 – Strip and Recoat Penstocks 1-4 Interior</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• Chapter 6, page 6-95
• Appendix I - Generation, line 51; Appendix J, page 49; Appendix K, page 7 and 31
• BCUC 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-27
• Appendix I - Generation, line 45
• BCUC IR 1.45.2</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to ensure safe and reliable operation of the four steel penstocks at the Bridge River 1 (BR1) Generating Facility and extend the life of the penstocks, by addressing the active corrosion of the interior and exterior which is resulting in loss of metal thickness and strength.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Safety
• Financial
• Environmental</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Bridge River Generating Station is classified as a Key Facility in accordance with BC Hydro’s Facility Asset Plans. It is located downstream of Carpenter Lake, which is impounded by Terzaghi Dam. The internal and external coating systems on all four penstocks at BR1 are failing with significant defects throughout the coated surfaces. The Asset Health Rating for the penstocks is unsatisfactory and they are showing signs of coating failure and corrosion. Recoating the penstocks will extend their useful life.
If no action is taken, the penstock surfaces will corrode. Over time, this will undermine the structural integrity and safety of the penstocks. The penstocks would then need to be replaced when they are no longer safe to operate.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">

Discussion of Alternatives:

BC Hydro considered three alternatives:

i. **Defer Recoating;**

ii. **Replace penstocks;**

iii. **Strip and recoat penstocks.**

Alternative iii, strip and recoat penstocks, was selected as the Single Viable Alternative as the only alternative that would meet the requirements for safety and reliability and to extend the penstock life. Alternative i was not considered viable due to the risk that, if left too long, the steel penstock may require replacement as the window of opportunity for re-coating will have passed. Alternative ii was not considered viable due to the much higher cost to achieve the same outcome as recoating.

</td></tr>
<tr><td colspan="2">

Project Impacts and Benefits:

- Improve equipment reliability and safety.
- Extend penstock life.
- Reduce financial loss by carrying out essential stripping and recoating work during already planned outages for the BR1 Generator Replacement Project.
- Reduce potential for fatalities, financial loss, and reputational damage due to an uncontrolled release of water from the reservoir.

</td></tr>
<tr><td>

Project Implementation Phase Risk:

Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.

</td><td>

Risk Treatment:

To be determined when the project reaches Implementation.

</td></tr>
<tr><td colspan="2">

Additional Information:

N/A

</td></tr>
</table>

Investment Planning ID: G000776	Project Name: Bridge River 1 Replace Units 1-4 Generators / Governors	
Forecast Capital Cost: $333 million to $202 million	**Forecast In-Service Date:** Fiscal 2031	**Start Date of Construction:**[1] Fiscal 2024
Development Phase: Definition	**Filing Reference:** BC Hydro 2014 Annual Report to the BCUC • Attachment to Section 8 – Part 2 Appendix I, page line 139 Appendix J, page 2 F17-F19 RRA • Appendix I, Appendix J, page 28 • BCUC IRs 1.70.3, 2.249.8, 2.260.4 • BCOAPO IR 1.36.1 F20-F21 RRA: • Chapter 6, page 6-95 • Appendix I - Generation, line 52; Appendix J, page 50; Appendix K, page 7 • BCOAPO IR 1.62.1 PUBLIC Attachment 1 • BCUC IR 1.115.2 • BCUC IR 1.133.1 Confidential F22 RRA: • Chapter 6, page 6-27 • Appendix I - Generation, line 44 • BCUC IR 1.45.2	
Description: The purpose of the project is to improve generation reliability of the Bridge River 1 Generating Facility Units 1 to 4 generators and related equipment, and to provide reliable water conveyance capacity within the Bridge River system.		
Key Drivers: • Reliability • Environmental • Reputational		
Issues Being Addressed: The four generators and related equipment in the Bridge River 1 Generating Facility have an Asset Health Rating of either Unsatisfactory or Poor. Unit 4 was re-wound in 1977 but was de-rated after a stator winding failure during testing in 2011. The de-rating of Unit 4 restricts the water flow through the unit, limiting water conveyance capabilities.		

1 Start Date of Construction is the Implementation Approval Date.

In addition to the loss in operating capability due to the de-rating of Bridge River 1 Unit 4, the operating regime for both Bridge River 1 and 2 has been impacted by a Dam Safety requirement from February 2015 to lower the maximum elevation of the upstream Downton Reservoir to manage LaJoie Dam seismic safety risks. This change in operations means there is 50 per cent less storage in Downton Reservoir, resulting in increased seasonal inflow to Carpenter Reservoir. Reduced capability to divert water from Carpenter Reservoir to Seton Lake, via the Bridge River generating stations, has increased the likelihood and magnitude of spills from Terzaghi Dam to the Lower Bridge River beyond the Water Use Plan Order (**WUP Order**) targets for annual average flows and those same targets set forth in settlement agreements with the St'át'imc Nation. BC Hydro has been, and currently is, operating under a variance to our WUP Order, approved by the Comptroller of Water rights (February 16, 2017).

Discussion of Alternatives:

Four alternatives were evaluated during the Identification Phase:

i. **Do Nothing:** maintain the existing units and replace the generators and other related components upon failure;

ii. **Rewind** the generator stators and replace or refurbish other components, as needed, to ensure each unit can maintain its original 50 MW rating;

iii. **Refurbish** the generators and replace the exciters and governors to match the current capacity of the turbines, and operate within the limitations of the existing physical plant and constraints of the existing WUP Order; and

iv. **Replace** the generators, exciters and governors to match the current capacity of the turbines and operate within the limitations of the existing physical plant and constraints of the existing WUP Order.

Alternative iv, Replace the generators, exciters and governors, was selected as the leading alternative because it offers improvements to generator reliability and water management capabilities. Compared to alternatives i, ii, and iii this alternative maximizes unit reliability, minimizes impacts to the environment and St'át'imc Nation interests, enhances BC Hydro's relationship with the St'át'imc Nation, minimizes cost and cost risks, and minimizes overall safety risks.

Project Impacts and Benefits:

- Improve generation reliability by replacing the Units 1 to 4 generators and related equipment.
- Provide reliable water conveyance capacity within the Bridge River system.
- Reduce the likelihood and magnitude of spills from Terzaghi Dam to Lower Bridge River, in order to minimize potential effects on fish, riparian habitat, and First Nations values.
- Maintain BC Hydro's relationship with the St'at'imc Nation.
- Reduce potential reputational impact due to spill events.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase	To be determined when the project reaches Implementation.

Additional Information:

BCUC Order No. G-246-20 directed BC Hydro to file a joint CPCN application for this project and the Bridge River Transmission Project.

The planning level estimate for this project is over $100 million. $326.3 million to $207.1 million is the latest Pre-Implementation Cost Estimate that is reflected in the project's CPCN application.

Investment Planning ID: G000489	**Project Name:** Bridge River 2 – Strip and Recoat Penstock 2 Interior	
Forecast Capital Cost: $35.3 million	**Forecast In-Service Date:** Fiscal 2023	**Start Date of Construction:**[1] Fiscal 2021
Development Phase: Implementation	**Filing Reference:** F20-F21 RRA: • Appendix I: Generation - line 53 • Appendix K: pages 7 and 31 • Chapter 6, page 6-97 • BCOAPO IR 1.59.1 • BCOAPO IR 1.62.1 PUBLIC Attachment 1 • BCUC IR 1.133.1 Confidential F22 RRA: • Chapter 6, page 6-27 • Appendix I - Generation, line 46 • BCUC IR 1.43.1 • BCUC IR 1.46.3	

Description:

The purpose of this project is to ensure safe and reliable operation of Penstock 2 at the Bridge River 2 (**BR2**) Generating Facility and extend the life of the penstock, by addressing the active corrosion of the interior which is resulting in loss of metal thickness and strength.

Key Drivers:

- Reliability
- Safety
- Financial

Issues Being Addressed:

The Bridge River Generating Station is classified as a 'key' facility according to BC Hydro's Facility Asset Plans. It is located downstream of Carpenter Lake, which is impounded by Terzaghi Dam. The internal coating system on Penstock 2 at BR2 is failing with significant defects identified throughout the coated surface; there are signs of coating failure and corrosion. The Asset Health Rating for the penstock is rated as Unsatisfactory. Stripping and recoating the penstock will extend its useful life.

If no action is taken, the interior penstock surface will corrode. Over time, this will undermine the structural integrity and safety of the penstock. The penstock would then need to be replaced when it is no longer safe to operate.

Discussion of Alternatives:

BC Hydro considered three alternatives:

i. **Defer Recoating**;
ii. **Complete a Full or Partial penstock replacement**, and
iii. **Strip and recoat the penstock interior during a planned outage**.

[1] Start Date of Construction is the Implementation Approval Date.

Alternative iii, strip and recoat the penstock interior during a planned outage, was selected as the preferred alternative as it was the lowest cost alternative that would meet the requirements for safety and reliability and extend the life of the asset. Alternative i was not considered viable due to the risk that, if left for too long, the steel penstock may require replacement as the window of opportunity for re-coating will have passed. Alternative ii was not considered viable due to the much higher cost.	
Project Impacts and Benefits: • Improve equipment reliability and safety. • Extend penstock life. • Reduce potential for fatalities, financial loss, and reputational damage due to an uncontrolled release of water from the reservoir.	
Project Implementation Phase Risk: The work will be carried out on a steep slope and inside a penstock. As such, there is significant risk to worker safety due to fall hazards and confined space issues.	**Risk Treatment:** The project will use unmanned robotic technology to complete many of the most hazardous tasks such as water jetting, abrasive blasting and relining the interior of the penstock.
Additional Information: N/A	

Investment Planning ID: G000052	Project Name: Cheakamus - Dam Improvements	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** New	

Description:

The purpose of this project is to address internal erosion and seismic deficiencies of the Cheakamus Dam so that this facility can be relied upon for passing floods and post-earthquake operation.

Key Drivers:

- Safety
- Reputational
- Environmental
- Financial

Issues Being Addressed:

The Cheakamus Dam is classified as an Extreme consequence dam. Investigations have identified that various components of the dam – notably spillway piers, several zones of the earthfill dam and a retaining wall at the contact between the concrete and earthfill dams – could fail or deform excessively when subjected to earthquake ground motions expected to occur at the site once every 500 to 1,500 years. This is less than the target "withstand" of one in 10,000 years for an Extreme consequence dam.

In addition, the earthfill dam has a history of seepage along the downstream slope above the downstream rockfill berm when reservoir levels are high. In response, the normal maximum reservoir elevation was lowered by 1.45 m from its original elevation to reduce the risk of internal erosion of the upper dam core. Under a sustained extreme flood, however, the higher reservoir elevation that would result could initiate internal erosion in the dam core.

Failure of the dam could lead to uncontrolled release of water from the reservoir, potentially resulting in fatalities, reputational risks, environmental damage, and significant financial loss.

Discussion of Alternatives:

BC Hydro is considering four alternatives:

i. **Do nothing:** defer, either temporarily or permanently, the correction of the deficiencies of the dam;

ii. **Decommission the dam**;

iii. **Decrease downstream consequences**: lower the reservoir, protect inundation areas, and implement an early warning system; and

iv. **Upgrade the dam, spillway and retaining wall:** This may include a seismic upgrade of the spillway, treatments to strengthen existing soils, construction of a downstream berm to buttress the slopes, and anchoring of Retaining Wall No. 1.

Project Impacts and Benefits:

- Improve public safety by addressing seismic deficiencies and internal erosion potential of the Cheakamus Dam, so that this facility can be relied upon for passing floods and post-earthquake operation.
- Reduce potential financial loss and reputational impact due to an uncontrolled release of water from the reservoir, in the event of a Maximum Design Earthquake or Probable Maximum Flood.

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.
Additional Information: There is an ongoing Deficiency Investigation at Cheakamus Dam to update flood parameters and conduct a performance assessment of the dam and discharge structures. The scope of the Dam Improvements project may be affected by the findings of the Deficiency Investigation.	

<table>
<tr><td colspan="1">Investment Planning ID:
G000057</td><td colspan="2">Project Name:
Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)</td></tr>
<tr><td>Forecast Capital Cost:
$23.5 million</td><td>Forecast In-Service Date:
Fiscal 2023</td><td>Start Date of Construction:[1]
Fiscal 2019</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
BC Hydro’s F2014 Annual Report to the BCUC:
• Attachment to Section 8 – Part 2
Appendix I, line 120
Appendix J, page 4
F17-F19 RRA:
• Appendix I, Appendix J page 30,
• BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1
F20-F21 RRA:
• Chapter 6, page 6-95
• Appendix I - Generation, line 33; Appendix J, page 38; Appendix K, page 10 and 31
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
• BCUC IR 1.133.1 Confidential
F22 RRA:
• Chapter 6, page 6-27
• Appendix I - Generation, line 23
• BCUC IR 1.46.3</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to ensure safe and reliable operation of Cheakamus penstocks 1 and 2 and extend the life of the penstocks and tunnel by addressing the active corrosion which is resulting in loss of metal thickness and strength on the exterior and interior steel surfaces, and steel lined tunnel.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Safety
• Financial
• Environmental</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Cheakamus Generating Station is categorized as a ‘Strategic” facility according to BC Hydro’s Facility Asset Plans. The Station is located downstream of Daisy Lake which is impounded by the Cheakamus Dam.
The protective coatings on the exterior and interior of the Cheakamus steel penstocks and steel tunnel liner are exhibiting signs of coating failure. The Asset Health Rating is rated as Unsatisfactory.
Without recoating, the extent of corrosion will increase to the the point where recoating is no longer an option and a penstock replacement is required. Over time, continued corrosion will impact the structural integrity of the steel material, impacting the penstock’s ability to reliably and safely convey water to the Cheakamus generating units.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives:	
BC Hydro considered four alternatives: i. **Do Nothing and Monitor**; ii. **Strip and Recoat Exterior Surface of Steel Penstocks**; iii. **Strip and Recoat Exterior and Interior Surfaces of Steel Penstocks**; and iv. **Complete Replacement of Steel Penstocks**. Alternative iii, strip and recoat exterior and interior surfaces of steel penstocks, was selected as the preferred alternative as it would address safety and reliability objectives and extend the penstock life. Alternative i or Alternative ii would not deliver a significant overall penstock life extension because corrosion of the uncoated and unprotected steel penstock sections would not be achieved. Loss of steel would persist, potentially undermining the structural integrity of the penstock, which are considered high pressure vessels conveying significant volumes of water and are key water passage components used for generation. Penstock failures may cause extensive damage to the Cheakamus Generating Station. Alternative iv was not selected as it would be too costly compared to Alternative iii which also addresses the project objectives.	
Project Impacts and Benefits: • Improve equipment reliability and safety. • Extend asset (penstock and steel tunnel) life. • Reduce potential for fatalities, financial loss, and reputational damage due to an uncontrolled release of water from the reservoir.	
Project Implementation Phase Risk: The interior coating work requires power generation outages. The project schedule could extend if the outage windows available to the project are shorter than planned or if the contractor underperforms.The work will be carried out on a steep slope and inside a penstock. As such, there is significant risk to worker safety due to fall hazards and confined space issues.	**Risk Treatment:** Accept – There are escalation clauses within the contract should the work be extended. There will be additional overhead costs that will have to be covered by project contingency.The project will use unmanned robotic technology to complete many of the most hazardous tasks such as water jetting, abrasive blasting and relining the interior of the penstock.
Additional Information: N/A	

Investment Planning ID: G000657	Project Name: Comox – Puntledge Flow Control Improvements	
Forecast Capital Cost: $56.7 million to $33.9 million	**Forecast In-Service Date:** Fiscal 2025	**Start Date of Construction:**[1] Fiscal 2022
Development Phase: Definition	**Filing Reference:** BC Hydro's F2014 Annual Report to the BCUC • Attachment to Section 8 – Part 2 Appendix I, line 109 Appendix J, page 9 F17-F19 RRA: • Appendix I - Generation, line 15, Appendix J page 16 • BCUC IRs 1.70.3,2.249.8, 2.260.4, BCOAPO IR 1.36.1 F20-F21 RRA: • Chapter 6, page 6-98 • Appendix I - Generation, line 8; Appendix J, Page 9; Appendix K, Page 33 • BCOAPO IR 1.62.1 PUBLIC Attachment 1 • BCUC IR 1.133.1 Confidential F22 RRA: • Chapter 6, page 6-25 • Appendix I - Generation, line 14 • BCUC IR 1.53.1	

Description:

The purpose of this project is to improve the ability to manage water conveyance at Comox-Puntledge in a controlled and safe manner.

Key Drivers:

- Safety
- Reliability
- Environmental
- Financial Loss
- Reputational

Issues Being Addressed:

The Comox Dam and downstream Puntledge Diversion facilities are rated as "Extreme" and "Very High" consequence dams, respectively, based on the BC Dam Safety Regulation. The water passing through Puntledge Dam enters one of two parallel watercourses:

- Generation water is conveyed through the power intake and penstock. Most of the water is conveyed through the single turbine to produce power; and
- The balance of the water overflows Puntledge Dam into a public watercourse which is heavily used for recreation, especially in summer.

[1] Start Date of Construction is the Implementation Approval Date.

Appropriate control of both watercourses is imperative for public safety, dam safety, reliable generation and downstream fish migration and habitat. Uncontrolled flows pose a risk to life, and could result in financial loss, environmental and reputational damage.

The principal risk to be managed through this project is the potential for unintended and sudden increases in flows down the Puntledge River that could lead, without warning, to injury or fatality for exposed downstream recreational users. There are a number of deficiencies within the flow control system which could cause such a surge in flow, and these deficiencies are to be addressed within this project.

Discussion of Alternatives:

BC Hydro considered eight alternatives that consisted of various combinations of the following nine “Concept Groups”:

i. **Improve Support for Operational Decisions:** improve the clarity and certainty in making operational decisions to avoid incidents (such as providing additional tools, training, and data collection and monitoring capability to personnel on site);

ii. **Comox Sluiceway Reliability Improvements:** improve the reliability of the gate controls (such as additional protection and controls equipment and improving the current mechanical gate hoist);

iii. **Generation Conveyance Control System Upgrades:** reduce the probability of a malfunction, lack of function, or other error on the equipment and control systems from the Puntledge intake to the powerhouse (such as improvements to intake trashrack, intake operating gate, fish screen, penstock protection, turbine inlet valve, communication monitoring and control);

iv. **Provide Storage Buffer at Puntledge Diversion Dam:** attenuate the impacts of a stoppage of flow by using available storage in the low gradient Puntledge headpond (such as providing control of discharge at Puntledge Dam in real-time and strengthening the diversion);

v. **Comox Dam Safety Upgrades:** reduce the probability of unusual, very rapid flow increases due to right abutment failure (such as addressing concerns with sloughing of the right bank upstream from the sluiceway and with the robustness to resisting overtopping and piping during extreme floods),

vi. **Modify Puntledge Intake Layout:** Reduce the likelihood of flow control failures in the Puntledge intake and fish screens (such as construction of new fish bypass facilities, new intake bays and penstock work);

vii. **Puntledge Powerhouse By-pass:** Provide flow continuity around the powerhouse (such as construction of a new valve with emergency submerged discharge on the upstream side of the powerhouse);

viii. **Restrict Summer Generation:** Reduce flow control risks; and

ix. **Fully Restrict Generation:** Eliminate flow control risks.

The alternative selected is comprised of Concept Groups i, ii and iii above. It was selected as the preferred alternative because it meets the project objectives regarding public safety and because it provides the best balance of flow and incremental risk improvement versus cost to implement. Other combinations of concept groups including ix Fully Restrict Generation are either higher cost than other alternatives that provide an equal or better flow control improvement benefit, or provide less flow control improvement benefit than alternatives of similar cost.

Project Impacts and Benefits:

- Improve safety by addressing uncontrolled flow at Comox-Puntledge, so that safe downstream recreation can continue.
- Reduce potential for fatalities, financial loss and reputational impact due to uncontrolled flow events.
- Provide long-term operability and maintainability at Comox-Puntledge, at a high level of reliability.
- Reduce environmental risk associated with uncontrolled flow impacts on upstream and downstream fish migration and habitat.

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase, further developed during Definition Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.
Additional Information: N/A	

<table>
<tr><td>Investment Planning ID:
G000127</td><td colspan="2">Project Name:
G.M Shrum G1 to 10 Control System Upgrade</td></tr>
<tr><td>Forecast Capital Cost:
$75 million</td><td>Forecast In-Service Date:
Fiscal 2023</td><td>Start Date of Construction:[1]
Fiscal 2016</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
Amended F12-F14 RRA:
• Application: Amended Appendix I, Page 12; Amended Appendix J, pages 101 to 103
BC Hydro's F2014 Annual Report to the BCUC:
• Attachment to Section 8 – Part 2
Appendix I, line 91
Appendix J, page 10
F17-F19 RRA:
• Appendix I, Appendix J page 24,
• BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1
F20-F21 RRA:
• Chapter 6, page 6-95
• Appendix I - Generation, line 26; Appendix J, Page 32; Appendix K, Page 13
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
• BCUC IR 1.133.1 Confidential
F22 RRA:
• Chapter 6, page 6-27
• Appendix I - Generation, line 25</td></tr>
<tr><td colspan="3">Description:
This purpose of this project is to modernize Units 1 to 10 control systems, replace Units 6 to 10 governor control systems, replace Units 9 and 10 exciters, replace the controls for plant auxiliary systems, and replace the control room controls at G.M. Shrum (GMS) Generating Facility.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The GMS Units 6 to 8 governors have an Asset Health Rating of Poor due to the tendency of the analog controls to drift out of calibration, limited technical support, governor frequency control being out of specification during standardized tests, and limited availability of spare parts. The Unit 9 analog governor has an Asset Health Rating of Poor due to the forced outages attributed to the governor, limited technical support and limited spare parts availability. The Unit 10 analog governor, which is from the same manufacturer as Unit 9, has an Asset Heath Rating of Fair.
The GMS Units 9 and 10 Westinghouse Rapcon exciters have analog controls and are based on obsolete technology. Unit 9 has an Asset Health Rating of Fair, and Unit 10 has a rating of Poor. Concerns include component failures, limited availability of spare parts, and limited technical support.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date for all Tranches of this project.

Concerns on all the equipment to be replaced include lack of vendor support due to system age, limited or no availability of spare parts, units drifting off settings due to control deficiencies, and unit outages caused by component failure or mis-operation.

Discussion of Alternatives:

BC Hydro considered three alternatives:

i. **Full-scope**;

ii. **Controls-only scope**; and

iii. **Deferral** - continue to operate GMS (and Peace Canyon) Generating Facility in their current condition

Alternative i, full-scope, was selected as the preferred alternative because it minimizes the total outage time and avoids the need to design and implement interfaces between new and old technology. The project is partitioned into three tranches of work, with a separate approval for each tranche.

- Tranche 1: Units 1 to 5 controls and plant Local Area Network (completed);
- Tranche 2: Units 6 to 10 controls, Units 6 to 10 governor controls, and Units 9 to10 exciters (in Implementation); and
- Tranche 3: Spillway, switchyard and intake controls, and GMS control room (in Implementation).

This approach allows lessons learned on earlier tranches to be adopted in subsequent tranches. More importantly, each tranche will be estimated and scheduled shortly before it enters Implementation Phase, based on current supplier and market understanding, and avoids a commitment to cost and schedule targets over a decade in the future.

It was recognized that due to the long duration of the project, control improvements could be available during the course of the project. BC Hydro has implemented a strategy of evaluating the benefits of any changes in controls, and if warranted, adopts a new control approach both prospectively and retrospectively, updating completed work to match any newly adopted designs. This strategy balances the advantages of new or improved technology with the benefits of standardization across all units in the plant.

Alternative ii was not selected due to inefficiencies with executing the three scope packages (controls 1-10, exciters 9-10, and governors 6-10) as separate projects in the areas of project delivery and engineering, outage coordination, and ability to avoid stranded costs. Alternative iii was not selected due to inferior risk reduction and economic benefits as compared to Alternative i.

Project Impacts and Benefits:

- Allows both local and remote operation of both GMS and the Peace Canyon Generating Facilities.
- Governors on Units 6 to10 and exciters on Units 9 to10 will be new, improving availability of both spares and vendor support.
- New controls and control room will improve the operators' situational awareness and ability to respond to problems.

Project Implementation Phase Risk:	**Risk Treatment:**
There is a risk that the equipment currently deployed by the Generating Operational Asset Architecture Logic standard will not provide the functionality to support the required plant control room alarm management features	This is being avoided by deploying a Supervisory Control and Data Acquisition control packages for the new plant control room design with the intention of including this alarm management capability in the Generating Operational Asset Architecture Logic standard

Additional Information:

N/A

<table>
<tr><td>Investment Planning ID:
G000114</td><td colspan="2">Project Name:
G.M. Shrum Upgrade HVAC System</td></tr>
<tr><td>Forecast Capital Cost:
$27 million</td><td>Forecast In-Service Date:
Fiscal 2024</td><td>Start Date of Construction:[1]
Fiscal 2021</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I,
• BCUC IRs 1.70.3. 2.249.8, 2.260.4, BCOAPO IR 1.36.1

F20-F21 RRA:
• Chapter 6, page 6-95
• Appendix I - Generation, line 35; Appendix J, page 40; Appendix K, page 13
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
• BCUC IRs 1.116.8; 1.133.1 Confidential; 2.253.1; 2.253.2; 2.253.3; 2.253.4

F22 RRA:
• Chapter 6, page 6-27
• Appendix I - Generation, line 33
• BCUC IR 1.46.3
• CEC IR 1.37.1</td></tr>
<tr><td colspan="3">Description:
The purpose of the G.M. Shrum Upgrade HVAC System project is to address degrading conditions of the Heating, Ventilation and Air Conditioning (HVAC) system at the G.M. Shrum (GMS) Generating Facility.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Safety</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The project will address the reliability risk of forced unit outages due to HVAC system failures. Recent forced outage reports have indicated that heating systems in the Circuit Breaker Buildings may be a contributing cause to improper operation of the unit circuit breakers. In addition, the cooling coils and related piping for the Low Voltage Lead Shaft powerhouse supply fans are nearing end of life and have been a source of water leaks. Although the HVAC system is classified as an ancillary system, it has impacts to the reliable and safe operation of units at the GMS Generating Facility.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
BC Hydro considered three alternatives:
i. Limited Refurbishment of HVAC System;
ii. Modernization of HVAC System; and
iii. Modernization and Selected Upgrades of HVAC System.
Alternative iii, Modernization and Selected Upgrades (upgrade to improve performance of certain components) of the HVAC System, was selected as the preferred alternative as it will meet the project objectives of improving reliability, and reducing worker safety risks. Alternative i was not selected because of the negligible difference between the incremental costs associated to refurbishment</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

compared to Alternative iii with residual reliability, maintainability, and safety risks. Alternative ii was not selected because of lower maintainability, flexibly, safety and energy efficiency than Alternative iii.	
Project Impacts and Benefits: • Improve reliability by reducing outages due to HVAC component failure. • Improve Worker Safety by facilitating safe egress in an emergency situation by pressurizing escape routes and ensuring fresh air is supplied to workers in the underground powerhouse.	
Project Implementation Phase Risk: The HVAC systems work requires multiple outages for different generating units. There is a risk of changes to required planned outages which may result in schedule delay and additional cost.	**Risk Treatment:** The treatment plan is to align the outages with generator maintenance outages to reduce the probability of changes to the planned outages.
Additional Information: N/A	

<table>
<tr><td>Investment Planning ID:
G003302</td><td colspan="2">Project Name:
G.M. Shrum – Physical Security Upgrade – Phase I</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Future</td><td colspan="2">Filing Reference:
New</td></tr>
<tr><td colspan="3">Description:
The purpose of the project is to provide a long-term solution for access control and access management to the G.M. Shrum (GMS) Generating Facility and W.A.C. Bennett Dam (WAC) Dam.</td></tr>
<tr><td colspan="3">Key Drivers:
• Safety
• Financial</td></tr>
<tr><td colspan="3">Issues Being Addressed:
A security assessment conducted at the GMS Generating Facility and WAC Dam facility has identified opportunities to improve physical security of the facility, specifically to address access control. The physical security infrastructure and systems were installed at GMS Generating Facility/ WAC Dam over ten years ago and neither is meeting the current BC Hydro security standards, nor providing cost-effective security controls.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
BC Hydro is considering three alternatives:
i. Install new perimeter protection in line with BC Hydro’s Physical Security Application Guide: including crash-rated gates controlled by electronic access control and visible by connected cameras;
ii. Install basic level of perimeter protection: this alternative would focus on lower cost options such as standard gates over crash-rated gates and not introducing video management systems. This alternative would not seek to align with BC Hydro’s Physical Security Application Guide; and
iii. Do nothing: this alternative would decline or defer the investment and not address the physical security issues at the facility and dam at this time.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
• Improve the physical security at GMS Generating Facility.</td></tr>
<tr><td colspan="2">Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="3">Additional Information:
N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td>Investment Planning ID:
G003837</td><td colspan="2">Project Name:
G.M. Shrum – U5 Generator Refurbishment</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Future</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• BCUC IRs 1.116.8 and 2.253.3
F22 RRA:
• Chapter 6, page 6-28
• Appendix I - Generation, line 65
• BCUC IR 1.43.1</td></tr>
<tr><td colspan="3">Description:
The purpose of the project is to return the generator health to good condition at 275 MVA and consider increasing unit capacity to 321 MVA, with no major intervention expected for at least the next 15 to 25 years.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Unit 5 generator at G.M. Shrum Generating Facility is in Poor condition according to the Asset Health Rating methodology. In 2016 the unit experienced a ground fault which started as a single phase to ground fault and evolved into a three-phase fault. Temporary repairs were conducted as an interim risk mitigation plan. Issues driving the Poor rating include:
• Deterioration of the stator winding insulation as measured through standard testing and based on fault history; and
• Deterioration of the stator core with exhibiting core waves, lamination fretting and core deformation.
Intervention is proposed to sustain long-term reliability of the unit.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
BC Hydro is considering three alternatives:
i. Do Nothing: Continue with Preventative Maintenance program;
ii. Rewind Unit 6 Stator: Restore stator windings to “as new” condition to enable reliable operation; and
iii. Replace Unit 6 Stator: Restore stator components through replacement of stator components to enable reliable operation.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
• Improve reliability of the Unit 5 generator</td></tr>
<tr><td colspan="2">Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="3">Additional Information:
N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: G000124	Project Name: G.M. Shrum – U6 Generator Refurbishment	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** F20-F21 RRA: • BCUC IRs 1.116.8 and 2.253.3	
Description: The purpose of the project is to return the generator health to good condition at 321 MVA, with no major intervention expected for at least the next 15 to 25 years.		
Key Drivers: • Reliability		
Issues Being Addressed: The Unit 6 generator at G.M. Shrum Generating Facility is in Poor condition according to the Asset Health Rating methodology. Issues driving the Poor rating include: • Deterioration of the stator winding insulation as measured through standard testing; • Deterioration of the stator core with exhibiting fretting, chevroning and lamination bulging; and Intervention is proposed to sustain long-term reliability of the unit.		
Discussion of Alternatives: BC Hydro is considering three alternatives: i. **Do Nothing:** Continue with Preventative Maintenance program; ii. **Rewind Unit 6 Stator:** Restore stator windings to "as new" condition to enable reliable operation; and iii. **Replace Unit 6 Stator:** Restore stator components through replacement of stator components to enable reliable operation.		
Project Impacts and Benefits: • Improve reliability of the Unit 6 generator		
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.	
Additional Information: N/A		

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: G003336 G000131	Project Name: G.M. Shrum – Intake Operating Gate Hydraulic Upgrade G.M. Shrum – Intake Operating Gate and Intake Mainenance Gate Refurbishment	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** F20-F21 RRA: • Chapter 6, page 6-96 • Appendix I - Generation, line 72 and 73; Appendix J, page 63; Appendix K, Page 13 • BCOAPO IR 1.62.1 PUBLIC Attachment 1 • BCUC IRs 1.116.8; 1.133.1 Confidential; 2.253.3 F22 RRA: • Chapter 6, page 6-28 • Appendix I - Generation, line 60 and 61	

Description:

The purpose of this project is to recoat and refurbish the 10 intake operating gates and two intake maintenance gates and to address reliability risks associated with operating the hydraulic systems used to raise and lower the 10 Intake Operating Gates.

Key Drivers:

- Reliability

Issues Being Addressed:

G.M. Shrum Generating Facility has 10 intake operating gates and two intake maintenance gates. The gates have been in use since the 1970's and the coatings on all 12 gates have an Equipment Health Rating of Poor or Unsatisfactory. Based on available inspection reports, the gates are suitable for refurbishment in the near term. If left untreated for an extended period, the opportunity to recoat and refurbish could be missed, requiring a higher cost investment such as replacement.

The ten Intake Operating Gates are opened and closed by hydraulic systems which consist of hydraulic cylinders, hydraulic power units (**HPUs**) and hydraulic lines. These are all original plant equipment from the 1970's. Issues being addressed include: insufficient emergency close hoist capability, pitting corrosion of the hydraulic lines and lack of fail-safe and redundancy for the HPUs.

Discussion of Alternatives:

BC Hydro is considering three alternatives for the gate refurbishment:

i. **Life Extension:** prioritize work on the 12 gates based on severity and/or availability. Some coating, structural and mechanical deficiencies would be deferred to a later date;

ii. **Refurbishment:** fully refurbish the gates to maximize their life expectancy; and

iii. **Replacement:** replace gates with new gates that have a minimum design life of 75 years.

BC Hydro is considering two alternatives for the gate hydraulic upgrade:

i. **Partial upgrade** of targeted hydraulic components: Upgrade the hydraulic hoisting systems to provide sufficient capacity for emergency closure of the operating gates and refurbish the hydraulic cylinders. This alternative would not address the issue of HPU redundancy; and

[1] Start Date of Construction is the Implementation Approval Date.

ii. **Complete upgrade** of hydraulic components: A complete upgrade of the hydraulic hoisting system on Units 1 to 10 including the hydraulic cylinders, the hydraulic lines and individual HPUs for each unit.	
Project Impacts and Benefits: • Extend life of intake operating gates and intake maintenance gates by restoring the protective coating. • Improved reliability of the intake operating gates.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: As of the currency date of the Capital Plan, IPID G003336 and G000131 were expected to be released as two projects. At the time of initiation, it was determined that these investments should be released and executed under one IPID. This appendix J summary addresses the combined scope of the two investments.	

<table>
<tr><td>Investment Planning ID:
G000128</td><td colspan="2">Project Name:
GMS - Unwatering System Refurbishment</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• BCUC IRs 1.116.8; 2.253.3</td></tr>
<tr><td colspan="3">Description:
The objective of the project is to provide a safe and reliable unwatering system at the G.M. Shrum (GMS) Generating Facility to facilitate unit outages, as well as regular maintenance and inspections of the generating units.</td></tr>
<tr><td colspan="3">Key Drivers:
• Safety
• Environmental
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
Due to the deteriorating condition of the unwatering system at the GMS Generating Facility, there are safety, environmental and reliability risks with the equipment. If the pumps are not working properly and the water cannot be evacuated adequately, the powerhouse could potentially be flooded. In addition, if there is a failure of the components responsible for decontaminating the water, the waterway could become contaminated. There have also been delays to operation due to the draft tube drain valves failing to close when attempting to get a unit back online.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
BC Hydro considered three alternatives:
i. Unwatering System Replacement/Upgrade;
ii. Unwatering System Refurbishment; and
iii. Do Nothing.
Alternative i, unwatering system replacement/upgrade, is the preferred alternative because it is the most cost-effective solution to address the reliability risks by replacing all critical system components of the equipment. Alternative ii was not selected as it would not meet the technical requirements of the project. Alternative iii was not selected as it does not address the risks nor meet the project objectives.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
• Reduced environmental and safety risks by ensuring water can be evacuated adequately to minimize the risk of powerhouse flooding.
• Reduced environmental risk by minimizing potential failure of unwatering system components responsible for decontaminating the water.
• Improves the reliability of the unwatering system by reducing the likelihood of unplanned outages, as well as facilitating outages for maintenance, inspections and planned projects.</td></tr>
<tr><td colspan="2">Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined as the project reaches Implementation Phase.</td></tr>
<tr><td colspan="3">Additional Information:
N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="1">Investment Planning ID:
G000556</td><td colspan="2">Project Name:
Hugh Keenleyside – Spillway and Low-Level Outlets Concrete Upgrade</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• Chapter 6, page 6-89
• Appendix I - Generation, line 19; Appendix J, page 23; Appendix K, page 15
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-25
• Appendix I - Generation, line 20</td></tr>
<tr><td colspan="3">Description:
The objective of this project is to upgrade damaged concrete structures in the Hugh Keenleyside Dam's spillway and low-level outlets, restoring them to near-original condition. This upgrade will extend these structures' service lives and permit a wider range of operational options relating to the passage of water over the spillway and through the dam.
Refer to Appendix K – Hugh Keenleyside Facility Asset Plan for additional information.</td></tr>
<tr><td colspan="3">Key Drivers:
• Financial
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Hugh Keenleyside Dam has been classified as an Extreme consequence dam based on the BC Dam Safety Regulation.
Since the dam was put into operation in 1968, there has been localized loss of concrete to the spillway and low-level outlets due to erosion, abrasion and cavitation to the extent that the concrete reinforcing steel is exposed in a number of locations. Low Level Outlets 1 and 4 have sustained the largest amount of damage.
The rate of progression of concrete damage is unpredictable, and there is the potential need for a portion of the spillway or low-level outlet to be taken out-of-service with little or no advance notice. In this event, immediate repairs implemented under urgent or emergency conditions would be required.
With the benefit of modern numerical hydraulic modelling, BC Hydro implemented operational changes that restrict use of the low-level outlets which are expected to slow (but not stop) the progression of damage. The operational changes, however, have reduced operational flexibility in passing flows.
Maintenance and repairs to the concrete have been carried out over the years, but with limited success. Due to the progression of damage, the required frequency, extent, and cost of repairs (largely underwater) is expected to grow with diminishing effectiveness.</td></tr>
</table>

1 Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives:

BC Hydro considered three alternatives:

i. **Do nothing,** this alternative involves temporarily or permanently foregoing the repair to the damaged concrete structures;

ii. **Upgrade structural concrete in the dry,** with complete isolation of the structures from the downstream tailwater; and

iii. **Upgrade structural concrete under water,** with divers utilizing customized procedures and concrete mixes developed for this specific task.

Alternative iii, upgrade structural concrete under water, was selected as the Single Viable Alternative that will meet the reliability and financial objectives of the Project. Alternative i is not viable as there is a reasonably high risk that a rapid progression of damage could occur which may result in severe financial, environmental, and reputational impacts. Repairs are expected to become increasingly expensive and decreasingly effective over time and the point at which these structures will no longer be fit for safe use cannot be accurately predicted. Alternative ii is not viable due to the significant operational and environmental impacts that would occur due to the large size of the cofferdam needed to isolate the tailwater. Also, building the cofferdam would prevent the use of the Hugh Keenleyside Dam spillways for water conveyance and potentially impact BC Hydro’s obligations under the Columbia River Treaty.

Project Impacts and Benefits:

- Extended life of the spillway and low level outlet structures.
- Reduction of anticipated maintenance costs and outages.
- Elimination of concerns that a sudden progression of damage will force some or all of these discharge facilities to be taken out of service, requiring even more costly interventions under urgent or emergency conditions.
- Increased flexibility of operations to pass flows that preserve the integrity and service life of the structure while mitigating environmental impacts.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

Operations at Hugh Keenleyside Dam have international impacts on flow regulation, power generation and flood control under the terms of the Columbia River Treaty.

Investment Planning ID: G000585	Project Name: John Hart Dam Seismic Upgrade	
Forecast Capital Cost: $738.7 million to $432.3 million	**Forecast In-Service Date:** Fiscal 2030	**Start Date of Construction:**[1] Fiscal 2023
Development Phase: Definition	**Filing Reference:** Amended F12-F14 RRA: • Application: Amended Appendix I, page 13, Amended Appendix J, page 57 • BCUC IRs 1.205.1 Attachment 1, 1.219.10 Attachment 1, 2.127.1 BC Hydro's F2014 Annual Report to BCUC: • Attachment to Section 8 – Part 2 Appendix I, line 98 Appendix J, page 18 F17-F19 RRA: • Appendix I, line 13, Appendix J, page 13, • BCUC IRs 1.70.3,1.73.1, 1.73.9, 1.82.1 – 1.82.9, 1.86.6, 2.249.8, 2.260.4, CEABC IRs 1.17.1 - 1.17.5, 2.39.1 – 2.39.4, 2.40.1, 2.40.2, BCOAPO IRs 1.36.1, 1.36.2, CECBC IRs 1.90.1, 2.156.1 F20-F21 RRA: • Chapter 6, page 6-26 and 6-89 • Appendix I - Generation, line 10; Appendix J, page 13; Appendix K, page 1 • CEABC IR 1.14.3 • BCUC IRs 1.115.2; 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-25 • Appendix I - Generation, line 9 • BCUC IRs 1.53.4; 1.45.2	
Description: The purpose of this project is to address seismic deficiencies of the John Hart Dam so that this facility can be relied upon to withstand the effects of a major earthquake and to operate post-earthquake. The selected alternative will make improvements to the operational reliability of the spillway gates and will reduce the potential for dam overtopping due to flow imbalances between the John Hart and upstream facilities and is consistent with the continued operation of the John Hart Generating Station. Refer to Appendix K – Campbell River Systems Engineering Assessment for additional information.		

1 Start Date of Construction is the Implementation Approval Date.

Key Drivers:

- Safety
- Financial
- Reputational
- Environmental

Issues Being Addressed:

The John Hart Dam is classified as an Extreme consequence dam based on the BC Dam Safety Regulation. As such the expected seismic performance is for no uncontrolled release for the Maximum Design Earthquake (**MDE**) with an annual exceedance frequency of once in 10,000 years. A seismic performance investigation was carried out and it was determined that the withstand of the various component dams and spillway gate system is less than the MDE. Damage from a seismic event could lead to uncontrolled release of water from the reservoir, with significant risk to life, financial loss and reputational damage. Therefore, seismic upgrades to the dam and spillway gates system are required.

In addition to the seismic-related deficiencies, there is a risk of overtopping the John Hart Dam due to unplanned generation flow imbalance between John Hart and the upstream Ladore facility. A free overflow spillway is planned to address this concern.

The scope of this project includes the design and construction of the following:

- Upgrades to the Middle Earthfill dam and Power Intake Dam;
- Upgrades to the North Earthfill dam;
- Upgrades to the concrete dam, including incorporation of a free overflow spillway; and
- Upgrades to the spillway gates system.

Discussion of Alternatives:

BC Hydro considered four alternatives:

i. **Do nothing:** defer, either temporarily or permanently, the correction of the seismic deficiencies of the John Hart Dam. Could include an interim response plan such as: including availability of 24/7 electricians post-earthquake to control operation of the dam or improving instrumentation at the dam such as addition of cameras in an effort to be able to provide a more rapid evaluation of the state of the dam post-earthquake;

ii. **Decommission** the John Hart Dam;

iii. **Permanently lower the reservoir** to reduce loading on the dam; and

iv. **Upgrade the John Hart Dam,** to ensure: a) no uncontrolled release of reservoir following a MDE; and b) the dam suffers only minor damage such that an immediate deep or prolonged drawdown is not required to maintain post-seismic river flow control.

Alternative iv, upgrade the John Hart Dam, was selected as the preferred alternative as it is the only alternative that satisfies the dam safety objectives. Alternative ii is not consistent with the implementation of the John Hart Replacement Project. Alternative iii would not satisfy dam safety requirements as it would not improve the seismic withstand nor materially improve the consequences of dam failure. Further Alternative iii would have unfavourable economic and environmental consequences, as it would reduce generation at the John Hart Generating Station due to the reduced head and would expose currently inundated reservoir areas.

Project Impacts and Benefits:

- Improve safety by addressing seismic deficiencies of the John Hart Dam so that this facility can be relied upon for post-earthquake operation.
- Avoid potential for fatalities, financial loss and reputational impact due to an uncontrolled release of water from the reservoir, in the event of an earthquake up to and including the MDE.

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

As the planning level estimate for this project is over $100 million, BC Hydro expects to submit an application to the BCUC under Section 44.2 for this project.

Planning is currently underway for upgrades at the upstream Strathcona and Ladore facilities (Strathcona Discharge Upgrade Project, G000525; and Ladore Spillway Seismic Upgrade Project, G000668). Planning for these two projects is being considered in conjunction with the John Hart Dam Seismic Upgrade project for the following reasons:

- The projects are planned with similar and potentially overlapping construction schedules;
- The projects are relatively close geographically to one another;
- The projects have some similar scope elements that will require similar contractor expertise; and
- The projects all reside on the Campbell River and the work will need to be considered from a river system management perspective and coordinated accordingly.

Investment Planning ID:	Project Name:	
G003811	Kootenay Canal - Canal Concrete Liner Joints Upgrade	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** New	

Description:

The objective of this project is to significantly reduce water leakage from the Kootenay Canal and reduce the risk of sudden collapse of the Kootenay Canal concrete slab liner and potential breach of the Canal by installing functioning water stops at all slab to slab and all slab to plinth curb joints.

Key Drivers:

- Safety
- Reliability

Issues Being Addressed:

Kootenay Canal starts at the downstream end of Kootenay Lake, paralleling a stretch of the Kootenay River and conveys water some 4.5 km downstream. On the North side of the Canal, concrete faced rockfill has been constructed to form the Canal where the bedrock is lower than the Canal's design elevation. The inner surface of this rockfill was made watertight by placement of concrete liner slabs. There are in excess of 500 slabs along the full length of the Canal. The slabs are separated by an equal number of joints that are nominally one inch wide. The key feature of the joints is a PolyVinyl Chloride (**PVC**) water stop that spans across the joint between adjacent slabs. The vast majority of the Canal's liner slab joints are original and have suffered considerable degradation and increased leakage. If left untreated, the leaks could eventually be sufficient to suddenly wash out the bedding fill that underlies a slab, which could in turn lead to the sudden collapse of Kootenay Canal.

A similar defect that led to a previous leakage event and other potential defects in the canal's forebay segment was previously treated by the widespread application of Carpi membrane in 2014. This project will treat degraded liner slab joints in the upstream portions of the canal.

Discussion of Alternatives:

BC Hydro is considering three alternatives:

i. **Do Nothing:** continue to monitor leakage;

ii. **Apply External Waterstops to Slab joints:** this could be achieved by application of a Carpi membrane or similar technology as was done in 2014; and

iii. **Partial Demolition:** and reconstruction of joints using conventional waterstops.

The "Do Nothing" alternative does not address the continued degradation and leakage of the canal joints. The failure mechanism of a sudden washout of bedding fills under a slab cannot be effectively managed by surveillance in the long term.

The partial demolition and reconstruction of the slab liner joints using conventional waterstops, would have a significantly higher cost and potentially create new joints where leakage could occur.

Applying external waterstops at all degraded or potentially degraded slab joints addresses the issues identified above and is expected to be the preferred alternative, but this will be confirmed when the project is initiated.

1 Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits: • Extended life of the Kootenay Canal structure. • Reduction of anticipated maintenance costs and outages. • Improved worker and public safety by preventing the breach of the Canal and an uncontrolled release of water.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: N/A	

Investment Planning ID:	Project Name:	
G003058	Kootenay Canal - U1 - U4 Generators Refurbishment	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Identification	**Filing Reference:** New	

Description:

The purpose of this project is to address the reliability issues associated with the four generator units at Kootenay Canal (**KCL**) Generating Facility.

Key Drivers:

- Reliability

Issues Being Addressed:

The KCL Generating Facility Unit 1 to 4 generators have been in-service since 1976 and have reached their end of life. The latest Asset Health Rating of Unit 1, 3 and 4 generators is Poor and Unit 2 is Unsatisfactory. Due to the condition of the generators, there is an increased risk of an in-service failure, resulting in a long duration forced outage at KCL Generating Facility, a key generating facility in BC Hydro’s fleet.

Discussion of Alternatives:

BC Hydro is considering four alternatives:

i. **Replace Generator**, which includes replacement of stator, rotor and other major components;

ii. **Partial Replacement**, which includes replacement of stator, rotor pole re-insulation or replacement, refurbishment of other major equipment;

iii. **Refurbishment**, which includes re-wind of the stator, and may include refurbishment of other major components; and

iv. **Defer Major Intervention**.

The project is in Identification phase and in the process of further assessing alternatives. The alternatives will be assessed on a unit by unit basis. The preferred alternative has not yet been determined.

Project Impacts and Benefits:

- Improve the reliability of the Units 1 to 4 generators

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase.	To be determined as the project reaches Implementation Phase.

Additional Information:

N/A

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td>Investment Planning ID:
G000952</td><td colspan="2">Project Name:
Kootenay Canal Modernize Controls</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Definition</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• BCUC IR 1.73.1, BCOAPO IR 1.36.2
F20-F21 RRA:
• Chapter 6, page 6-95
• Appendix I - Generation, line 57; Appendix J, page 54; Appendix K, page 20
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-27
• Appendix I - Generation, line 47</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to improve the long-term reliability, maintainability, operability and safety of the control systems, exciters and select governor mechanical components for all four generating units at Kootenay Canal Generating Station.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Maintainability
• Safety</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Kootenay Canal Generating Station is categorized as a Key facility according to BC Hydro’s Facility Asset Plans. The facility has been operating with high reliability since 1975. However, the unit transformers and turbines are the only major water-to-wire components that have been replaced. The exciters, governors, unit auxiliary control Alternating Current (AC) distribution panels and controls systems are all original and have reached end-of-life.
Risks to be addressed by this project include technical expertise in the marketplace and within BC Hydro is no longer readily available to maintain this equipment; spare parts are increasingly unavailable; mechanical components have worn out; and, decreased control systems reliability. In addition, the AC distribution panels do not meet current arc flash protection standards or Worker Protection Practices for switching and lock-out. Over the past 12 years, Kootenay Canal has experienced 23 forced outages due to the failures of the aged exciters, governors, and unit control relays.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
BC Hydro considered four alternatives:
i. Base scope only – replace controls (unit controls, exciter controls, and governor controls) and replace exciters;
ii. Base scope, plus replace unit AC distribution panels and select governor mechanical components;</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

iii. Base scope, plus replace unit AC distribution panels and full governors; and

iv. Do nothing – continue to maintain and operate as currently done.

Alternative ii is the preferred alternative as it is the lowest cost alternative that addresses the reliability, maintainability, and safety risks associated with the controls, exciters, governors, and unit AC distribution panels.

Alternative i is inferior to Alternative ii because it would cost more in the long-term to address the reliability, maintainability and safety risks associated with the equipment, and would expose BC Hydro to retained risks associated with the governors and AC power distribution panels until these are replaced.

Alternative iii is not cost effective. The remaining industry life expectancy of the governors is more than 50 years, and replacement of this equipment can be deferred until that time.

Alternative iv is not viable because it would not meet the Project objectives. The reliability, maintainability and safety risks of the equipment cannot be mitigated to an acceptable level through maintenance, and these risks will continue to increase over time.

Project Impacts and Benefits:

- Improve the long-term reliability, maintainability, operability and safety of the control systems, exciters, governors and the AC distribution panel.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

N/A

Investment Planning ID: G000459	Project Name: La Joie – Dam Improvements	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Identification	**Filing Reference:** F22 RRA: • Chapter 6, page 6-25 • Appendix I: Generation - line 10 • BCUC IRs 1.43.1; 1.45.2	
Description: The La Joie Dam Improvements Project has been initiated to mitigate Dam Safety risks related to seismic and static deficiencies associated with the dam, intake structure, and flow passage.		
Key Drivers: • Safety • Environmental • Financial Loss • Reputational • Reliability		
Issues Being Addressed: The La Joie embankment dam, which impounds Downton Reservoir, is classified as an Extreme consequence dam based on the BC Dam Safety Regulation. The dam is expected to deform during a seismic event resulting in increased seepage through the dam and potentially escalating to an uncontrolled release of the reservoir following an earthquake with a return period of about 2,200 years. Significant damage to the power intake tower that could lead to failure is expected following an earthquake with a return period of about 1,000 years, and the water passage system cannot be relied upon to operate following an earthquake further limiting BC Hydro's ability to manage the post seismic condition. Uncontrolled release of the reservoir would result in financial damage, reputational damage, environmental impact, and possible fatalities. The identified Dam Safety risks are currently being managed through operational changes where the Downton Reservoir is operated at a reduced level, and other monitoring and maintenance efforts. However operating Downton Reservoir at a reduced level creates operational constraints for the Bridge River System which can necessitate discharges down the Lower Bridge River that exceed water use plan targets and have environmental impacts. The La Joie Dam is the uppermost dam in the Bridge River System and the Downton Reservoir impounded by the dam provides significant storage and inflow buffering capacity for the downstream generating facilities. As such, decisions relating to the La Joie facility must also consider potential impacts on the full Bridge River System.		
Discussion of Alternatives: BC Hydro is considering four alternatives: i. **Do Nothing:** this is to maintain the status quo and should be considered as a deferral as the condition of the shotcrete face is approaching end of its serviceable life. Operating the reservoir at a lower level reduces operational flexibility for the system and increases the likelihood of downstream impacts;		

[1] Start Date of Construction is the Implementation Approval Date.

ii. **Decommissioning of La Joie Dam:** this would naturalize flows at Upper Bridge River and eliminate the operational buffer associated with Downton Reservoir. Loss of the buffer increases the likelihood of downstream impacts but does naturalize terrestrial areas upstream of La Joie; iii. **Improve the Existing Dam to Operate at Normal Reservoir Level:** improve the dam to, generally, operate as originally intended. This provides the maximum operational flexibility on the Bridge River System minimizing downstream impacts. Upstream impacts (i.e., reservoir inundation) remain unchanged from the original; and iv. **Improve the Existing Dam to Operate at a Reduced Operating Level:** the reduced operating level is to be determined and would, presumably, be at a level to balance impacts and benefits. The project is currently in Identification and the alternatives are being evaluated.
Project Impacts and Benefits: • Mitigate or eliminate Dam Safety risks related to seismic and static deficiencies associated with the dam, intake structure, and flow passage.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:
Regardless of which alternative is selected (except for the Do Nothing Alternative), BC Hydro expects to submit an application to the BCUC under Section 44.2 of the *Utilities Commission Act* for the project.

Investment Planning ID: G002326	**Project Name:** La Joie - Governor Pressure Regulating Valve Replacement	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** New	

Description:

The purpose of this project is to address the operating risks with the deteriorating governor, turbine inlet valve (**TIV**) and pressure relief valve (**PRV**) at the La Joie generating station. The project will upgrade these assets to restore long-term reliability and address risks with common points of failure across the systems.

Key Drivers:

- Reliability
- Safety

Issues Being Addressed:

The penstock at La Joie was originally built prior to the powerhouse and was used to pass water from the Downton Reservoir into Carpenter Reservoir via a hollow cone valve (**HCV**). As such, the penstock has relatively thin walls because it wasn't designed for pressure transients associated with relatively fast wicket gate operation on a turbine. When the unit was added in 1956 a pressure relief valve (**PRV**) was required to ensure pressure transients associated with relatively fast wicket gate operations would not damage the penstock.

This project will address reliability issues with the governor and mitigate the risk associated with the current common low-pressure hydraulic power unit (**HPU**). The project will also upgrade the PRV to ensure the PRV can be operated for up to six-months continuously to support water management during the La Joie Dam Improvements project.

The governor is over 60 years old, most of its components are original, and have exceeded their expected service life. The current Asset Health Rating of the governor is Poor. The governor and the PRV are mechanically linked and have a common hydraulic system that is also shared with the TIV. The PRV and its discharge pipe have suffered from severe cavitation and fatigue damage in the past. The PRV underwent major repairs in 2000, 2004, 2013, 2014 and 2016 and several major repairs have also been undertaken on the discharge pipe. Failure of either the governor or PRV would result in a loss of generation and the inability to manage the Downton Reservoir levels which would pose an unacceptable dam seismic risk.

Discussion of Alternatives:

As stated above the governor and the PRV are mechanically interlocked and share a common low pressure HPU and accumulator. The TIV also share the same low pressure HPU and accumulator with both the governor and PRV. Due to the interconnectivity of the equipment there are many technical options and three key alternatives were identified.

Replacing the governor and upgrading the hydraulic system is a common scope item for all alternatives due to the assets poor condition.

BC Hydro is considering three alternatives:

i. **PRV refurbishment, and governor/hydraulic system upgrade**;

ii. **PRV replacement and governor/hydraulic system upgrade**; and

1 Start Date of Construction is the Implementation Approval Date.

iii. **PRV refurbishment and Auxiliary Bypass Valve (ABV) and governor/hydraulic system upgrade**: This involves replacing the ABV (a valve that has not been used since construction of the dam) with a new valve that will function as the PRV and using the old PRV with some modifications as a standby PRV.	
Project Impacts and Benefits: • Improved reliability of governor system, PRV and TIV • Ability for the unit to run remotely • Provide reliable water conveyance during normal operations • Ability for six months of water conveyance to enable the La Joie - Dam Improvements project	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: N/A	

<table>
<tr><td>Investment Planning ID:
G000668</td><td colspan="2">Project Name:
Lador Spillway Seismic Upgrade</td></tr>
<tr><td>Forecast Capital Cost:
$269.4 million to $154.9 million</td><td>Forecast In-Service Date:
Fiscal 2028</td><td>Start Date of Construction:[1]
Fiscal 2024</td></tr>
<tr><td>Development Phase:
Definition</td><td colspan="2">Filing Reference:

Amended F12-F14 RRA:
• Amended Appendix I, line 118; Amended Appendix, page 62

BC Hydro’s F2014 Annual Report to the BCUC:
• Attachment to Section 8 – Part 2
Appendix I, line 118
Appendix J, page 22

F17-F19 RRA:
• Appendix I, line 14, Appendix J, page 15
• BCUC IRs 1.70.3,1.86.1-1.86.4.1, 1.86.5, 1.86.6, 2.249.6, 2.258.1 to 2.258.6, 2.260.4
• BCOAPO IRs 1.36.1, 2.80.1

F20-F21 RRA:
• Chapter 6, page 6-89
• Appendix I - Generation, line 11; Appendix J, page 15; Appendix K, page 1
• BCUC IRs 1.115.2, 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1

F22 RRA:
• Chapter 6, page 6-25
• Appendix I - Generation, line 11
• BCUC IR 1.45.2</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to implement seismic and system reliability upgrades to the structures, gates, mechanical systems, controls and power supplies for the spillway of the Ladore Dam so that this facility can be relied upon for post-earthquake operation as well as for reliable operation under normal and flood conditions.
Refer to Appendix K – Campbell River Systems Engineering Assessment for additional information.</td></tr>
<tr><td colspan="3">Key Drivers:
• Safety
• Financial
• Reputational</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">

Issues Being Addressed:

The Ladore Dam is classified as an Extreme consequence dam based on the BC Dam Safety Regulation. As such the expected seismic performance is for no uncontrolled release for the Maximum Design Earthquake (**MDE**) with an annual exceedance frequency of once in 10,000 years. A seismic performance investigation was carried out, and it was determined that the withstand of the spillway gates and hoist structure is less than the MDE, and damage could lead to an uncontrolled release of water from the reservoir. Failure of the Ladore gates could lead to a flow imbalance at John Hart Dam, located about 1 km downstream, with potential for overtopping of the John Hart Dam, potentially resulting in fatalities, financial loss and reputational damage.

The scope of this project includes upgrades to the Ladore spillway to ensure that:

- In the event of an MDE, the spillway and water conveyance system act as an integral water barrier to retain the Ladore Reservoir;
- The spillway can release water in a controlled manner after a seismic event up to MDE; and
- Electromechanical systems that operate the spillway have an acceptable level of reliability, in both post-earthquake and normal service, including during high inflows and floods.

</td></tr>
<tr><td colspan="2">

Discussion of Alternatives:

BC Hydro considered three alternatives:

i. **Refurbishment** of gates, towers and hoists;

ii. **Replacement** of gates **and refurbishment** of towers and hoists; and

iii. **Replacement** of gates, towers and hoists.

Alternative iii, replacement of gates, was selected as the preferred alternative because it provides the best long term solution as compared to Alternatives i and ii, due to a more reliable and robust design, increased ease of maintenance and safety for BC Hydro operation staff, and reduced environmental impacts during and after construction.

</td></tr>
<tr><td colspan="2">

Project Impacts and Benefits:

- Improve safety by addressing seismic deficiencies of the Ladore Dam spillway, so that this facility can be relied upon to safely retain the reservoir through an earthquake to and including the MDE and for post-earthquake operation.
- Improve safety by improving the operational reliability of the Ladore Dam spillway gates to control the discharge of reservoir inflows over the spillway.

</td></tr>
<tr><td>

Project Implementation Phase Risk:

Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.

</td><td>

Risk Treatment:

To be determined when the project reaches Implementation.

</td></tr>
<tr><td colspan="2">

Additional Information:

As the planning level estimate for this project is over $100 million, BC Hydro expects to submit an application to the BCUC under section 44.2 for this project.

Planning is currently underway for upgrades at the upstream Strathcona facility and downstream John Hart facility (Strathcona Discharge Upgrade Project, G000525; and John Hart Dam Seismic Upgrade Project, G000585). Planning for these two projects is being considered in conjunction with the Ladore Spillway Seismic Upgrade project for the following reasons:

- The projects are planned with similar and potentially overlapping construction schedules;
- They are relatively close geographically to one another;
- They have some similar scope elements that will require similar contractor expertise; and
- They all reside on the Campbell River and the work will need to be considered from a river system management perspective and coordinated accordingly.

</td></tr>
</table>

Investment Planning ID: G000168	Project Name: Lake Buntzen 1 – Generator Replacement	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Identification	**Filing Reference:** F20-F21 RRA: • Chapter 6, page 6-96 • Appendix I - Generation, line 78; Appendix J, page 65; Appendix K, page 24 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-27 • Appendix I - Generation, line 48	

Description:

The purpose of this project is to improve the reliability of the generator at the Lake Buntzen 1 (**LB1**) Generating Facility.

Refer to Appendix K – Coquitlam-Buntzen System Facility Asset Plan for additional information.

Key Drivers:

- Reliability

Issues Being Addressed:

The LB1, generator one (60 MW) was assessed in 2016 and the Asset Health Rating is Poor. The main issues leading to this health rating include the poor condition of the stator windings, stator core, and rotor windings, as confirmed by poor electrical test results, visible signs of deterioration and deformation, and a stator winding insulation failure which resulted in two coils cut-out in 2005.

Discussion of Alternatives:

BC Hydro considered four alternatives:

i. **Do Nothing**;
ii. **Rewind generator** (stator and rotor only);
iii. **Refurbish some components of the generator system**; and
iv. **Replace most of the components of the generator system**.

Alternative iv, “Replace most of the components of the generator system”, was selected as the single viable alternative. Alternative i was not considered viable given the deteriorated condition of the generator that will eventually lead to its failure. Alternative ii and Alternative iii were not considered viable as they would only improve asset condition in the short-term, but would not achieve the project objective of extending the asset life by at least 40 years and therefore would likely result in additional future projects to achieve the project benefits.

Project Impacts and Benefits:

- Extend the generator life by at least 40 years.

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase.	To be determined when the project reaches Implementation.
Additional Information: N/A	

<table>
<tr><td>Investment Planning ID:
G000640</td><td colspan="2">Project Name:
Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment</td></tr>
<tr><td>Forecast Capital Cost:
$43.3 million</td><td>Forecast In-Service Date:
Fiscal 2023</td><td>Start Date of Construction:[1]
Fiscal 2021</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
F11 RRA:
• Application: Appendix I, page 3; Appendix J, Page 51
Amended F12 – F14 RRA:
• Application: Appendix I, line 101; Appendix J, page 42
F17-F19 RRA:
• Appendix I, line 39, Appendix J, page 26,
• BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IRs 1.36.1, 1.64.4
F20-F21 RRA:
• Chapter 6, page 6-96
• Appendix I - Generation, line 39; Appendix J, Page 41; Appendix K, Page 24
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-27
• Appendix I - Generation, line 27</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to address water conveyance reliability risks associated with the tunnel from Coquitlam Reservoir to Lake Buntzen Reservoir.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Safety</td></tr>
<tr><td colspan="3">Issues Being Addressed:
There are two Intake Operating Gates located in the tunnel to control flow. In addition, one Intake Maintenance Gate is provided for Single Device Isolation of the two Intake Operating Gates and the tunnel. Tunnel isolation is required to complete inspections and maintenance of the tunnel and Intake Operating Gates.
The Intake Operating Gates are original equipment (1908 and 1911) and are in poor condition. The operating gates have experienced failures due to broken rollers and wire ropes, and have experienced difficulties opening under high head conditions. Failures of these gates impact BC Hydro’s ability to
• Convey water between the Coquitlam Reservoir and Lake Buntzen;
• Generate at Lower Buntzen 1 Generating Station;
• Manage levels in the Coquitlam Reservoir, potentially affecting the public drinking water supply;
• Regulate and manage flows into Lake Buntzen, with potential for overtopping of the spillway at Buntzen Dam and consequent damage to the Lower Buntzen 1 Generating Station; and</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

- Regulate and manage flows into the Coquitlam River which, during extended periods of high inflows, could contribute to incremental flooding along the Coquitlam River.

Discussion of Alternatives:

BC Hydro considered five alternatives:

i. **Do nothing:** continue to repair the gates as they fail;

ii. **Replace Gates:** Replace two Intake Operating Gates at the existing location and install the Intake Maintenance Gate at a new location;

iii. **Replace Gates in New Location:** Enlarge the Intake Operating Gates vertical access shaft, replace the concrete pier to provide a new location for two new Intake Operating Gates, and replace the Intake Maintenance Gate with two new gates at the existing location of the two Intake Operating Gates;

iv. **Replace Operating Gates and Maintenance Gate:** Replace the two Intake Operating Gates and the Intake Maintenance Gate at their existing locations and refurbish the existing Intake Maintenance Gate concrete gate wall; and

v. **Refurbish:** Refurbish the mechanical parts of the two Intake Operating Gates at their existing locations to achieve a 15-year service life, including re-use of gate system components. Replace the Intake Maintenance Gate at its existing location and refurbish the concrete wall for this gate.

Alternative ii, replace gates, was selected as the preferred alternative. The Intake Maintenance Gate is being replaced in a new location to eliminate underwater construction hazards and the Intake Operating Gates will be replaced in the original location. All gates will receive seismic upgrades and remote control with a new local power supply. Alternative i is not considered viable given the deteriorated condition of the gates that will eventually lead to their failure. Alternatives iii was not selected as it was less cost-effective in achieving a long-term solution as compared with Alternative ii. Alternative iv was not selected because it was a higher cost compared with Alternative ii, had a greater potential for cost overruns, had a higher quality risk and had the highest underwater construction safety hazard for divers. Alternative v was not selected because it did not meet the user requirements for a 50-year service life or for seismic withstand, post event tunnel gate operability.

Project Impacts and Benefits:

- Improve reliability of the Coquitlam-Buntzen Tunnel gates.
- Reduce public and worker safety hazards.
- Provide seismic withstand capability for the tunnel gates
- Provide remote control for the gates from Fraser Valley Office.

Project Implementation Phase Risk:	Risk Treatment:
Risk of delays due to unfavourable weather conditions.	The schedule has been designed to complete the work in three two-month outages over a one-year period to align with summer low inflow periods, and reservoir drawdowns will be undertaken in the winter months.

Additional Information:

There is no Asset Health rating for gates, as there are for generating equipment; however, their condition is poor as described.

Investment Planning ID: G003234	Project Name: Lake Buntzen 1 - Penstock Interior Restoration	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** New	

Description:

The purpose of this project is to ensure safe and reliable operation of the Lake Buntzen 1 steel penstock for another 25 years at the lowest lifecycle costs by mitigating the risks due to active corrosion.

Key Drivers:

- Reliability
- Safety
- Financial

Issues Being Addressed:

The Lake Buntzen 1 steel penstock has been in service since 1952 and has an Equipment Health Rating of Unsatisfactory. The penstock interior is exhibiting signs of coating failure and surface corrosion, particularly in the sloped section leading to the downstream Turbine Inlet Valve where general corrosion is occurring over 50 per cent of the surface area.

The penstock's protective coating is intended to prevent corrosion of the steel which can result in reduced material thickness and strength. Without recoating, the extent of corrosion damage will increase and over time will impact the structural integrity of the steel to the point where recoating is no longer viable, and a significantly more costly penstock replacement would be required. Left unaddressed, corrosion damage could result in the penstock being removed from service if no longer safe to operate.

Discussion of Alternatives:

BC Hydro is considering three alternatives:

i. **Do Nothing** and monitor the condition;

ii. **Install Cathodic Protection** to arrest ongoing corrosion; and

iii. **Restore Coating (Interior)** to protect from further corrosion.

The Alternative i, to do nothing, does not address the issues identified above and continued corrosion would impact the structural integrity of the steel to the point where recoating is no longer viable and replacement costs are expected to be significantly higher than recoating the existing penstock. The corrosion rate is unknown and difficult to estimate given the available information.

Alternative ii, installing a cathodic protection system is also not recommended because it is not typically used as corrosion protection of penstock interiors. It could increase maintenance costs and is not likely to be effective due to the service environment and large areas involved.

Based on existing inspection reports, Engineering assessments and a review of other ongoing penstock recoating projects, Alternative iii, to restore the interior coating, addresses the issues identified above and is expected to be the preferred alternative, but this will be confirmed when the project is initiated.

Project Impacts and Benefits:

- Extend penstock life by restoring the interior coating to protect from corrosion.
- Improve equipment reliability and safety by addressing the deteriorating condition of the penstock.

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.
Additional Information: Besides the value provided by generation, the ability to move water through the Lake Buntzen 1 penstock is important for flood risk management and mitigating impacts due to spilling from Lake Buntzen Dam.	

Investment Planning ID: G003211	Project Name: Mica - Reactor 5RX3 Replacement	
Forecast Capital Cost: $42.8 million	**Forecast In-Service Date:** Fiscal 2024	**Start Date of Construction:**[1] Fiscal 2020
Development Phase: Implementation	**Filing Reference:** F20-F21 RRA: • BCOAPO IR 3.174.2 F22 RRA: • Chapter 6, page 6-28 • Appendix I - Generation, line 69 • BCUC IR 1.54.1	

Description:

The purpose of this project is to replace the two 500 kV transmission line reactor banks at the Mica Generating Facility.

Key Drivers:

- Operational Requirements
- Reliability
- Financial Loss

Issues Being Addressed:

There are two reactor banks at Mica (5RX3 and 5RX4), each comprised of three single phase reactors and a neutral. These reactor banks are used for system stability to absorb reactive power and lower line voltages when the transmission lines are lightly loaded. Without these reactors in service, the system operates without its intended redundancy, increasing reliability risks, operational constraints and limiting export opportunities.

On March 31, 2019 the 5RX3 reactor bank at Mica was damaged during an electrical event. Operating restrictions were placed on Mica until the reactor bank is returned to service. Replacement of these reactors was released as an emergency project in April 2019. In response to a separate equipment failure event on the 5RX4 reactor bank at Mica in January 2020, the replacement of the second reactor bank was advanced with a forecast in-service date of 2022. Efficiencies result from completing the work under a single project.

Discussion of Alternatives:

BC Hydro considered four alternatives:

i. **Do Nothing:** Two reactor banks at Mica to remain out of service;

ii. **Replace with Existing Spares:** Existing system spares require modifications that would take a year or more to complete;

iii. **Repair:** Severe damage on two of the single phase 5RX3 reactors included rupture of the main tank. Re-welding and repair is not viable; and

iv. **Replace with New:** Purchase of six single phase reactors, plus a spare.

Alternative iv, replace with new, was selected as the selected alternative. Alternative i is not viable because system operation would remain impaired. Alternative iii is not feasible due to severe damage on two of the single phase 5RX3 reactors including rupture of the main tank and oil loss, such that re-welding and repair of these units is not viable. Alternative ii is not feasible as it would prolong operating constraints by at least one year, and further would result in the need to re-use the remaining Mica single

[1] Start Date of Construction is the Implementation Approval Date.

phase reactors, which would leave Mica with a mix of single-phase reactors that could potentially cause overheating. Furthermore, existing reactors and spares at Mica are vintage 1979 equipment and prior to failure were rated in “Poor” condition. Thus, repair and use of system spares is not a viable option.	
Project Impacts and Benefits: • Restore Mica to normal system operation. • Reduce reliability risks. • Improve export capabilities.	
Project Implementation Phase Risk: Due to equipment damage on one of three single phase reactors, that occurred during shipment of the 5RX4 reactors to Mica, there is a risk of schedule delay to the project in-service date.	**Risk Treatment:** This risk can be mitigated by using the spare reactor at Mica, if the damaged equipment cannot be repaired to meet the project timeline.
Additional Information: N/A	

<table>
<tr><td>Investment Planning ID:
G000181</td><td colspan="2">Project Name:
Mica – U1 – U4 Circuit Breaker and Iso Phase Bus Replacement</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• Appendix H, page 14
F22 RRA:
• Chapter 6, page 6-28
• Appendix I: Generation, line 71
• BCUC IR 1.43.1</td></tr>
<tr><td colspan="3">Description:
The purpose of the project is to improve the reliability of the Units 1 to 4 circuit breakers and Iso-Phase Bus (IPB)at the Mica Generating Station.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The generator circuit breakers used on Units 1 to 4 at Mica have been made obsolete by the original equipment manufacturer as of the end of 2019. This type of air blast breaker requires refurbishment on a recurring cycle, which is no longer possible because the original equipment manufacturer will no longer manufacture the components required or provide the technical support to complete the refurbishment. Replacement of the IPB is also being examined due to the age of the equipment, integration with replacement of the circuit breakers, and increased capacity.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
BC Hydro is considering two alternatives:
i. Replace Circuit Breakers: Long-term reliable operation requires that the circuit breakers be replaced due to equipment obsolescence; and
ii. Replace Circuit Breakers and IPB: In addition to replacing the circuit breakers, this alternative includes replacement of the IPB. The IPB scope will be examined to determine if the benefits of replacement justify the additional investment. The examination will focus on condition and long-term reliability of the IPB, integration benefits of replacement during the circuit breaker replacement and increased capacity benefits.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
• Reliable operation of the unit circuit breakers and IPB at the Mica facility.</td></tr>
<tr><td>Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td colspan="2">Risk Treatment:
To be determined when the project reaches the Implementation Phase.</td></tr>
<tr><td colspan="3">Additional Information:
N/A</td></tr>
</table>

1 Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="1">Investment Planning ID:
G003365</td><td colspan="2">Project Name:
Mica – Discharge Facilities Seismic and Reliability Upgrades</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• Chapter 6, page 6-89
• Appendix H, page 14
• Appendix I - Generation, line 20; Appendix J, page 25; Appendix K, page 26
• BCUC IRs 1.115.2, 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-25
• Appendix I - Generation, line 12
• BCUC IR 1.45.2</td></tr>
<tr><td colspan="3">Description:
Mica Dam discharge facilities include both a three-gated spillway and a two-gated outlet works. The objective of this project is to upgrade these discharge facilities to provide for continued safe containment of the reservoir during an earthquake, safe discharge of water from the reservoir after such an earthquake, and sufficiently reliable operation for all other service conditions, including during periods of high inflows up to extreme floods.
Refer to Appendix K – Mica Facility Asset Plan for additional information.</td></tr>
<tr><td colspan="3">Key Drivers:
• Safety
• Reliability
• Financial
• Reputational</td></tr>
<tr><td colspan="3">Issues Being Addressed:
• The Mica Dam is classified as an Extreme Consequence Category Dam based on the BC Dam Safety Regulations. As such, the expected seismic performance is for no uncontrolled release of the reservoir for the Maximum Design Earthquake (MDE) with an annual exceedance frequency of once in 10,000 years. The MDE has been updated since the dam’s original design and construction and demands from the current design earthquake exceeds the original design capacities. Seismic deficiencies have been identified in various spillway and outlet works structures. Moreover, the gates’ mechanical, electrical, control and power supply equipment have not been seismically qualified and cannot be relied upon to operate after an earthquake. Inability to safely operate the discharge facilities after an earthquake:
- Would preclude a drawdown of the reservoir for dam inspections, repairs, or other emergency measures; and
- Could lead to eventual overtopping of the earthfill dam, resulting in erosion and possible dam failure with significant risk to life, financial loss, environmental consequences and reputational impact.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

- The discharge gates at Mica Dam do not have sufficient reliability to ensure operability when needed during periods of high inflows and reservoir levels, such as during freshet and floods. Failure of the discharge facilities to operate during high inflow events could lead to eventual overtopping of the earthfill dam, resulting in erosion and possible dam failure. Operational reliability improvements to the gate systems in accordance with current BC Hydro principles—including mechanical, electrical, control and power supply sub-systems—are required in order that they can be relied upon to operate when needed.

Discussion of Alternatives:

The Single Viable Alternative is to upgrade the deficient components to meet the current seismic and operational reliability requirements. Given the safety and reliability issues identified and the extreme consequences of Mica Dam failure, do-nothing or long-term retention of the status quo is not acceptable. The project is in Identification phase and in the process of further developing specific scope items.

Project Impacts and Benefits:

- Assured reservoir containment up to and including extreme earthquakes and provision of safe and reliable post-earthquake discharge and drawdown capability to allow for dam inspection, repairs, and other emergency measures, as required.
- Increased operational reliability to reasonably assure discharge function and prevent dam overtopping during high inflows up to and including extreme flood events.
- Reduced potential for fatalities, financial loss and reputational impact due to an uncontrolled release of water from the reservoir.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

Mica Dam provides flow regulation, power generation and flood control under the terms of the Columbia River Treaty.

<table>
<tr><td>Investment Planning ID:
G000172</td><td colspan="2">Project Name:
Mica Modernize Controls</td></tr>
<tr><td>Forecast Capital Cost:
$56.3 million</td><td>Forecast In-Service Date:
Fiscal 2024</td><td>Start Date of Construction:[1]
Fiscal 2019</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
F17-F19 RRA
• Appendix I, line 52, Appendix J, page 31
• BCUC IRs 1.70.3, 1.91.1 – 1.91.4, 2.249.8, 2.260.4 BCOAPO IR 1.36.1.
F20-F21 RRA:
• Chapter 6, page 6-95
• Appendix I - Generation, line 40; Appendix J, page 43; Appendix K, page 26
• BCUC IRs 1.120.1, 1.133.1 Confidential, 2.252.2
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-27
• Appendix I - Generation, line 26</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to modernize the original Mica Unit 1 to 4 analog unit and control room controls, alarms and metering; replace the excitation systems; upgrade the governor controls; and replace the unit protection equipment.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Mica Generating Station is categorized as a Key Facility according to BC Hydro’s Facility Asset Plans. The Mica Unit 1 to 4 control room equipment; unit protection and control equipment; exciter, and governor controls are all approaching end of life. The control room equipment and exciters are no longer supported by suppliers making it increasingly difficult to maintain and obtain spare parts.
The original electromechanical unit protection systems are in Poor condition and there is an increased risk that the protection relays may fail to operate during an electrical fault.
A major failure of either the governor or exciter could result in a generator forced outage of the affected unit for up to 12 months.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">Discussion of Alternatives:
BC Hydro considered three alternatives:
i. Do Nothing and Defer: maintain and replace Units 1 to 4 controls as they fail;
ii. Refurbish: refurbish and life extend Units 1 to 4 controls on selected sub-systems; and
iii. Replacement: replace Units 1 to 4 controls including exciters, governor controls, unit controls, control room controls, remote controls and power distribution switchboards.
Alternative iii, replacement, was selected as the preferred alternative because it is the only technically feasible alternative that fully meets the project objectives of reliability, maintainability and operability. Alternative i was rejected because the unit controls are nearing end of life and there is a heightened reliability and forced outage risk and a risk of reduced operational flexibility at a Key Facility. Alternative ii is not a viable solution as the refurbishment would be ineffective. For both Alternative i and ii equipment reliability, maintainability, spare parts and technical support risks related to continued operation of 40-year old equipment would not be addressed.</td></tr>
<tr><td colspan="2">Project Impacts and Benefits:
• Improve Protection & Control Reliability
• Improve Exciter Reliability</td></tr>
<tr><td>Project Implementation Phase Risk:
Due to the inability to verify all as-built conditions and design assumptions, there is a risk that as found conditions during construction differ from design and budget assumptions. This could lead to unplanned work and potential schedule and cost impacts.</td><td>Risk Treatment:
This risk materialized and the estimated increased cost to the project was approved by the Capital Project Committee of the Board in December 2020.</td></tr>
<tr><td colspan="2">Additional Information:
N/A</td></tr>
</table>

Investment Planning ID: G003207	Project Name: Mica Replace Units 1 to 4 Generator Transformers	
Forecast Capital Cost: $79.8 million	**Forecast In-Service Date:** Fiscal 2023	**Start Date of Construction:**[1] Fiscal 2018
Development Phase: Implementation	**Filing Reference:** F17-F19 RRA: • Appendix I, line 67, Appendix J, page 34 • BCUC IRs 1.70.3, 1.92.1-1.92.3, 2.249.8, 2.260.4 • BCOAPO IR 1.36.1 F20-F21 RRA: • Chapter 6, page 6-95 • Appendix H, page 14 • Appendix I - Generation, line 30; Appendix J, page 34; Appendix K, page 26 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-27 • Appendix I - Generation, line 27	

Description:

The purpose of this project is to replace 12 single-phase generating unit transformers at the Mica Generating facility with explosion-resistant transformers for safe and reliable operation.

Key Drivers:

- Safety
- Reliability

Issues Being Addressed:

The Mica Generating Station is categorized as a Key facility according to BC Hydro's Facility Asset Plans. Twelve single-phase transformers connect the Unit 1 to 4 Mica generators to the transmission network by stepping up the generator output voltage of 16 kV to transmission voltage of 500 kV. The reliability and safety risks associated with these transformers are increasing as the assets age and degrade.

The Asset Health Rating of 10 of the transformers is Poor. After nearly 40 years of service, several of the transformers are showing signs of overheating while others have indications of insulation degradation. The Mica transformers are located in an underground powerhouse, and a failure presents a safety risk for people working in the underground powerhouse in addition to the reliability risks associated a forced outage.

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives: BC Hydro considered three alternatives: i. **Do nothing:** replace transformers at failure; ii. **Refurbishment** and partial replacement; and iii. **Replace** with new single-phase explosion-resistant transformers. Alternative iii, replace, was selected as the preferred alternative because it is the only technically feasible alternative that meets the project objectives. Alternative ii would not allow for installation of explosion-resistant transformer design which were selected for Mica Units 5 and 6 Project based on eliminating the risks associated with working near live oil filled transformers in the underground facility at Mica. Alternative ii would not allow BC Hydro to take advantage of the Master Supply Agreement which specifies the explosion-resistant transformers.	
Project Impacts and Benefits: • Improve transformer reliability. • Reduce safety risk.	
Project Implementation Phase Risk: Due to the age of the old transformers, and the work taking place underground while some other units are operating and energized, there is a risk of serious worker injury or fatality in the event of a transformer explosion in the underground chamber. Due to the inability to verify all as-built conditions and design assumptions, there is a risk that as found conditions during construction differ from design and budget assumptions. This could lead to unplanned work and potential schedule and cost impacts.	**Risk Treatment:** To mitigate this risk, the project has developed a Safety Plan (conforming with BC Hydro's Contractor Safety Program) and utilized the procedures, knowledge and experience gained from other projects performed in the transformer chamber. The project has also implemented safety outages of the adjacent transformers which are not explosion resistant, while work is underway in the chamber. This risk materialized and the estimated increased cost to the project was approved by the Capital Project Committee of the Board in June 2020.
Additional Information: N/A	

Investment Planning ID: G000183	**Project Name:** Mica - U1 - U2 Turbine Overhaul	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** F20-F21 RRA: • BCUC IR 1.115.2 F22 RRA: • Chapter 6, page 6-28 • Appendix I - Generation, line 70 • BCUC IR 1.45.2	

Description:

The purpose of the project is to improve the reliability of the Unit 1 and 2 turbines at the Mica Generating Station.

Key Drivers:

- Reliability
- Financial

Issues Being Addressed:

The Unit 1 and 2 turbines are in Poor condition. These units have been in service for over 40 years without any major turbine overhaul or intervention. The main issues leading to a Poor Asset Health Rating include:

- Ongoing cavitation damage to the runner blades and wicket gates
- Evidence of rubbing between the runner crown and the seal ring in the headcover
- Poor condition of wicket gate bushing

It is expected that turbine efficiency has been reduced because of changes in runner blade profile as a result of cavitation repair. The cavitation damage to the runner blades and wicket gates is managed with interventions and monitoring. The runner clearance and wicket gate bushing condition are managed with inspections and monitoring.

Discussion of Alternatives:

BC Hydro is considering three alternatives:

i. **Do Nothing**: Continue with Preventative Maintenance program to inspect turbines and make repairs where possible without disassembling the unit;

ii. **Overhaul turbines and associated components**: Restore turbine components to “as new” condition to enable reliable operation for 25 years; and

iii. **Replace runners and overhaul turbine and associated components**: Includes Alternative ii. scope as well as replacement of the turbine runners.

Project Impacts and Benefits:

- Improve the reliability of the turbines of Units 1 and 2.

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.
Additional Information: N/A	

Investment Planning ID: G003456	Project Name: Mica Upgrade 600 V Circuit Breakers	
Forecast Capital Cost: $25.7 million	**Forecast In-Service Date:** Fiscal 2022	**Start Date of Construction:**[1] Fiscal 2019
Development Phase: Implementation	**Filing Reference:** F17-F19 RRA: • Appendix I, Hydroelectric - line 40 F20-F21 RRA: • Chapter 6, page 6-95 • Appendix G, page 25 • Appendix I, Generation - line 41, Appendix K, page 26 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 • CEC IR 3.104.2 F22 RRA: • Appendix I, Generation - line 28 • BCUC IR 1.43.1	

Description:

The purpose of this project is to address safety risks with essential loads and the physical location of the diesel generators as well as reliability risk with the 600 V circuit breakers at the Mica Generating Station.

Key Drivers:

- Safety
- Reliability

Issues Being Addressed:

The Mica generating station is categorized as a Key facility according to BC Hydro's Facility Asset Plans. It is over 45 years old. The primary issues being addressed by this project are:

- The station service breakers and switchgear are original equipment, in poor condition resulting in increased frequency of failures and they introduce safety risks with high arc flash categories.
- Station loads placed on essential power are not adequate to maintain safe operation in the event of a fire in the powerhouse. For example, additional intake and exhaust fans are required to operate on essential power to ensure smoke from a fire can be cleared from the powerhouse.
- Location of the diesel generators (i.e. the back-up power for the essential bus) poses a risk of blocking the powerhouse egress route.

Discussion of Alternatives:

BC Hydro considered the following alternatives:

Circuit Breaker and Switchgear Alternatives

i. **Do Nothing:** Operate to failure, accept safety risks;

ii. **Replace Switchgear & Install New Metal Enclosures**: extends life of asset by 25 years but significant arc flash risk remains; and

iii. **Replace Switchgear & Install Arc Resistant Enclosures**: extends life of asset by 25 years and

[1] Start Date of Construction is the Implementation Approval Date.

reduces arc flash risk.

Alternative iii was selected as the preferred alternative for Circuit Breaker and Switchgear Alternatives as it addresses the safety and reliability risks of the equipment. Alternative ii was not selected as a significant arc flash risk will remain. Alternative i was not selected because it does not address the safety risks nor meet the project objectives.

Essential Bus Upgrade Alternatives

i. **Do Nothing**: maintain existing essential load configuration, accept risks of blocking egress route;

ii. Relocate existing 400 kW diesel generators and install additional 600 kW diesel generator: Addresses safety risks but introduces reliability risks; and

iii. **Install two new diesel generators in a new location:** addresses safety risks with no new reliability risks.

Alternative iii was selected as the preferred alternative for the Essential Bus Upgrade Alternatives as the most cost-effective alternative to satisfy the safety and reliability objectives of the project. Alternative ii was not selected because introduces cost and reliability risks with integration of the old diesel generator with the modern control systems. Alternative i was not selected because it does not address the safety risks nor meet the project objectives.

Project Impacts and Benefits:

- Improved reliability of the 600 V circuit breakers and switchgear
- Reduced safety risks of the 600 V circuit breakers and switchgear
- Reduced safety risks of a blocked egress route when back-up power is being provided by the diesel generators

Project Implementation Phase Risk:	**Risk Treatment:**
Due to the configuration of energized bus around the cable connections, removing the cables while the bus is energized, as was originally planned, is not recommended. This may result in the outage requirements to complete load transfers increasing from four days to 12 days and require multiple units out of service during portions of the 12 days. This may require rescheduling of the planned work to accommodate overall system impacts and may result in missing the March 27, 2022 in service date milestone.	The project team will verify the outage requirements and any system constraints to consider regarding the duration and timing of the outages. To minimize schedule impact, some outage work may be moved to evening shifts and project contingency will be used to cover any additional costs.

Additional Information:

N/A

<table>
<tr><td>Investment Planning ID:
G000801</td><td colspan="2">Project Name:
Mica Upgrade HVAC System</td></tr>
<tr><td>Forecast Capital Cost:
$39.9 million</td><td>Forecast In-Service Date:
Fiscal 2023</td><td>Start Date of Construction:[1]
Fiscal 2020</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I, Hydroelectric - line 56
F20-F21 RRA:
• Appendix I, Generation - line 42
• Appendix K, page 26
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-27
• Appendix I, Generation - line 38
• BCUC IR 1.43.1</td></tr>
<tr><td colspan="3">Description:
The purpose of the project is to address the degrading condition of the Heating, Ventilation and Air Conditioning (HVAC) system at the Mica Generating Facility.</td></tr>
<tr><td colspan="3">Key Drivers:
• Safety
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
At the Mica Generating Facility, the existing HVAC system is at end-of-life, with frequent component failures, and is no longer operating as designed. In addition, the performance of the existing smoke management system is being impacted by obsolete HVAC equipment and has compromised the system’s ability to sufficiently pressurize the building under potential fire scenarios.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
BC Hydro considered three alternatives:
i. Do nothing and defer;
ii. Like-for-like HVAC system replacement; and
iii. Like-for-like HVAC system replacement with office area performance upgrades.
Alternative ii was selected as the preferred alternative as it will meet the project objectives of improving safety and reliability with the lowest life cycle cost as compared to Alternatives i and iii.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
• Improve worker safety by safely exhausting smoke and fire gases in egress paths.
• Improve performance and reliability of the HVAC system.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk:	Risk Treatment:
Due to the age of the existing HVAC system and anticipated construction activities, there is a risk of encountering hazardous materials which may result in environmental contamination and worker injury.	The risk is being mitigated by establishing hazardous material removal plans and conducting a hazardous materials survey on HVAC components to quantify risks prior to construction.
Additional Information: There is no Asset Health rating for HVAC equipment.	

<table>
<tr><td colspan="1">Investment Planning ID:
G000241</td><td colspan="2">Project Name:
Puntledge Recoat Interior and Exterior of Steel Penstocks</td></tr>
<tr><td>Forecast Capital Cost:
$35.6 million</td><td>Forecast In-Service Date:
Fiscal 2022</td><td>Start Date of Construction:[1]
Fiscal 2019</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
BC Hydro’s F2014 Annual Report to the BCUC:
• Attachment to Section 8 – Part 2 Appendix I, Appendix J, page 26
F19-F19 RRA:
• Appendix I, line 59, Appendix J page 33,
• BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1
F20-F21 RRA:
• Chapter 6, page 6-95
• Appendix I, Generation - line 44; Appendix J, page 44; Appendix K, page 31 and 33
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-27
• Appendix I, Generation - line 29</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to address safety and reliability risks associated with the Puntledge Generating Station penstock, and achieve an asset life extension through a strip and recoat intervention.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Safety
• Financial
• Environmental</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Puntledge Generating Station is classified as a Strategic facility according to BC Hydro’s Facility Asset Plans. It is located downstream of the Comox Dam and the Puntledge Diversion Dam which are rated Extreme and Very High consequence dams, respectively, based on the BC Dam Safety Regulation.
The penstock at the Puntledge Generating Station has been in-service since 1954. The long steel penstock sections are exhibiting signs of coating failure. The Asset Health Rating for the long steel sections of the penstock is Unsatisfactory.
Without recoating, the extent of corrosion damage will increase and, over time will impact the structural integrity of the steel material to the point where recoating is no longer an option and a penstock replacement is required. Continued corrosion may require the penstock to be removed from service when it is no longer safe to operate. Failure of the penstock could lead to uncontrolled release of water with significant risk to life, financial loss, and reputational damage.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives:

BC Hydro considered four alternatives:

i. **Do Nothing and Monitor**;

ii. **Strip and Recoat Only Exterior Surface of Steel Penstocks**;

iii. **Strip and Recoat Exterior and Interior Surfaces of Steel Penstocks**; and

iv. **Complete Replacement of Penstocks**.

Alternative iii, strip and recoat exterior and interior surfaces of steel penstocks, was selected as the preferred alternative as it addresses safety and reliability objectives, and extends the penstock life. Alternative i or Alternative ii would not deliver a significant overall penstock life extension because corrosion of the uncoated and unprotected steel penstock sections would not be achieved. Loss of steel would persist, potentially undermining the structural integrity of the penstock, which are considered high pressure vessels conveying significant volumes of water and are key water passage components used for generation. Penstock failures may cause extensive economic and infrastructure damage. Alternative iv was not selected as it would be too costly compared to Alternative iii which also addresses the project objectives.

Project Impacts and Benefits:

- Improve equipment reliability and safety.
- Extend penstock life.
- Reduce potential for fatalities, financial loss, and reputational damage due to an uncontrolled release of water from the reservoir.

Project Implementation Phase Risk:	**Risk Treatment:**
There is a risk that the conditions encountered during construction are worse than was assumed at the time the project budget was approved	This risk materialized. During the recoating of the steel penstock, it was determined that the woodstave portion of the penstock, (not included in the original project scope), requires a preservative application in some areas where the previously applied creosote coating has deteriorated and no longer provides protecton from wood rot. Doing so will extend the life of the woodstave portion of the penstock. Whether or not to add this scope to the project is currently being evaluated.

Additional Information:

The water conveyed by the approximately five km penstock is also used by Department of Fisheries and Oceans Canada and the Comox Valley Regional District. The use by Comox Valley Regional District is expected to continue until July 2021 at which time they will complete their new intake and pipeline project and start drawing water directly from Comox Lake. Given the penstock's proximity to municipalities, and Department of Fisheries and Oceans Canada's reliance on the water conveyed by the penstock, it is important that the safety and reliability of the penstock be sustained.

<table>
<tr><td colspan="1">Investment Planning ID:
G000252</td><td colspan="2">Project Name:
Revelstoke – U1 – U4 Stator Replacement</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• Chapter 6, page 6-96
• Appendix I, Generation - line 82
• Appendix J, page 66
• BCUC IRs 1.108.1.2; 1.133.1 Confidential
• BCOAPO IRs 1.62.1 PUBLIC Attachment 1; 2.131.2
F22 RRA:
• Chapter 6, page 6-28
• Appendix I, Generation - line 52
• BCUC IR 1.45.2</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to address reliability risks associated with the Units 1 to 4 generator stator cores, stator windings and frames at the Revelstoke Generating Facility.
Refer to Appendix K – Revelstoke Facility Asset Plan for additional information.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The REV Unit 2 to 4 generators have an Asset Health Rating of Poor. The main issues leading to this rating include the poor condition of the stator windings, stator core, and rotor windings, as confirmed by poor electrical test results and visible signs of deterioration and deformation. The generator stator issues have been managed with interventions, operating restrictions and monitoring since 2007.
Unit 1 has a current Asset Health Rating of Fair; however, considering the long lead time associated with this project and the fact that all units are the same age and design, intervention on Unit 1 will be considered within the project alternatives.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
BC Hydro is considering two alternatives:
i. Replace stator components for Units 1 to 4; and
ii. Replace, Refurbish or defer intervention on a unit-by-unit basis. Refurbishment would re-wind, as opposed to replace, the stator core. Various design alternatives within this alternative have been identified.
The alternatives identified have yet to be evaluated to determine a preferred alternative.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
• Extend the life of the stator components by at least 40 years.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk	Risk Treatment
Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase.	To be determined as the project reaches Implementation Phase.
Additional Information: N/A.	

Investment Planning ID: G000543	Project Name: Seton - Canal Flow Control Structure Upgrade	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** New	

Description:

The purpose of this project is to improve the functionality of the five headworks operating gates for the Seton Canal by addressing existing deficiencies and operating concerns and by upgrading them to allow closure under flow.

Key Drivers:

- Safety
- Reputational
- Financial

Issues Being Addressed:

The five headworks operating gates at Seton Dam are required to isolate the power canal from Seton Lake Reservoir for periodic canal liner maintenance, during significant floods, or in the event of an emergency.

The canal intake gates are designed to be closed in no-flow conditions only. The inability of the gates to close under flow means that failure of the canal, aqueduct, penstock forebay, or penstock would likely result in uncontrolled flow through the canal until Seton Lake was drained to the level of the concrete dam approach channel. The uncontrolled release of water in this way could lead to loss of life and economic damage. In addition, several equipment defects have been identified with the gates' current operation. Some of the gate lifting equipment is unserviceable and a crane is used instead. The gates are difficult to close and significant leakage passing through them has been observed during recent closures.

Discussion of Alternatives:

BC Hydro is considering three alternatives:

i. **Do Nothing**: defer, either temporarily or permanently, the upgrade of the headworks operating gates. Adoption of this alternative may be acceptable if other emergency measures to control canal flows can be established;

ii. **Upgrade the Headworks Operating Gate System**: upgrade the existing gate system to address operability issues and to allow gate closure under flow; and

iii. **Replace the Headworks Operating Gate System**: design and install new gate system to address operability issues and to allow gate closure under flow.

Project Impacts and Benefits:

- Improve public safety by enabling the closure of the headworks operating gates under flow in the event of a dam safety emergency.
- Improve worker safety and reliability by addressing operability issues of the headworks operating gates for maintenance and regular operations.

[1] Start Date of Construction is the Implementation Approval Date.

Page 1 of 2

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.
Additional Information: N/A	

Investment Planning ID: G003026	Project Name: Seton – Upgrade Unit	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Identification	**Filing Reference:** F20-F21 RRA: • Chapter 6, page 6-95 • Appendix I, Generation - line 64; Appendix J, page 57 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-28 • Appendix I, Generation - line 55	

Description:

The purpose of this project is to upgrade the unit equipment to ensure safe and reliable operation at the Seton Generating Facility.

Key Drivers:

- Reliability
- Safety
- Environment
- Reputational

Issues Being Addressed:

The Seton Generating Facility is operated almost continuously except for fisheries and maintenance requirements. Both the Seton generator and turbine are original equipment (1956) and their Asset Health Rating is Poor.

Due to the age and condition of the generator and turbine there is a risk that they could fail leading to loss of generation and an extended outage. This would result in high flows down Seton River and Lower Bridge River which could cause impacts to fish and fish habitat, as well as deviations to the Bridge/Seton system operating regime. We are engaging St’át’imc Nation and regulators as part of regularly scheduled meetings to discuss flows on these two rivers, and in the event of an unplanned outage we would notify all parties to discuss how to best manage the system. Also, if water needs to be diverted through Lower Bridge River, then this could result in an increased likelihood and magnitude of spills from Terzaghi Dam to Lower Bridge River beyond the Water Use Plan Order targets for annual average flows and those same targets in settlement agreements with the St’át’imc Nation. BC Hydro is operating under a variance to our Water Use Plan order approved by the Comptroller of Water rights (February 16, 2017).

Discussion of Alternatives:

BC Hydro is considering seven alternatives:

i. **Do Nothing:** operate to failure;

ii. **Refurbish Unit with Unchanged Nameplate Rating:** It is expected that this approach could extend the unit life another 35 years;

iii. **Replace Unit with Unchanged Nameplate Rating:** It is expected that this approach would result

[1] Start Date of Construction is the Implementation Approval Date.

in a new life of 40 to 50 years; iv. **Refurbish Unit with Increased Nameplate Rating:** It is likely this approach would involve replacement of some elements of the unit and refurbishment of others, and could extend the unit life another 35 years; v. **Replace Unit with Increased Nameplate Rating:** It is expected that this approach would result in a new life of 40 to 50 years; vi. **Decommission Unit:** This alternative would see Seton being used for water passage only. The dam, canal, and intakes would be retained. The unit mechanical and electrical components would be removed or reconfigured to provide the energy dissipation needed to discharge the water safely through the powerhouse to Fraser River; and vii. **Install a Bypass with a Unit Refurbishment/Replacement:** This approach would involve refurbishing or replacing the unit as per one of the Alternatives i to v. In addition to installing a bypass past the powerhouse in a suitable location and to a suitable size to divert water from the main powerhouse during outages and/or in times of high inflows. This would allow the production of power from the bypassed water and also help to dissipate the stored energy before discharging to the Fraser River. The preferred alternative has not yet been determined.
Project Impacts and Benefits: • Improve the reliability of the Seton Generating Facility. • Improve the reliability of water conveyance capability within the Bridge River system. • Reduce the likelihood and magnitude of spills from Seton Lake Reservoir to Seton River and from Terzaghi Dam to Lower Bridge River, to minimize potential effects on fish, riparian habitat, and First Nations values. • Maintain BC Hydro's relationship with the St'at'imc Nation. • Reduce potential reputational impact due to high flow or spill events.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase.	To be determined as the project reaches Implementation Phase.

Additional Information: Some Generation P&C scope of work was not completed under Seton Upgrade Unit Protection & Control Project (GY0191) and the Seton Replace Governor Project (GM0075). This scope of work will be completed under this project.

<table>
<tr><td colspan="1">Investment Planning ID:
G000436</td><td colspan="2">Project Name:
Seven Mile - U1 - U4 Controls Upgrade</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Future</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• Chapter 6, page 6-96
• Appendix I, Generation - line 83
• Appendix K, page 39
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-28
• Appendix I, Generation - line 73</td></tr>
<tr><td colspan="3">Description:
The purpose of the project is to improve the reliability of the Units 1 to 4 control systems at the Seven Mile Generating Station.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Seven Mile generating station is categorized as a “Key” facility according to BC Hydro’s Facility Asset Plans. The control systems on Units 1 to 4 at Seven Mile Generating Station are original to the facility (installed in 1979) and have reached the end of their design life. This has resulted in an increase in forced unit outages (22 in 10 years) directly related to the poor condition of the control systems. Maintenance is becoming increasingly difficult because the required components are no longer being manufactured and the original equipment manufacturer is unable to provide technical support.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
BC Hydro considered three alternatives:
i. Do Nothing;
ii. Refurbish Units 1 to 4 controls systems; and
iii. Replace Units 1 to 4 controls systems.
Alternatives i and ii require market availability and technical support for the existing components, both of which are no longer available. Therefore, Alternative iii, replace units 1 to 4 controls systems, is the only viable alternative that will address the control system reliability concern.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
Reliable operation of the Units 1 to 4 control systems at Seven Mile Generating Station.</td></tr>
<tr><td colspan="2">Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="3">Additional Information:
N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: G004155	Project Name: Seven Mile - U1 - U3 Turbine Upgrade	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** F22 RRA: • Appendix E, page 13	

Description:

The purpose of this project is to improve the reliability of the Unit 1 to 3 turbines at the Seven Mile Generating Station.

Key Drivers:

- Reliability
- Financial

Issues Being Addressed:

The Unit 1 to 3 turbines are in Poor condition. These units have been in service for over 40 years without any major turbine overhaul or intervention. The main issues leading to a Poor Asset Health Rating include:

- Excessive runner crown and band seal erosion;
- Significant wear on the turbine shaft sleeve; and
- Runner cavitation requiring cavitation repairs every two years.

The efficiency of the units has also been reduced over time. The Unit 1 to 3 turbines weighted average efficiency was measured in 1984 at 91.0 per cent. This was lower than the original guaranteed weighted average efficiency of 92.7 per cent. It is expected that turbine efficiency has been further reduced since then, mainly because of changes in runner blade profile and runner seal erosion (seal clearance is larger than design).

Discussion of Alternatives:

BC Hydro is considering three alternatives:

i. **Do Nothing:** continue with cavitation weld repairs on turbine runners and routine inspections;

ii. **Overhaul turbines and associated components**: Restore/refurbish turbine components to “as new” condition to enable reliable operation for 25 years; and

iii. **Replace runners and overhaul turbine and associated components:** Includes overhaul scope (Alternative ii) as well as re-design and replacement of the runner and wicket gates to eliminate cavitation, achieve higher turbine efficiency and higher maximum capacity.

Project Impacts and Benefits:

- Improve reliability by resolving the runner seal erosion and runner cavitation issues.
- Reduce operations and maintenance costs by resolving the runner seal erosion and runner cavitation issues.
- Reduce the risk of turbine failure.

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.
Additional Information: N/A	

Investment Planning ID: G000525	Project Name: Strathcona Upgrade Discharge	
Forecast Capital Cost: $337.0 million to $194.4 million	**Forecast In-Service Date:** Fiscal 2027	**Start Date of Construction:**[1] Fiscal 2024
Development Phase: Definition	**Filing Reference:** F17-F19 RRA: • Appendix I, line 17, Appendix J, page 17 • BCUC IRs 1.70.3, 1.73.1, 1.73.9, 1.87.1-1.87.6, 2.249.8, 2.259.1, 2.259.2,2.260.4, BCOAPO IRs 1.36.1,1.36.2, 2.80.1, 2.80.2, 2.81.1, CEC IR 2.156.1 F20-F21 RRA: • Chapter 6, page 6-89 • Appendix I, Generation - line 15, Appendix J, page 1, Appendix K, page 1 • BCUC IR 1.115.2 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-25 • Appendix I, Generation - line 16 • Appendix P, page 25 • BCUC IR 1.45.2	

Description:

The primary purpose of this project is to provide deep reservoir drawdown capability at Strathcona Dam to mitigate dam safety risks associated with seismic events and seepage deficiencies of the dam, and to enable potential future projects to be undertaken to upgrade the dam itself if determined necessary. This capability will be provided via the selected alternative of constructing a Low Level Outlet (**LLO**) open channel on the dam's right abutment. As the LLO will include spillway functionality, the existing spillway gates will be converted to a free-crest overflow spillway that will improve the dam's ability to reliably pass high reservoir inflows.

Refer to Appendix K – Campbell River Systems Engineering Assessment for additional information.

Key Drivers:

- Safety
- Financial
- Reputational
- Environmental

Issues Being Addressed:

The Strathcona Dam is classified as an Extreme consequence category dam based on the BC Dam Safety Regulation. As such the expected seismic performance is for no uncontrolled release for the Maximum Design Earthquake with an annual exceedance frequency of once in 10,000 years. Strathcona Dam has seismic and seepage deficiencies and there is no means of enacting a deep reservoir drawdown in the event that these deficiencies manifest into damage that threatens the integrity of the

[1] Start Date of Construction is the Implementation Approval Date.

dam. Following an earthquake, there is a potential that the intake gates to the powerhouse water conduit that underlies the dam may not be able to be closed, pressurizing the conduit which may itself be damaged and lead to additional seepage through the dam. Also, there are reliability and seismic issues with the existing gated spillway that may limit its ability to operate on demand or cause it to fail following a seismic event, leading to uncontrolled release of water from the reservoir. Uncontrolled water release from the reservoir could create significant risk to life and damage to downstream residents, as water would flow downstream toward the City of Campbell River, potentially overtopping and damaging both Ladore and John Hart dams, as the Lower Campbell and John Hart reservoirs are not large enough to contain such a release. This type of event could potentially result in fatalities, financial loss and reputational damage. The provision of a new **LLO**, with a new inlet founded on a rock abutment rather than in the earth dam itself, will not only provide emergency deep drawdown of the reservoir, but will also facilitate future projects, if necessary, that would provide further safety improvements to the dam. The project scope also includes conversion of the existing gated spillway to a free-crest spillway at a higher elevation. This conversion will eliminate the need to refurbish the existing spillway gates and reinforce the existing spillway piers. Ordinary spillway functionality will be provided by sizing the LLO to allow current spillway volumes.
Discussion of Alternatives: BC Hydro considered four alternatives: i. **Construct a LLO and convert the existing spillway to a free overflow crest**; ii. **Build a seismically robust power system:** relocation of current power conduit; iii. **Rehabilitate existing dam**; and iv. **Construct a new downstream dam**. Alternative i, construct a LLO and convert the existing spillway to a free overflow crest, was selected as the preferred alternative. It provides dam safety risk reduction at the lowest cost and with the fastest delivery. The project team determined that the LLO should be the implemented first, to meet immediate dam safety needs and to enable potential future upgrades if deemed necessary to the power conduit (alternative ii) and the dam (alternative iii). Alternative iii is not feasible as a stand alone project due to the need for reservoir control during construction, but would be feasible after a new LLO is constructed. Alternative iv is not economically justified and would also require an operational LLO prior to its construction.
Project Impacts and Benefits: • Improve safety by providing a deep drawdown capability at the Strathcona Dam, so that the reservoir can be lowered and the dam unloaded in the event it suffers damage in a major earthquake or excessive seepage occurs. • Reduce potential for fatalities, financial loss and reputational impact due to an uncontrolled release of water from the reservoir in the event that the dam is damaged.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the IdentificationPhase, further developed in the Definition Phaseand finalized as the project reaches the Implementation Phase.	To be determined as the project reaches the Implementation Phase.

Additional Information: As the planning level estimate for this project is over $100 million, BC Hydro expects to submit an application to the BCUC under Section 44.2 of the Utilities Commission Act for this project. Planning is currently underway for upgrades at the downstream John Hart and Ladore facilities (John Hart Dam Seismic Upgrade Project, G000585; and Ladore Spillway Seismic Upgrade Project, G000668). Planning for these two projects is being considered in conjunction with the Strathcona Discharge Upgrade project for the following reasons:

- The projects are planned with similar and potentially overlapping construction schedules,
- The projects are relatively close geographically to one another,
- The projects have some similar scope elements that will require similar contractor expertise, and
- The projects all reside on the Campbell River and the work will need to be considered from a river system management perspective and coordinated accordingly.

Investment Planning ID: G000468	Project Name: Terzaghi - Low Level Discharge Reliability Improvement	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** F20-F21 RRA: • Appendix H, page 14	

Description:

The purpose of this project is to improve reliability and maintainability of the low-level reservoir discharge system at Terzaghi Dam so that it can be relied upon for environmental flow release, flood passage and post-earthquake operation.

Key Drivers:

- Reliability
- Environmental
- Safety

Issues Being Addressed:

The low-level outlet at Terzaghi Dam is comprised of two low-level discharge tunnels, each regulated by a downstream low-level operating gate 1 and 2 and provided with an upstream low-level maintenance gate 1 and 2. Reliable operation of the low-level operating gates is required on an ongoing basis. The low-level outlet is the primary means to provide targeted environmental flow releases downstream into the Lower Bridge River and is also required – along with the spillway – to pass the Probable Maximum Flood and for post-earthquake operation if drawdown of Carpenter Lake is required following the Maximum Design Earthquake.

The gates have failed to operate on several occasions. Subsequent troubleshooting has not been able to identify the cause. Personnel have not been able to safely access the low-level operating gates for several years as the low-level maintenance gates cannot be qualified to provide Single Device Isolation. Although a formal detailed assessment has not been conducted, the Terzaghi Dam low-level discharge system is known to have significant gaps from BC Hydro's Reliability Principles for Flood Discharge Gate Systems. In addition, post-earthquake operability of the low-level operating gates is not currently assured and is assumed to be inadequate.

Due to these design and reliability issues, there is a risk that the low-level outlet may not operate as required to regulate environmental flows into the Lower Bridge River, to pass high inflows during a flood event, or to provide reservoir drawdown capability following an earthquake.

Significant upgrades are required to improve the reliability, maintainability, and post-seismic operability of the low-level discharge system.

Discussion of Alternatives:

BC Hydro is considering two alternatives:

i. **Replace** components of the low-level discharge system: This may include a like-for-like replacement of the components at the existing location or a replacement with new equipment at a new location; and

ii. **Refurbish** components of the low-level discharge system in its existing location.

A combination of these alternatives may also be considered.

[1] Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits:	
• Improved operational reliability and maintainability of the Terzaghi Dam low-level discharge system for flood passage and for normal day-to-day environmental flow releases. • Provision of safe and reliable post-earthquake discharge and reservoir drawdown capability as required.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: N/A	

<table>
<tr><td>Investment Planning ID:
G003653</td><td colspan="2">Project Name:
Various Sites - Reservoir Booms Replacement - F2020</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• Chapter 6, page 6-89
• Appendix I, Generation - line 22
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-25 to 6-26</td></tr>
<tr><td colspan="3">Description:
The purpose of the Various Sites – Reservoir Booms Replacement project is to address the poor condition and debris retention, and inadequate public safety features of existing reservoir booms at Mica, Terzaghi, Sugar Lake, Cheakamus, Stave Falls, Clowhom and W.A.C. Bennett Dams.</td></tr>
<tr><td colspan="3">Key Drivers:
• Safety
• Risk reduction
• Operational Requirements
• Reputational</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The existing timber booms at the facilities noted above are past their intended service life, do not provide effective debris interception and retention, do not meet requirements under the Canadian Dam Association Guidelines for Public Safety, and may not have sufficient capacity to adequately protect spillways during design flow and debris conditions.
Historically, BC Hydro used booms made of timber to manage debris and to protect the public from areas of hazardous water conditions, such as near spillways and generating unit intakes. Timber booms degrade and lose freeboard (i.e., height above the waterline) over time and are prone to damage from strong winds, waves and shoreline topography.
BC Hydro developed a new steel boom after considering a variety of materials and designs and installed the first such boom at Kootenay Canal in 2018, and then at Seven Mile in 2019. The new design provides improved performance, safety features and expected asset life. This design also functions as a combined debris and public safety boom which eliminates the need for one of each at a site.
Following successful completion of those two sites, the Various Sites – Reservoir Booms Replacement project was initiated to deploy these new, more effective and longer lasting booms at other sites across the system. The project includes multiple sites to allow for efficiencies in design, procurement and construction.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
Replacement of reservoir booms was identified as a single viable alternative, based on the need for dam safety and to meet Canadian Dam Association Public Safety Guidelines. Doing nothing was not acceptable due to the condition of the existing booms, and alternative debris retention structures in reservoirs are not practical.</td></tr>
</table>

1 Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits:	
• Dam safety risks to water conveyance will be mitigated by preventing debris from impeding spillway gate operation through an enhanced design and resilience, and by replacing booms at end of life. • Public safety risks will be reduced by providing more prominent and robust barriers from areas of hazardous water conditions to boaters on the reservoir.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: N/A	

<table>
<tr><td>Investment Planning ID:
G004172</td><td colspan="2">Project Name:
Various Sites - Spillway Gate Standby Power Improvements</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Future</td><td colspan="2">Filing Reference:
F22 RRA:
• Chapter 6, page 6-25
• Appendix I, Generation - line 22
• BCOAPO IR 1.54.1</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to ensure reliability of power supply to the spillway gate systems at 13 sites by addressing the design deficiencies of the 19 existing standby power supplies through replacement or upgrade. Those 19 standby power supplies comprise six Uninterruptible Power Supply (UPS) systems and 13 diesel generators (DGs).</td></tr>
<tr><td colspan="3">Key Drivers:
• Safety
• Reliability
• Environmental
• Reputational</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Project is to address the following issues:
• The existing UPS systems are not fit for purpose as standby power sources because they are not able to function when AC power is not available; and
• The existing DGs have experienced a number of failures due to various deficiencies, including within their fuel systems and start battery circuitry.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
BC Hydro is considering two alternatives:
i. Upgrade UPS systems and DGs to reliably serve intended function as standby power sources; and
ii. Replace UPS systems and upgrade DGs.
Do nothing and Defer alternatives are not acceptable for consideration because inadequate or defective backup power at multiple facilities could lead to common cause failure of multiple spillway gates. For the existing DGs, Alternative i, upgrading is considered to be the only viable alternative as Alternative ii, replacement is unduly expensive and not appropriate for the scale of deficiencies being addressed.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
• Make standby power sources function including situations where AC power is not available.
• Minimize failures experienced on Diesel Generators.</td></tr>
<tr><td colspan="2">Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="3">Additional Information:
N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="1">Investment Planning ID:
G003554</td><td colspan="2">Project Name:
W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I, line 23,
• BCUC IRs 1.70.3, 1.85.1 to 1.85.7, 2.249.8, 2.260.4, BCOAPO IR 1.36.1
F20-F21 RRA:
• Chapter 6, page 6-89
• Appendix I, Generation - line 16, Appendix J, page 19, Appendix K, page 13
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-25
• Appendix I, Generation - line 7
• BCUC IR 1.53.1</td></tr>
<tr><td colspan="3">Description:
The primary objective of the project is to address the dam safety risks posed by the deteriorating condition of the sluiceways and slide gates on the spillway of the W.A.C. Bennett Dam. The project will also replace the existing spillway stoplogs to allow isolation of the upstream face of the spillway and spillway gates.</td></tr>
<tr><td colspan="3">Key Drivers:
• Safety
• Financial Loss
• Reputational</td></tr>
<tr><td colspan="3">Issues Being Addressed:
At the time the W.A.C. Bennett Dam was built the spillway, including the contribution from the sluiceways, was designed for flood inflows to the reservoir including those from the McGregor River Diversion. However, the McGregor River Diversion was not constructed, and is now prohibited under the Clean Energy Act. Without the McGregor River Diversion, the sluiceways are not needed to pass the Inflow Design Flood.
All nine slide gates have been inoperable since 1987 after issues with opening the gates and leakage after closure were experienced. Subsequent inspections revealed further deterioration of components of the slide gates.
The slide gate bonnet covers are in poor condition. Without remediation, there is a risk that one or more of the bonnet covers may fail, which would result in uncontrolled water release from the slide gate gallery to the drainage tunnels running below the earth filled dam. These drainage tunnels are not intended to handle such flows.
Leakage or failure of one or more of the slide gates would also result in uncontrolled water release to the</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

spillway chute, which may prevent inspection, repair and maintenance of the spillway chute.

Single device isolation certification of all nine slide gates is required to access the spillway chute for inspection and maintenance. Continued single device isolation certification will become more difficult and eventually will require refurbishment, replacement, or decommissioning of the slide gates.

Stoplogs are more generally required for maintenance and testing of spillway gates and other components, and the sluiceway construction planned for this project will require stoplogs to isolate the upstream face of the spillway from the reservoir. The existing stoplogs are in poor condition and do not provide adequate isolation to work behind. Moreover, recent tests have identified design deficiencies that make them prone to dislodging during installation and so unreliable for use. Therefore, the existing stoplogs cannot provide adequate isolation to complete the sluiceway construction work or future maintenance and testing of other spillway components.

Discussion of Alternatives:

BC Hydro considered three alternatives for the sluiceway:

i. **Do nothing:** the condition and leakage on the slide gates and bonnet covers would continue to be monitored. Decommissioning of the sluiceways or refurbishment (or replacement) of the slide gates and bonnet covers deferred into the future;

ii. **Decommission** nine sluiceways**.** The sluiceways will be plugged with reinforced concrete and the slide gate gallery would be partially filled with reinforced concrete, embedding the slide gate hydraulic cylinder assembly and bonnet covers; and

iii. **Rehabilitate** six sluiceways. This alternative recommissions two of the three sluiceways in each of the three spillway bays. The remaining sluiceways would be permanently decommissioned with a reinforced concrete plug upstream of the slide gate.

Alternative ii, decommissioning, was selected as the leading alternative because it addresses dam safety risks, minimizes lifecycle costs, and avoids future inspection and maintenance efforts. Alternative i was rejected because it does not address the dam safety issue of the deteriorating slide gate components. Alternative iii was rejected because of a lack of need for future sluiceway operation, constructability risks and future maintenance and testing requirements.

BC Hydro considered three alternatives for the stoplogs:

i. **Do Nothing**: defer replacement of the stoplogs to a future date. The stoplogs will not be able to be used for personnel protection of maintenance or capital works where isolation is required on the upstream face of the spillway;

ii. **Replace Stoplogs**: Replace the stoplogs with new semi-circular stoplogs with improved connection points and sealing; and

iii. **Remove Stoplogs and Replace with New Water Retention Structure**: Multiple alternative designs with either a traditional straight stoplog system similar to other facilities, or with a new structure upstream of the existing spillway headworks.

Alternative ii, replace stoplogs, was selected as the leading alternative because it will enable construction of the sluiceway seals as well as future maintenance and testing of other spillway components at the lowest lifecycle cost. Alternative i was rejected because the stoplogs are required to complete the sluiceway sealing work. Alternative iii was rejected because of cost and constructability issues associated with the major modifications necessary to create a traditional straight stoplog or the construction of a new structure upstream of the spillway.

Project Impacts and Benefits:

- Improve safety by addressing deteriorating condition of the sluiceways and slide gates.
- Reduce potential financial loss and reputational impact due to an uncontrolled release of water from the reservoir.

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.
Additional Information: N/A	

Investment Planning ID: G003555	Project Name: W.A.C. Bennett Dam Seal Low Level Outlets	
Forecast Capital Cost: $53.1 million to $31.6 million	**Forecast In-Service Date:** Fiscal 2026	**Start Date of Construction:**[1] Fiscal 2023
Development Phase: Definition	**Filing Reference:** F17-F19 RRA: • Appendix I, line 24; • Appendix J, page 18, • BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1 F20-F21 RRA: • Chapter 6, page 6-89 • Appendix I, Generation - line 17, Appendix J, page 21, Appendix K, page 13 • BCUC IR 1.133.1 Confidential • BCUC IR 2.253.2, 2.253.3 • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-25	

Description:

The purpose of this project is to safely decommission the three low level outlets under the W.A.C. Bennett Dam to mitigate the hazard (uncontrolled water release from the reservoir) posed by long-term deterioration of the low-level outlets.

Key Drivers:

- Safety
- Financial Loss
- Reputational

Issues Being Addressed:

The W.A.C. Bennett Dam has been classified as an Extreme consequence dam based on the BC Dam Safety Regulation. Three Low Level Outlets (**LLOs**) are located beneath the embankment dam, in rock, in the diversion tunnels that were used to divert Peace River during dam construction. The inlets to the tunnels are located at a depth of about 160 m below the surface of the maximum normal operating level of Williston Reservoir. The LLOs were designed as temporary discharge devices for use during first filling and were not intended for use as discharge devices at normal reservoir operating levels. The LLOs are currently out-of-service and regular testing and inspections are not carried out due to worker safety concerns. The condition of these assets, almost 50-years old, is deteriorating, making them a potential hazard to the dam. An uncontrolled release of water due to component structural failures would eventually result in damage to the dam and to the potential uncontrolled release of water from the reservoir, with significant risk to life, financial loss, and reputational damage if the flow was not shut off. Such a release would be very difficult to curtail given the high head and depth of the LLOs.

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives:

BC Hydro considered four alternatives:

i. **Do Nothing:** maintain the status quo or deferral;

ii. **Refurbishment** of the existing LLOs for flow release as currently designed;

iii. **Re-purposing** the LLOs for reservoir evacuation capability or for installation of additional generating units; and

iv. **Decommissioning** (either permanently or with option to re-open the LLOs some time in the future).

Alternative iv was selected as the preferred alternative. Alternative i was rejected due to the age of the LLOs and their deteriorated condition which would eventually lead to a component failure and uncontrolled release of the reservoir behind an Extreme Consequence dam. Alternative ii was rejected because no future operating scenario was identified that warrants the refurbishment of the existing LLOs for flow release as currently designed. Alternative iii was rejected because, based on an engineering study, the technical feasibility of the re-purposing option is uncertain and near-term project drivers and/or benefits were not identified.

Project Impacts and Benefits:

- Reduce safety risks by decommissioning the LLOs.
- Reduce potential for fatalities, financial loss and reputational impact due to an uncontrolled release of water from Williston Reservoir.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

N/A

Investment Planning ID: G000334	Project Name: Wahleach Refurbish Generator	
Forecast Capital Cost: $51.2 million	**Forecast In-Service Date:** Fiscal 2023	**Start Date of Construction:**[1] Fiscal 2020
Development Phase: Implementation	**Filing Reference:** F20-F21 RRA: • Chapter 6, page 6-95 • Appendix I, Generation - line 49, Appendix J, page 48, Appendix K, page 44 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-27 • Appendix E, page 14 • Appendix I, Generation - line 42 • Appendix Q, page 22	

Description:

The purpose of the project is to improve the reliability of the generator and extend the asset life by at least 40 years at the Wahleach (**WAH**) Generating Facility.

Key Drivers:

- Reliability
- Safety
- Reputational
- Environmental

Issues Being Addressed:

The Asset Health Rating for the WAH generator rotor and stator is Poor. Failure of the generator would result in an unplanned outage ranging from six to 24 months.

There is no water bypass at WAH Generating Facility, which means that if the generator is not operating the only means of evacuating water from the reservoir is by free spilling over the dam into Jones Creek. Large spills into Jones Creek may lead to erosion of the spillway channel and increases the risk of flooding the community of Laidlaw, with a risk to life, financial loss and reputational damage.

Discussion of Alternatives:

BC Hydro considered four alternatives:

i. **Do nothing**;

ii. **Rotor Pole Replacement:** Replace the rotor poles and retain the rotor spider and rim;

iii. **Generator Refurbishment:** Replace the stator and rotor poles and refurbish the remaining generator components; and

iv. **Generator Replacement:** Replace the entire generator.

Alternative iii, Generator Refurbishment, was selected as the preferred alternative because it is the most cost-effective solution based on a net present value analysis that will meet the project objectives and provide a generator life of at least 40 years. Alternative i was not selected given the deteriorated condition of the generator that will eventually lead to its failure and the possible safety, reputational and

[1] Start Date of Construction is the Implementation Approval Date.

environmental risks of spilling into Jones Creek. Alternative ii was not selected as it will not achieve the project benefit of extending the asset life by at least 40 years compared with Alternative iii. Alternative iv is not as cost-effective a solution as Generator Refurbishment in meeting the project objectives and achieving the project benefits.	
Project Impacts & Benefits: • Extend the generator life by at least 40 years.	
Project Implementation Phase Risk: Due to a generator outage extending longer than 100 days, there is a risk that flooding could occur into Jones Creek.	**Risk Treatment:** This risk will be treated by scheduling the unit outage to start in early February, which is a period of historically low inflows, to minimize spilling water and avoid potential flood damage downstream. Prior to the outage, the reservoir will be drawn down to a low level within the permissible operating range. Water flow passing technology will be piloted, if necessary, that will allow water to pass through the turbine pit while the generator installation continues; this will assist in managing the flood risk.
Additional Information: N/A	

<table>
<tr><td>Investment Planning ID:
G001047</td><td colspan="2">Project Name:
Waneta U3 Life Extension</td></tr>
<tr><td>Forecast Capital Cost:
$37.5 million</td><td>Forecast In-Service Date:
Fiscal 2023</td><td>Start Date of Construction:[1]
Fiscal 2021</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• Chapter 6, page 6-96
• Appendix I, Generation - line 71, Appendix J, page 61
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-28
• Appendix I, Generation - line 57</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to reduce the risk of failure of Waneta Unit 3 hydroelectric generator.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The primary issue being addressed is the condition of the stator winding and core. Inspections of Unit 3 stator have revealed a number of risks:
• Lamination migration – the steel laminations which form the generator stator core have come loose and are moving. This can result in physical damage to the stator winding or contact with the rotor which can result in an electrical fault;
• Loose wedges – the wedges which hold the stator winding in place in the stator core have come loose. This can result in physical damage to the stator winding which can result in an electrical fault;
• Core buckling – the steel laminations which form the generator stator core have come loose and can buckle. This can lead to physical or thermal damage to the stator laminations and winding which can result in an electrical fault; and
• Loss of circularity – the generator stator core can lose its circularity which can result in hotspots or vibrations which can lead to further damage or an electrical fault.
In addition, Unit 3 suffers from a number of issues which will be considered during this project;
• Runner cavitation – the runner experiences frequent cavitation resulting in extensive welding repairs;
• Runner cracking – extensive welding will lead to the build up of thermal stresses which, over time, can lead to cracking of the runner;
• Protection and Controls – the controls are original 1963 electromechanical relays. They are in Poor condition and contain asbestos wiring; and
• Governor controls – the existing Unit 3 governor is the original 1963 mechanical governor which has reached end of its design life. Parts and maintenance support are limited.</td></tr>
</table>

1 Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">

Discussion of Alternatives:

BC Hydro considered the following four alternatives:

i. **Do nothing:** Replace the stator winding, stator core at failure;

ii. **Re-wedge:** the stator winding;

iii. **Re-stack:** the stator; and

iv. **Replace:** the stator core and windings.

Alternative iv, replace the stator core and windings with a modern design, was chosen as the lead alternative as this is the only alternative that would address the root causes of the major defects reported with the stator.

In addition, the downtime required to address the stator yields the opportunity to replace other major components that are in poor condition and have reached end of life. These components include the runner, governor controls, unit transformer, wicket gates and protection and controls.

</td></tr>
<tr><td colspan="2">

Project Impacts and Benefits:

- Improved reliability of the generator.
- Reduced operating and maintenance costs of the generator.

</td></tr>
<tr><td>

Project Implementation Phase Risk:

- There is a risk of schedule delays due to COVID-19 shipping delays.
- There is also a risk of project cost increase due to commodity price increases (lumber and steel).

</td><td>

Risk Treatment:

- Logistics teams are booking transport as earlier as possible
- There is only a small portion of the scope with materials price exposure (switchgear mezzanine, temporary construction). Therefore, commodity price increase is expected to have a low impact.

</td></tr>
<tr><td colspan="2">

Additional Information:

On July 26, 2018, BC Hydro became the sole owner of Waneta. Teck Metals Ltd (**TML**) continues to act as the Operator of the facility during the 20-year lease term. In that role, Teck is required to operate, manage, and maintain Waneta in accordance with the terms of the Co-Possessors and Operating Agreement (**COPOA**), which includes capital planning and operating to a prudent owner standard, exercising the degree of care and skill of an experienced dam operator and acting in accordance with Good Utility Practice.

There are a number of projects that TML has agreed to complete as detailed in Schedule C of the COPOA, including this Unit 3 Life Extension project. As Operator at Waneta, TML will oversee the execution of the project and will provide regular updates to BC Hydro's Operating Committee representatives.

BC Hydro will retain an oversight role as part of the Waneta Operating Committee, including reviewing the annual operating plans for Waneta; however, as TML is the Operator of Waneta, processes that BC Hydro generally uses for internal asset management and planning purposes will not be applied.

</td></tr>
</table>

<table>
<tr><td colspan="2">Investment Planning ID:
901474</td><td colspan="2">Project Name:
2L003 and 2L049 – Transmission Line Crossing Seismic Upgrade (Second Narrows)</td></tr>
<tr><td colspan="2">Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td colspan="2">Development Phase:
Future</td><td colspan="2">Filing Reference:
New</td></tr>
<tr><td colspan="4">Description:
The steel lattice transmission towers that carry 230 kV circuits 2L003 and 2L049 across Burrard Inlet at the Second Narrows crossing support an important transmission connection for serving load in the Metro Vancouver area. This project will upgrade the seismic reliability of the 2L003 and 2L049 crossing.</td></tr>
<tr><td colspan="4">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="4">Issues Being Addressed:
The 2L003 and 2L049 crossing structures have been assessed as being critical, and at risk of sustaining damage, including possible collapse, during an earthquake of less than 1:475-year frequency. Loss of the transmission line crossing would result in load curtailment in the Metro Vancouver area and overloading on the alternative load paths of 2L50 and 2L51. This project will upgrade the seismic reliability of the 2L003 and 2L049 crossing to withstand a 1:475 return period earthquake and increase the seismic reliability of supply into Vancouver and Burnaby. This project will also mitigate the impact of losing the underground cables on 2L50 and/or 2L51 from a seismic event.</td></tr>
<tr><td colspan="4">Discussion of Alternatives:
BC Hydro is considering three alternatives:
i. Upgrade: This alternative is to seismically upgrade the transmission crossing, including ground improvements, foundation reinforcements and structural upgrades;
ii. New Crossing: A feasible alternative would be to string new conductors on a new alignment across the river by constructing a new steel structure upslope of existing structure 688 including ground improvements, piling works and removal of the existing structure; and
iii. Submarine Crossing: The installation of a submerged cable across the Narrows, using horizontal directional drilling for all or part of the route.</td></tr>
<tr><td colspan="4">Project Impacts and Benefits:
• Improved seismic reliability to continue to serve the Metro Vancouver load after a major earthquake.</td></tr>
<tr><td colspan="3">Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="4">Additional Information:
N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="1">Investment Planning ID:
901002</td><td colspan="2">Project Name:
2L146 – Cable Replacement</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• Chapter 6, page 6-116
• Appendix I, Transmission - line 62, Appendix J, page 113
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-52
• Appendix I, Transmission - line 59</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to address reliability and environmental risks associated with the poor asset health of 2L146 cable. A replaced cable will have higher capacity to serve Southern Vancouver Island load growth.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Environmental</td></tr>
<tr><td colspan="3">Issues Being Addressed:
Circuit 2L146 is a 230 kV direct buried oil-filled cable that runs 7.1 km between Horsey substation and Goward substation in Victoria. It has been in service since 1976 and has a history of leaks. The cable is in proximity to environmentally sensitive areas including fish habitat and salmon spawning grounds. Continued oil leaks could have ecological impact on such sensitive areas, and impact community-based restoration efforts targeted to improve the habitat value. In recent years, there have been at least seven leaks, including one which resulted in oil contaminating Colquitz Creek. Many of the joints were also gassing, thus requiring replacement; more replacements are expected to be required in the future.
In addition, 2L146 was identified as being at high risk for failure during an earthquake in a 2014 seismic review. Currently, the cable has an Asset Health Index score of Very Poor. Failure of this cable would mean that Goward, Horsey, or Esquimalt substations would be reliant on a single circuit and would be at risk of total station outages for six weeks to one year if a concurrent outage occurred on any one of the other circuits supplying this area (2L143, 2L144 or 2L145). This represents up to 375 MVA of load in the Victoria area at risk in the event of a concurrent outage on any of the other circuits.
Based on load forecasts for the Southern Vancouver Island region and a desire to prevent overloads on existing circuits, the existing 2L146 cable will not provide sufficient capacity to meet the local load following a single contingency event after fiscal 2030. This would result in load shedding in the Victoria area.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives: Three alternatives were evaluated: i. **Do nothing / deferral:** This option would defer the replacement of the cable for five years, which may lead to an ongoing risk of oil leaks and system risks, leading a reactive replacement; ii. **Replace:** Replace the existing cable with a new cable with the existing rating installed in a new duct bank to improve maintainability and mitigate seismic risks. Solid dielectric insulation would eliminate the use of oil and the risk of future oil leaks; and iii. **Upgrade: Same as the Replace alternative but with** a new cable capable of meeting load growth in the future. Alternative iii, Upgrade the cable, was selected as the Single Viable Alternative for the project that will meet expected future load growth. The increased risk of circuit failure under Alternative i would leave Horsey and other Victoria substations with diminished reliability for extended periods. Alternative ii does not address the overload issues expected in the future.
Project Impacts & Benefits: • Improve reliability associated with Very Poor asset health. • Reduce environmental risks associated with the 2L146 cable. • Ensure that future load growth can be met.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information: N/A

Investment Planning ID:	Project Name:	
94035	5L063 Telkwa Relocation	
Forecast Capital Cost: $66.4 million	**Forecast In-Service Date:** Fiscal 2024	**Start Date of Construction:**[1] Fiscal 2021
Development Phase: Implementation	**Filing Reference:** F17-F19 RRA: • Appendix I, line 45, • Appendix J, page 71 • BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1 F20-F21 RRA: • Chapter 6, page 6-117 • Appendix E, page 14 • Appendix I, Transmission - line 66, Appendix J, page 116 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-53 • Appendix I, Transmission - line 64	

Description:

The purpose of the project is to continue reliable transmission of electricity on 5L63 by relocating the line segment currently situated in an active landslide area.

Key Drivers:

- Safety
- Reliability

Issues Being Addressed:

Northwest British Columbia, including the communities of Prince Rupert, Terrace, Kitimat and Smithers are interconnected by a series of 500 kV transmission lines: 5L61, 5L62 and 5L63. Circuit 5L63, built in 1973 / 74 is a 500 kV radial transmission line between Telkwa substation and Skeena substation. As a radial feed, the reliability of this line is essential for this large region of the province.

The line crosses an unstable area of land, known as the “Bulbous Toe”, which has been slowly sliding for approximately 35 years and has caused a tower on the line to be displaced by 15 cm to 44 cm annually. BC Hydro has been monitoring this area, which is a large, deep slide approximately three km long and 1.5 km wide at its widest point and impacts approximately 1.4 km of the line. Over time, the tower has moved approximately eight meters placing increased stress on conductors and local structures. It is no longer possible to adjust guy wires and insulator strings to compensate for its movement resulting in flashover risk or catastrophic failure of the line. The continued movement of the tower is a safety concern for personnel who are performing maintenance on the system. There is potential for the slide to accelerate or release in a single catastrophic event involving hundreds of cubic meters of debris that would wipe out the tower and result in an extended outage.

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">Discussion of Alternatives:
BC Hydro considered four alternatives:
i. Do nothing and continue to maintain;
ii. Defer through risk mitigation;
iii. Do nothing but acquire spares and pre-plan an emergency response; and
iv. Relocate 5L63 away from landslide area.
Alternative iv, relocate 5L63 away from landslide area, was selected as the Single Viable Alternative to meet the project objectives. The other alternatives would not address the reliability risks and safety risks.</td></tr>
<tr><td colspan="2">Project Impacts and Benefits:
• Improve the reliability of 5L63 and the supply to the large region of the province that it serves.
• Address safety risks associated with the section of 5L63 in the “Bulbous Toe” landslide area.</td></tr>
<tr><td>Project Implementation Phase Risk:
Due to the unstable slopes and earth flows in the project area, there is a risk that towers on unstable soil may get displaced prior to the project in service date. This may result in a prolonged forced outage of 5L63.</td><td>Risk Treatment:
The treatment plan is to install dead end structures on either side of the Bulbous Toe landslide to prevent cascading failure of 5L63 and a longer outage should a landslide occur prior to the full relocation route being constructed.</td></tr>
<tr><td colspan="2">Additional Information:
BC Hydro is targeting completion of the project for September 2023 to accommodate customer load interconnection requirements.</td></tr>
</table>

<table>
<tr><td>Investment Planning ID:
900575</td><td colspan="2">Project Name:
Barnard 50/60 Feeder Section Replacement</td></tr>
<tr><td>Forecast Capital Cost:
$47.9 million</td><td>Forecast In-Service Date:
Fiscal 2023</td><td>Start Date of Construction:[1]
Fiscal 2019</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I, line 46
• Appendix J, page 72
• BCUC IRs 1.70.3, 2.249.8, 2.264.4, BCOAPO IR 1.36.1

F20-F21 RRA:
• Chapter 6, page 6-111
• Appendix I, Transmission - line 25, Appendix J, page 98, Appendix K, page 48
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1

F22 RRA:
• Chapter 6, page 6-35 and 6-45
• Appendix I, Transmission - line 20</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to replace the 12 kV Feeder Section 50/60 series, 230 kV and 12 kV protection and control equipment and telecommunication assets at Barnard Substation.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Safety</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Barnard substation 50/60 feeder section equipment, installed between 1950 and 1955, has reached end of life, resulting in increased reliability and safety risk. The Asset Health Index rating on the electrical equipment in the feeder section (e.g., bulk oil breakers and disconnect switches) is Very Poor. Failures may cause safety hazards and potentially long outages to impacted feeders. The design of the feeder section is obsolete and there are clearance issues associated with the equipment leading to increased safety risks. Maintenance work cannot be performed safely without significant time and expense to offload feeders.
The identified 230 kV and 12 kV protection and control and telecommunication equipment in the substation is over 50-years old and has reached end of life and needs replacement.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
BC Hydro considered two alternatives:
i. Replace Feeder Section 50/60 and replace aging protection, control and telecommunication equipment; and
ii. Do Nothing.
Alternative i, replace Feeder Section 50/60 and replace aging protection, control and telecommunication equipment, was selected as the preferred alternative. This was the Single Viable Alternative that met the project objectives of addressing the reliability risk of the end-of-life equipment and minimizing worker safety risks.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits: • Improved reliability for customers served through the Barnard Substation. • Improved worker safety.	
Project Implementation Phase Risk: Due to limited information on existing underground infrastructure, duct bank design may need to be modified during construction leading to increased cost and a potential schedule delay.	**Risk Treatment:** Perform underground surveys to verify the locations of the utilities, to the extent possible, before completing the design. Use methods such as hydro vacuuming ahead of excavation to verify locations and, if required, modify the design.
Additional Information: N/A	

Investment Planning ID: 900247	Project Name: Bridge River – T4 Transformer Replacement	
Forecast Capital Cost: $48.1 million to $27.7 million	**Forecast In-Service Date:** Fiscal 2023	**Start Date of Construction:**[1] Fiscal 2022
Development Phase: Definition	**Filing Reference:** F20-F21 RRA: • Chapter 6, page 6-111 • Appendix I, Transmission - line 29, Appendix J, page 99 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-45 • Appendix I, Transmission - line 26	

Description:

The purpose of this project is to improve the reliability and environmental risks, associated with the T4 Transformers (**T4**) at Bridge River Terminal (**BRT**).

Key Drivers:

- Reliability
- Environmental

Issues Being Addressed:

At BRT, the T4 Phases A and B, as well as the spare at BRT substation are all approaching end of life. The Asset Health Index for Phases A and B are Poor. A significant failure of these phases could cause an extended reduction in the ability to transmit power from BRT.

T4 does not have oil spill containment or fire protection for any of the transformer phases, and therefore a catastrophic failure of T4 may result in an uncontrolled release of transformer oil into the environment. In the event of an unplanned outage of T4 there is a risk that generation would need to be curtailed from the Bridge River Generating Facility and Independent Power Producers connected to Upper Harrison Terminal. Curtailing generation may result in spilling water at Terzaghi Dam into Lower Bridge River that could affect fish and fish habitat.

Discussion of Alternatives:

BC Hydro considered four alternatives:

i. **Replace T4A with refurbished T4D, refurbish T4B, obtain a new phase T4D for use as a spare transformer**;

ii. **Replace T4A and T4B with new single-phase transformers, refurbish T4D for use as a spare transformer**;

iii. **Replace all three phases of T4 with a new three-phase transformer, obtain an additional new three-phase transformer as a spare**; and

iv. **Deferral of the project for a period of up to five years**.

Alternative ii "Replace T4A and T4B with new single-phase transformers, refurbish T4D for use as a spare transformer" was selected as the preferred alternative as it will address the project objectives of improving reliability and reducing the likelihood of high water levels at Terzaghi Dam during an unplanned outage. Compared to Alternative i, Alternative ii has lower constructability risk due to not refurbishing old equipment. Compared to Alternative iii, Alternative ii has lower constructability risk and less potential

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">archeological impact because it does not require deep foundations. Alternative iii also has higher transportation risk due to the size of the three-phase transformer. Alternative ii had slightly higher worker safety risk than Alternative iii; however, this risk can be mitigated with a robust worker safety plan. Environmental risks due to an unplanned outage were too great for BC Hydro to accept Alternative iv.</td></tr>
<tr><td colspan="2">Project Impacts and Benefits:
• Improved reliability of transformer T4 at BRT reduces the outage risk</td></tr>
<tr><td>Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase.</td><td>Risk Treatment:
To be determined as the project reaches Implementation Phase.</td></tr>
<tr><td colspan="2">Additional Information:
N/A</td></tr>
</table>

<table>
<tr><td colspan="1">Investment Planning ID:
92423</td><td colspan="2">Project Name:
Bridge River Transmission Project</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• Chapter 6, page 6-102
• Appendix I, Transmission - line 5, Appendix J, page 75, Appendix K, page 50
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-36
• Appendix I, Transmission - line 3
• BCUC IR 1.45.2</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to increase current-carrying capacity of the Bridge River Transmission System to address system constraints caused by increase in generation in the Bridge River area. In addition, the project will address asset health issues to improve the reliability and safety of the 2L90 circuit.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Environment
• Financial Loss
• Reputational</td></tr>
<tr><td colspan="3">Issues Being Addressed:
Generation from the Bridge River System[2] and several nearby IPPs[3] is transmitted through three regional transmission paths towards the Lower Mainland load centre. By 2022, approximately 400 MW of IPP generation is expected to be connected to the Bridge River Transmission System. While BC Hydro’s Bridge River 1 and 2 Generating Stations have been derated over the past decade, BC Hydro is now investing in these units to restore their capacity. Units 5 and 6 at the Bridge River 2 Generating Station were replaced in fiscal 2019 and fiscal 2020, respectively. Generating Units 7 and 8 at the Bridge River 2 Generating Station are being replaced in fiscal 2021 and fiscal 2022. The Bridge River 1 Project will replace Units 1 to 4 at the Bridge River 1 Generating Station. Collectively, these projects will restore the overall capacity of the Bridge River Facility to 532 MW.
During freshet and summer months when generation output is high and local load is low, the 2L90 circuit</td></tr>
</table>

1 Start Date of Construction is the Implementation Approval Date.

2 The Bridge River System consists of the La Joie Generating Station, Bridge River 1 and Bridge River 2 Generating Stations, and Seton Generating Station.

3 IPPs on these paths include: the Kwalsa projects, Upper Stave River, Northwest Stave River, Trethewy Creek, and Big Silver, all of which connect at the Upper Harrison Terminal; Rutherford Creek, Ashlu Creek, Fitzsimmons Creek, Upper Lillooet, and Boulder Creek, all of which connect along the Sea-to-Sky corridor; and Hunter Creek, which connects at Hope. Another IPP, Bremner Trio Hydro, is currently under construction and expected to connect to the Bridge River Transmission System at the Upper Harrison Terminal Station.

would become overloaded, and would cause the 2L90 circuit to exceed its thermal limits, potentially leading to overheating, thermal damage and unsafe clearances. These transmission constraints require generation curtailment in response to high ambient temperatures.

In addition, the 2L90 circuit also has asset health defects and issues that need to be addressed. Defects that are not addressed will eventually lead to line de-rating as well as electrical, structural and/or mechanical failures. This could result in unplanned outages, as well as worker and public safety risks.

Discussion of Alternatives:

BC Hydro considered three alternatives:

i. **Increase the capacity of the 2L90 Circuit including refurbishment of the 2L90 circuit**;

ii. **Increase the capacity of the T1 transformer at Rosedale (ROS) Substation** and refurbish and restore the 2L90 circuit; and

iii. **Curtail IPP generation** and refurbish and restore the 2L90 circuit.

Alternative i, increase the capacity of the 2L90 Circuit, was selected as the leading alternative because it has the lowest present value of lifecycle cost relative to the competing alternatives, and the incremental environmental and archaeological impacts are expected to be addressed through mitigation and avoidance measures developed throughout the Feasibility Design stage, informed through engagement with Indigenous communities.

Project Impacts and Benefits:

- Increase maximum capacity of the Bridge River Transmission System to meet the higher generation demands of the area.
- Reduce financial losses associated with generation curtailment.
- Maintain BC Hydro’s relationship with the St’at’imc Nation.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase	To be determined when the project reaches Implementation.

Additional Information:

In October 2020, the BCUC issued its decision on BC Hydro’s Fiscal 2020 to Fiscal 2021 Revenue Requirements Application. In Directive 29 of the Decision, it directed BC Hydro to file a joint CPCN for both the Bridge River 1 Units 1 to 4 Generator Replacement Project and the Bridge River Transmission Project. In accordance with this directive, BC Hydro will file a joint CPCN application in summer 2021.

<table>
<tr><td>Investment Planning ID:
93788</td><td colspan="2">Project Name:
Capilano Substation Upgrade</td></tr>
<tr><td>Forecast Capital Cost:
$87.4 million</td><td>Forecast In-Service Date:
Fiscal 2025</td><td>Start Date of Construction:[1]
Fiscal 2020</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
Amended F12-F14 RRA:
• Application: Amended Appendix I, page 18;
• Amended Appendix J, page 125
• BCUC IR 1.204.1 Attachment 1
F2014 Annual Report:
• Appendix I, line 113;
• Appendix J, page 41.
F17-F19 RRA:
• Appendix I, line 36, Appendix J, page 63
• BCUC IRs 1.70.3, 2.249.8, 2.253.2, 2.260.4, BCOAPO IR 1.36.1
F20-F21 RRA:
• Chapter 6, page 6-104
• Appendix I, Transmission - line 12, Appendix J, page 87, Appendix K, page 51 and 69
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-40 to 6-41
• Appendix I, Transmission - line 11</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to improve the reliability and reduce the safety risks at Capilano substation.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Safety</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Capilano substation is over 60 years old and most of its major equipment is near end of life and needs immediate replacement. In particular, the 60 kV bulk-oil and 12 kV air-blast circuit breakers are obsolete and pose worker safety and reliability risks. The Asset Health Index of key equipment in the station such as the Protection and Control System, Instrument Transformers and Disconnect Switches is rated as Poor or Very Poor. In addition, the existing feeder section buildings do not meet current seismic standards and the equipment inside one of the buildings does not meet required safe electrical working clearances.
The new Capilano substation will provide 25 kV distribution voltage. The existing 12 kV substation will be decommissioned after the surrounding service area has been converted to 25 kV operation which is planned to align with the construction of the new substation.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives:

BC Hydro considered four alternatives:

i. **Do Nothing**;

ii. **Upgrade: upgrade the** existing Capilano substation;

iii. **Replace: replace the** Capilano substation on new property; and

iv. **Defer: defer the** project beyond fiscal 2022.

Alternative ii, upgrade the existing Capilano substation, was selected as the preferred alternative as it meets the project objectives. Alternative iii was not selected because it would be more costly and have schedule delay risks compared to Alternative ii because of the additional scope to find a new property and realign two transmission lines. Alternatives i and iv were not selected as doing nothing, or deferring, would not address the current rating of Poor or Very Poor for most of the substation equipment that is near the end of life.

Project Impacts and Benefits:

- Improved reliability for the North Vancouver area through addressing aging equipment concerns.
- Reduced worker safety risks caused by electrical working clearances and seismic issues.

Project Implementation Phase Risk:	**Risk Treatment:**
Due to possible opposition to the rebuild at Capilano substation by stakeholders, including local residents and the District of North Vancouver, as a result of a number of issues such as tree removal, perceived impacts to private property, access to local parks/trails, and the potential for increased noise and dust levels during construction, there is a risk of incurring project delays and increased costs.	This risk is treated through an enhanced stakeholder consultation and communication plan, involving project signage and regular scheduled meetings with the District of North Vancouver.

Additional Information:

N/A

Investment Planning ID: 92910	Project Name: Clayburn Substation Upgrade	
Forecast Capital Cost: $35.7 million	**Forecast In-Service Date:** Fiscal 2024	**Start Date of Construction:**[1] Fiscal 2021
Development Phase: Implementation	**Filing Reference:** F17-F19 RRA: • Appendix I, line 37 • BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1 F20-F21 RRA: • Chapter 6, page 6-104 • Appendix I, Transmission - line 14, Appendix J, page 91, Appendix K, page 46 and 51 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-40 • Appendix I, Transmission - line 13	

Description:

The purpose of this project is to upgrade the Clayburn (**CBN**) substation to reduce safety risks and increase the capacity from 180 MVA to 200 MVA, which serves the load in the Abbotsford area and enables the decommissioning of the Sumas Way (**SMW**) substation.

Key Drivers:

- Reliability
- Safety

Issues Being Addressed:

The Abbotsford area is currently supplied by the Mount Lehman (**MLE**), CBN, Gloucester, and SMW substations. At present, the total capacity of these four stations is 360 MVA. The general strategy for the area is to upgrade the MLE substation, upgrade and address safety issues at the CBN substation, and after the capacity upgrades, decommission the SMW substation.

At CBN substation, the existing 25 kV feeder sections are outdoor compact air insulated switchgear with inadequate clearances to energized equipment. These require extended outages for routine operation and maintenance. However, opportunities to take the required outages at CBN substation have been very limited due to the unacceptable impact on customers. As a result of the safety issues associated with performing work, coupled with the challenges with finding appropriate outage times, maintenance on the CBN substation feeder sections has been postponed indefinitely.

Upgrading the CBN substation to 200 MVA is required to enable decommissioning of the SMW substation. SMW has increased reliability risks due to degrading asset condition and has elevated safety risks due to the non-arc resistant metalclad design of the 25 kV feeder section.

Discussion of Alternatives:

This project was identified as a result of a 30-year study carried out for the Abbotsford area in 2013 to mitigate safety issues at SMW and CBN substations and address capacity shortage in the Abbotsford area. The area study resulted in three alternative solutions being identified and reviewed. The alternatives compared different implementation strategies to determine not only what should be done, but also the

[1] Start Date of Construction is the Implementation Approval Date.

timing.

BC Hydro considered three sets of alternatives for the Abbotsford area strategy:

i. Expand MLE in the First Phase;
Reinforce CBN in the Near Term and Expand in the Future; and
Decommission SMW in the Near Term.

ii. Expand MLE in the Future;
Reinforce CBN in the Near Term and Expand in the Future; and
Expand SMW in the First Phase and Replace Metalclad in the Near Term.

iii. Expand MLE in the Future;
Expand CBN in the Near Term; and
Decommission SMW in the Near Term.

Alternative i was accepted as the overall strategy as it was technically superior to Alternative iii, and more cost effective that Alternative ii. The MLE Substation upgrade to 150 MVA in the first phase will address the issues and meet the objectives of the overall Abbotsford area strategy. The MLE Substation upgrade is less expensive than the other alternatives, provides sufficient capacity to supply the area's needs for 6 years longer than the other alternatives, has the lowest transmission reinforcement costs and system losses, and facilitates the important migration of load from the constrained Fraser Valley 60kV systems to the more robust Fraser Valley 230kV systems.

To deliver this selected strategy three phases of upgrades and four major projects were advanced:

First Phase:

i. MLE Substation upgrade to 150 MVA;

Second Phase:

ii. CBN Substation upgrade to 200 MVA (this project);

iii. SMW Substation decommissioning; and

Third Phase:

iv. CBN Substation upgrade to 300 MVA.

The CBN Substation upgrade to 200 MVA project is the Single Viable Alternative that meets the objectives of the accepted overall strategy for the Abbotsford area.

Project Impacts & Benefits:

- Improved reliability in the Abbotsford area by increasing the capacity of CBN substation to 200 MVA.
- Improved safety at CBN substation.
- Increasing the capacity of MLE and CBN to service the Abbotsford area will facilitate the decommissioning of the SMW substation as this is the most cost-effective way to address the safety risks at this substation.

Project Implementation Phase Risk:	**Risk Treatment:**
Due to the need to work within an energized substation there is a risk of violating the limits of approach that could result in a worker injury or fatality.	To mitigate this risk, BC Hydro safe work procedures including emergency plans will be followed, including signage, training, flagging and isolation. Construction activities will be staged according to outages to ensure workers are completing tasks in de-energized areas. Safety watcher will be utilized, as required.

Additional Information:

N/A

Investment Planning ID: 900266	**Project Name:** East Vancouver - Substation Construction	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** F20-F21 RRA: • Chapter 6, page 6-102 • Appendix I, Transmission - line 7, Appendix J, page 79, Appendix K, page 54 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Appendix E, page 14 • BCUC IR 1.47.1 and 1.47.2 • CEC IR 1.39.2.1	

Description:

This project will build a new 230/12 kV – 25 kV, 400 MVA (ultimate capacity) station in the Eastside/Strathcona neighbourhood of Downtown Vancouver as part of the second stage of the 30-year Downtown Vancouver Electricity Supply Plan.

Key Drivers:

- Reliability

Issues Being Addressed:

The Downtown Vancouver area is comprised of the Downtown, West End, Strathcona, and Grandview-Woodland neighbourhoods. The area is supplied by a 230 kV and 69 kV transmission network and three substations:

- Cathedral Square substation (built in 1984);
- Dal Grauer substation (built in 1953); and
- Murrin substation (built in 1947).

There are number of risks and issues at the ageing Dal Grauer and Murrin substations. More than half of the assets are expected to degrade to an Asset Health of Poor or Very Poor in the next 10 to 20 years, presenting a reliability risk. Murrin substation is on seismically unstable soil. Approximately half of the 230 kV switchyard, which supplies both Murrin and Dal Grauer loads, is vulnerable to severe earthquake damage from liquefaction and settlement.

The long-term strategy for the area is to mitigate the above reliability and safety risks by replacing Murrin and Dal Grauer substations with new substations. One of these is the new East Vancouver Substation.

Discussion of Alternatives:

The ultimate capacity of the East Vancouver substation will be 400 MVA, located in the Strathcona neighbourhood of Vancouver. The project will consider different options for the initial size of the substation when it is first constructed, given that the 400 MVA capacity will not be required immediately.

[1] Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits:	
• Improve East side/Strathcona Vancouver area reliability. • Minimize worker safety risks in the area.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: Related project: West End - Substation Construction and System Reinforcement (Investment Planning ID: 900598)	

Investment Planning ID: 94057	Project Name: Gulf Islands - Transmission Reinforcement	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** F20-F21 RRA: • Chapter 6, page 6-116 • Appendix H, page 14 • Appendix I, Transmission - line 63, Appendix J, page 115, Appendix K, page 77 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-52 • Appendix E, page 14 • Appendix I, Transmission - line 60	

Description:

The substations on the Gulf Islands, Saltspring (**SAL**) Substation and Galiano (**GLS**) Substation, are supplied from Arnott (**ARN**) Substation on the mainland and the Vancouver Island Terminal (**VIT**) on Vancouver Island by circuit 1L18. In service since 1958, 1L18 is a hybrid circuit of overhead lines and submarine cables.

The 1L18 cables that lie in the Georgia Strait and Trincomali Channel are approaching end-of-life with inspections identifying major concerns, resulting in the cables being assigned a Poor asset health rating with a high risk of mechanical failure. Failure of these cables will compromise energy reliability, resulting in extended outages to the Gulf Islands. Repair of the aging cables after a failure would be a significant unplanned sustainment cost, and would be of limited value since the repair would be at best temporary and depending on the mode of failure the repair could be potentially not possible, forcing an emergency cable replacement project. BC Hydro is proposing to reinforce the transmission supply to the Gulf Islands to mitigate for the 1L18 cable end-of-life condition and reduce the reliability risk in the event of a 1L18 failure.

Key Drivers:

- Reliability

Issues Being Addressed:

The most recent inspections of 1L18 show severe damage to its armor at key locations in the Georgia Strait at points where tidal currents cause the cable to rub against the rocky seabed. In this state, the cables are at a high risk of mechanical failure (causing an outage, and environmental risk from oil leaks). Further, the circuit is also expected to fail if a moderate earthquake were to occur in these locations. If the cables fail, the energy supply to the Gulf Islands will be compromised and extended outages are expected as secondary services are currently insufficient.

The desired outcome of the project is to continue to supply the load in the Gulf Islands with improved levels of reliability and mitigate seismic risk to the Gulf Islands energy supply.

[1] Start Date of Construction is the Implementation Approval Date.

Page 1 of 2

Discussion of Alternatives:

BC Hydro is considering two alternatives:

i. **Tap 2L129 in the Gulf Islands:** This alternative involves constructing a tap from 2L129 into SAL substation and provides a second supply in the event 1L18 fails. This will require the upgrade of the station to 230 kV, including the installation of a new transformer and breaker. In addition, a shunt capacitor and thermal upgrades on Vancouver Island will be needed due to the increased energy flows and power factor correction in the system. This will address the immediate supply concern with the 1L18 cable condition and reliability but defer addressing the eventual replacement of the 1L18 cables to a future project that will address load growth on Vancouver Island; and

ii. **Construct Additional 138 kV overhead line from VIT to SAL:** This alternative will construct a new 138 kV overhead transmission line (about 16 km in length) using existing rights of way from VIT to SAL substation, in order to provide a second supply to SAL substation. Similar to Alternative i, this will require a new line position, and the installation of a shunt capacitor and thermal upgrades at VIT.

Project Impacts and Benefits:

- Improved energy reliability to Gulf Island communities as 1L18 approaches end-of-life.
- Mitigate the risk of 1L18 failure as there will be a secondary energy path to supply the Gulf Islands.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

Eventual replacement of the 1L18 cables will be deferred to a future project to address supply to Vancouver Island.

Investment Planning ID: 900268	Project Name: Horne Payne - Feeder Section Addition	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** New	

Description:

This project will add a new 50 MVA, 25 kV gas insulated feeder section to the existing 25 kV gas insulated feeder section building at Horne Payne substation.

Key Drivers:

- Reliability

Issues Being Addressed:

The 12 kV feeder section at Lougheed and the 12 kV, 50/60 series feeder section at Horne Payne are aging and approaching end of life presenting a reliability risk. As these assets reach end of life they are being decommissioned, and the load transferred to the existing 25 kV gas insulated feeder section building at Horne Payne. These load transfers, along with natural load growth in the area, are driving the need for additional feeder section capacity in the 25 kV switchyard at Horne Payne.

Discussion of Alternatives:

BC Hydro is considering two alternatives:

i. **Add a 25 kV gas insulated feeder section:** Add 6 feeder positions in the existing gas insulated feeder section building at Horne Payne. This alternative addresses the reliability risk associated with end-of-life equipment and the station exceeding capacity as well as the long-term plan to convert area distribution system to 25 kV; and

ii. **Do nothing:** this alternative does not address the issues identified above.

Project Impacts and Benefits:

- Improve North Burnaby area reliability.

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

N/A

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: 93731	Project Name: Jordan River – Switchyard Upgrade	
Forecast Capital Cost: $43.6 million	**Forecast In-Service Date:** Fiscal 2023	**Start Date of Construction:**[1] Fiscal 2020
Development Phase: Implementation	**Filing Reference:** F20-F21 RRA: • Chapter 6, page 6-111 • Appendix I, Transmission - line 31, Appendix J, page 101 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-45 • Appendix I, Transmission - line 23	

Description:

The purpose of the project is to reconfigure and replace aging equipment at the Jordan River (**JOR**) switchyard to address reliability, safety, environmental, and seismic deficiencies.

Key Drivers:

- Reliability
- Safety
- Environmental

Issues Being Addressed:

The JOR switchyard is 50 years old and the majority of its equipment is nearing end-of-life. The switchyard does not meet current safety, environmental and seismic standards. In particular, transformers Transformer 1 (**T1**) and Transformer 2 (**T2**) have numerous deficiencies, including the lack of monitoring gauges, lack of effective cooling, leaking bushings and significant oil leakage with no oil containment. T2 is being closely monitored due to elevated levels of combustible gasses which caused an outage in 2015. T1 and T2 are unique transformers with no system spare. In addition, the present layout of the switchyard is deficient as there is insufficient clearance between major equipment which increases safety and reliability risks.

Discussion of Alternatives:

BC Hydro considered five alternatives:

i. **Like for like replacement** of end of life equipment (not viable);

ii. **Transformer replacement with separate distribution** transformers (not viable);

iii. **Transformer replacement and switchyard expansion**;

iv. **Single-phase step-up transformers**; and

v. **Transformer replacement and switchyard expansion and new pad mount distribution transformers.** The two step-up transformers will be replaced, and a portion of the switchyard will be rebuilt. Distribution voltage connection would be through two new pad mounted transformers.

Alternative v, Transformer replacement and switchyard expansion and new pad mount distribution transformers, was selected as the leading alternative because it was the lowest cost viable alternative that addressed the reliability and safety risks. Alternative i was not selected because it does not meet current safety requirements and does not mitigate reliability risk of equipment and requires an

[1] Start Date of Construction is the Implementation Approval Date.

extended outage during construction. Alternative ii is not viable because there is insufficient physical space to install two new separate distribution transformers. Alternative iii and iv were not selected as both required the need to relocate 138 kV transmission lines and were more expensive without providing greater benefits compared to Alternative v.	
Project Impacts and Benefits: • Reduced environmental risk by installing oil containment for the new T1 and T2 transformers. • Improved reliability of the overall switchyard by replacement and reconfiguration of major equipment. • Reduced worker safety risk though improved access for operation and maintenance.	
Project Implementation Phase Risk: Due to the unknown soil conditions beneath existing T1 and T2, there is an increased likelihood of encountering contaminated soil which could delay the schedule and increase the cost for clean-up.	**Risk Treatment:** The treatment plan is to ensure project contingency includes additional disposal costs for contaminated soil and ensure that the schedule has sufficient float for additional excavation to remove the contaminated soil.
Additional Information: N/A	

Investment Planning ID: 93705	Project Name: Kidd1 – 60 kV Renovation, 4 kV Decommission & Control Room	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Identification	**Filing Reference:** F20-F21 RRA: • Chapter 6, page 6-111 • Appendix I, Transmission - line 32 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-32 • Appendix I, Transmission - line 27	

Description:

The purpose of the project is to upgrade the equipment to ensure safe and reliable operation at the Kidd1 Substation.

Key Drivers:

- Reliability
- Safety
- Environmental

Issues Being Addressed:

Originally built in 1951, the Kidd1 Substation is a transmission and 100 MVA distribution substation that supplies over 20,000 customers in the Vancouver South area. There are reliability risks with eleven of the twelve 60 kV circuit breakers, 4 kV transformers and much of the equipment in the feeder section that have an Asset Health Index rating of Poor and are nearing end-of-life. The end-of-life conditions are confirmed by repeated failure of the equipment, engineering analysis, lack of parts and support from the original equipment manufacturer, and the high cost of maintenance and repair. There are safety risks due to the probability of a catastrophic failure of the equipment.

In addition, the main control building is in very poor condition as it has a leaking roof, contains asbestos and is seismically deficient. Approximately 40 per cent of the Protection and Control relays and panels in the control building have an Asset Health Index rating of poor. Additionally, approximately 70 per cent of the Protection and Control relays are the older, mechanical type relays from the original installation, and are obsolete and no longer supported by the manufacturer.

Some equipment contains Polychlorinated Biphenyl (**PCB**) contaminated oil. Current Federal PCB Regulations require phase out of electrical equipment containing PCB levels of 50 ppm or more by 2025.

Discussion of Alternatives:

BC Hydro is considering four alternatives:

i. **Replace the 60 kV bulk oil circuit breakers with new dead tank breakers in the existing 60 kV lattice structure**;
ii. **Replace the 60 kV equipment in place and retrofit the existing 60 kV lattice structure and supporting foundations to resist seismic loads**;
iii. **Build a new compact structure 60 kV switchyard:** The new switchyard would be located in the old 4 kV switchyard which is being decommissioned. The foundation and the overlaying structures would

[1] Start Date of Construction is the Implementation Approval Date.

be designed to withstand earthquakes with the present BC Hydro standards; and iv. **Build a new low profile 60 kV switchyard:** The new switchyard to be located in the old 4 kV switchyard which is being decommissioned. The foundation and the overlaying structures would be designed to withstand the earthquakes with the present BC Hydro standards. All alternatives include replacing the 60 kV circuit breakers, decommissioning the 4 kV switchyard, and relocating the 60 kV control room onto the third floor of the Gas Insulated Switchgear building. The project has not yet completed an evaluation of the alternatives.
Project Impacts and Benefits: • Improved reliability from end-of-life equipment. • Removed safety risk from the catastrophic failure of end-of-life equipment. • Removed environmental risk from possible oil leaks from end-of-life equipment. • Removed equipment with PCB levels at or above 50 ppm by the December 31, 2025 Federal Regulation deadline.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase.	To be determined as the project reaches Implementation Phase.

Additional Information: N/A

<table>
<tr><td>Investment Planning ID:
901248</td><td colspan="2">Project Name:
Kimberley to Marysville Substation Relocation</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F22 RRA:
• Chapter 6, page 6-45
• Appendix I, Transmission - line 33</td></tr>
</table>

Description:

The purpose of this project is to replace the Kimberly (**KBY**) substation with an expansion of the Marysville (**MVL**) substation which will improve the safety and reliability of the substation to service the load of a key account industrial customer.

Key Drivers:

- Reliability
- Safety
- Environmental

Issues Being Addressed:

The KBY substation was built on leased land in 1968 and the structural poles, relays, switches, circuit breakers and controls have an Asset Health Index rating of Poor or Very Poor and are nearing their end-of-life. There is a risk of catastrophic failure (i.e., an explosion and fire) of the equipment that poses a safety hazard to workers. Additionally, the circuit breakers contain Polychlorinated Biphenyl contaminated oil that are a worker health hazard and a risk to the environment if it leaks from the end-of-life equipment. The new switchyard will be built on property owned by BC Hydro by expanding our existing MVL substation.

Discussion of Alternatives:

BC Hydro considered three alternatives:

i. **Do Nothing**;

ii. **Rebuild in place:** replaces the equipment in place but requires lease or procurement of adjacent land from the industrial customer; and

iii. **Rebuild in a new location at Marysville:** replaces the equipment on BC Hydro owned land adjacent to our existing MVL substation. No new lines are required.

Alternative iii, rebuild in a new location at Marysville is the Single Viable Alternative that addresses all of the project objectives and is more cost-effective than Alternative ii.

Alternative i does not address the risks at the KBY substation.

Alternative ii is a higher cost option with a longer schedule and compared to Alternative iii would require land lease or purchase from the industrial customer adjacent to KBY to execute the rebuild in place, would be difficult to perform some sustainment work at KBY, and has a risk of ground contamination at the site.

Project Impacts and Benefits:

- Improved reliability with new equipment having a 50-year service life.
- Removed safety risks by decommissioning the KBY substation.
- Removed environmental risks by decommissioning old equipment that could leak Polychlorinated Biphenyl.

Project Implementation Phase Risk: Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase.	Risk Treatment: To be determined as the project reaches Implementation Phase.
Additional Information: N/A	

<table>
<tr><td>Investment Planning ID:
93729</td><td colspan="2">Project Name:
Long Span Crossing Refurbishment - F17/F18 (1L37)</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• Chapter 6, page 6-117
• Appendix I, Transmission - line 67, Appendix K, page 76
• BCUC IR 1.133.1 Confidential
F22 RRA:
• Chapter 6, page 6-53
• Appendix I, Transmission - line 63</td></tr>
<tr><td colspan="3">Description:
The purpose of the project is to eliminate the safety hazard to the public and workers posed by the end-of-life conductor on the Jervis inlet and Agamemnon channel crossings and improve the thermal capacity of the circuit at these locations to match the other sections of the circuits.</td></tr>
<tr><td colspan="3">Key Drivers:
• Safety
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
1L37 was constructed in 1966/67 and runs from Malaspina to Saltery Bay, serves communities on the Sunshine Coast, and provides tie-ins for several Independent Power Producers in the area. There are two major water crossings, one over the Agamemnon Channel and a second across Jervis Inlet. The Jervis Inlet crossing spans approximately 3.1 km and is the longest overhead crossing in the BC Hydro system.
An inspection of the Jervis inlet and Agamemnon channel water crossings for the circuit was conducted in 2015. The inspection identified that both the Jervis Inlet and Agamemnon Channel crossings have become hazards due to corrosion of the conductor and are no longer feasible to safely operate regularly, and the conductor has been de-rated. The circuit is operational only in case of emergency with very limited load.
The condition of the parallel crossing of 2L48 will be addressed in a future project. As part of this project, the security of supply to the Powell River area is also being considered, including the transmission performance planning criteria for elements of the transmission system that could take longer than one year to repair. As part of the analysis, the ability to use a replacement 1L37 crossing as a backup crossing for 2L48 will be considered.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
BC Hydro is considering three alternatives:
i. Re-Conductor and Refurbish structures: Refurbish the existing structures and their foundations and install new conductor on the crossings on 1L37;
ii. Re-Conductor with new structures: Design and build new structures and foundations and install new conductor on the crossings on 1L37; and
iii. Removal of Crossing spans: Remove the conductor from the crossing spans and remove the associated structures which will return the Powell River area to service by a single radial line.
The project is currently evaluating the alternatives.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits:	
• Address the safety risk by removing the end-of-life conductor on the Jervis inlet and Agamemnon channel crossings.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase.	**Risk Treatment:** To be determined as the project reaches Implementation Phase.
Additional Information: N/A	

<table>
<tr><td colspan="1">Investment Planning ID:
900992</td><td colspan="2">Project Name:
Lower Mainland – Capacitive and Reactive Power Reinforcement</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:

F20-F21 RRA:
• Chapter 6, page 6-103
• Appendix I, Transmission - line 10, Appendix J, page 84, Appendix K, page 58
• Appendix H, page 14
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1

F22 RRA:
• Chapter 6, page 6-31 and 6-39
• Appendix E, page 13
• Appendix I, Transmission - line 9
• BCUC IR 1.45.2</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to supply sufficient reactive power compensation in the Lower Mainland transmission system to provide voltage support and control to the Lower Mainland transmission system, and to address the Fraser Valley voltage stability constraints.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The four Burrard Synchronous Condenser units are reaching end-of-life, and the Equipment Health Rating of the equipment is either Poor or Unsatisfactory. The units are expected to experience reliability issues within the short to medium term. Each of the four units is rated as -50 Mega Volt Amps reactive (MVAr) / +100 MVAr and provide capacitive and reactive power to the Lower Mainland transmission system, which allows voltage control and prevents voltage instability during peak load periods.
In addition, the 2016 transmission planning Mandatory Reliability Standard assessment of the Fraser Valley transmission system identified voltage stability constraints caused by additional reactive power losses within the 10-year planning horizon that will need to be reinforced. The voltage instability would result in voltage collapse and subsequent load loss in the Fraser Valley.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives:

BC Hydro is considering three alternatives:

i. **Install 230 kV Shunt Capacitor and Shunt Reactor Compensation:** A total of 750 MVAr of capacitive power compensation and a total of 200 MVAr of shunt reactive power compensation would be installed in the Lower Mainland at 230 kV;

ii. **Install 500 kV and 230 kV Shunt Capacitor and Shunt Reactor Compensation:** A total of 750 MVAr of capacitive power compensation would be installed in the Lower Mainland: 250 MVAr at 500 kV, and 500 MVAr at 230 kV. A total of 200 MVAr shunt reactive power compensation would be installed in the Lower Mainland at 230 kV; and

iii. **Restore Burrard Synchronous Condenser Capability and Install Shunt Capacitor Compensation:** Burrard Synchronous Condenser reactive power function would be restored and 500 MVAr of capacitive power compensation would be installed in the Fraser Valley at 230 kV.

The project has not yet completed an evaluation of the alternatives.

Project Impacts and Benefits:

- Maintain BC Hydro's Lower Mainland bulk transmission system reliability during heavy winter load periods under single contingency conditions.
- Reduce the likelihood of cascading outages to the rest of the Western Electricity Coordinating Council regional system.
- Secure regional Fraser Valley transmission system reliability by compensating for Volt Amp reactive (VAr) losses during heavy winter load periods under single contingency conditions.

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase.	To be determined as the project reaches Implementation Phase.

Additional Information:

N/A

<table>
<tr><td>Investment Planning ID:
92478</td><td colspan="2">Project Name:
Mainwaring Station Upgrade</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
2014 Annual Report to the BCUC:
• Appendix I, line 15;
• Appendix J, page 57.
F17-F19 RRA:
• Appendix I, line 43, Appendix J, page 69
• BCUC IRs 1.70.3, 1.110.5, 2.249.8, 2.253.2, 2.254.1.1, 2.260.4, 2.267.2, BCOAPO IR 1.36.1, CEC IR 1.78.1
• CPCN: To be filed as requested by BCUC
F20-F21 RRA:
• Chapter 6, page 6-111
• Appendix G, page 32
• Appendix I, Transmission - line 33, Appendix J, page 103, Appendix K, page 51 and page 59
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
• Exhibit B-54, BC Hydro Undertaking No. 50
F22 RRA:
• Chapter 6, page 6-45
• Appendix E, page 14
• Appendix I, Transmission - line 28
• Appendix P, page 28
• BCUC IR 1.45.2</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to improve the reliability, safety and environmental risks at the Mainwaring (MAN) substation.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Safety
• Environmental</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Issues Being Addressed: The MAN substation transformers T1 and T3 have been in service for 60 years, and are nearing their end-of-life, resulting in increasing reliability and safety risks. T3 has an Asset Health Index rating of Poor. T1 has an Asset Health Index rating of Satisfactory but must be regularly maintained as it is leaking oil. Both transformers have no on-load tap changers resulting in the need for 40 voltage regulators on the feeder positions. The voltage regulators also have an Asset Health Index rating of Poor. The majority of the feeder sections have an Asset Health Index rating of Poor, and are nearing their end-of-life, resulting in increasing reliability risks. The existing feeder section also has clearance issues that poses a safety risk for workers. Many of the circuit breakers and voltage regulators contain Polychlorinated Biphenyl (**PCB**) contaminated oil. Current Federal PCB Regulations require the phase out of electrical equipment containing PCB levels of 50 ppm or more by 2025.	
Discussion of Alternatives: For the power transformers T1 and T3 portion of the scope, replacing the transformers with new units was selected as the preferred alternative as this was the only alternative that met the project objectives of addressing the reliability risk of the aging equipment. For the 50/60 Series Feeder Section portion of the scope, BC Hydro considered three alternatives: i. **Refurbish** the existing 50/60 series feeder section; ii. **Replace** the existing 50/60 series feeder section with a new indoor Gas Insulated (**GIS**) feeder section; and iii. **Replace part of** the existing 50/60 series feeder section with a new GIS feeder section, refurbish the remainder. Alternate ii, Replace the existing 50/60 series feeder section with a new indoor GIS feeder section, was selected as the preferred alternative because it would eliminate the existing safety hazards and seismic risks and would include provisions to add seven more feeders to serve future growth, for a reasonable cost relative to the other viable alternatives.	
Project Impacts and Benefits: • Improve reliability of the aging equipment. • Reduce worker safety risks by extending and upgrading the substation. • Removed equipment with PCB levels at or above 50 ppm by the December 31, 2025 Federal Regulation deadline.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase.	**Risk Treatment:** To be determined as the project reaches Implementation Phase.
Additional Information: Although the project forecasts a cost to be less than $100 million (Capital Filing Guidelines application expenditure threshold for Power System projects), in Directive 3 of the BCUC's Decision on the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, the BCUC stated that the Mainwaring Substation Upgrade project could have potentially significant public interest issues and directed BC Hydro to file a CPCN.	

Investment Planning ID: 901613	Project Name: Maple Ridge - Feeder Section 60 Series Refurbishment	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** F22 RRA: • Chapter 6, page 6-45 • Appendix I, Transmission - line 34	

Description:

This project will address reliability risks associated with the end-of-life equipment of the Maple Ridge (**MRG**) substation, as well as inadequate feeder section electrical clearances and seismic risks.

Key Drivers:

- Reliability
- Safety

Issues Being Addressed:

The MRG substation is a 69/25 kV distribution station serving the City of Maple Ridge. This station supplies approximately 70 MVA of load. The MRG substation feeder section (60 Series) was originally built in the 1950s at 12 kV and later upgraded in the 1970s to 25 kV. As a result, the electrical clearance to ground is less than typical for a 25 kV feeder section and does not meet the current engineering standards. The concrete block retaining wall that supports the feeder section and the lattice-type steel structure in the feeder section were not designed to withstand a major seismic event. The electro-mechanical Protection and Control relays are obsolete and there is not adequate space in the building to carry out any Protection and Control equipment upgrades. The condition of oil circuit breakers and disconnect switches on the feeder section 60 series have reached end of life. The original equipment manufacturers have discontinued parts and technical support. One of the bulk oil circuit breakers needs to be removed due to its polychlorinated biphenyl content by 2025 to meet the federal regulation.

Discussion of Alternatives:

BC Hydro is considering two alternatives:

i. **Replace the feeder section with a GIS feeder section with control room in the same building:** This alternative will replace the feeder section, replace the end-of-life assets and remove the seismic risk of the concrete retaining wall; and

ii. **Do nothing:** this alternative does not address the issues identified above.

Project Impacts and Benefits:

- Maintain reliability in the area served by the MRG substation.
- Address safety concerns at the MRG substation.
- Address seismic concerns at the MRG substation.

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

N/A

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: 92907	Project Name: Mount Lehman Substation Upgrade	
Forecast Capital Cost: $59.1 million	**Forecast In-Service Date:** Fiscal 2023	**Start Date of Construction:**[1] Fiscal 2020
Development Phase: Implementation	**Filing Reference:** F2014 Annual Report to the BCUC: • Appendix I, line 116; • Appendix J, page 61. F17-F19 RRA: • Appendix I, line 33, Appendix J, page 61, • BCUC IRs 1.70.3, 2.249.8, 2.254.1.1, 2.260.4, BCOAPO IR 1.36.1 F20-F21 RRA: • Chapter 6, page 6-104 • Appendix H, page 14 • Appendix I, Transmission - line 13, Appendix J, page 89, Appendix K, page 46 and page 51 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 • CEC IR 3.104.1 and 4.22.1 F22 RRA: • Chapter 6, page 6-34 and 6-40 • Appendix E, page 14 • Appendix I, Transmission - line 12 • Appendix Q, page 23	

Description:

The purpose of this project is to upgrade the Mount Lehman (**MLE**) substation to increase the capacity from 100 MVA to 150 MVA, which serves the load in the Abbotsford area and enables decommissioning of the Sumas Way (**SMW**) substation.

Key Drivers:

- Reliability
- Safety

Issues Being Addressed:

The Abbotsford area is currently supplied by the MLE, Clayburn (**CBN**), Gloucester, and SMW substations. At present, the total capacity of these four stations is 360 MVA. The general strategy for the area is to upgrade the MLE substation, upgrade and address safety issues at the CBN substation, and after the capacity upgrades, decommission the SMW substation.

MLE is a 230/25 kV substation and was placed in service in 2007, with a total transformation capacity of 100 MVA. Upgrading the MLE substation to 150 MVA is required to enable decommissioning of the SMW substation. SMW substation has increased reliability risks due to degrading asset condition and has elevated safety risks due to the non-arc resistant metalclad design of the 25 kV feeder section. The expansion of MLE substation will also enable safety improvements to be undertaken at CBN substation

[1] Start Date of Construction is the Implementation Approval Date.

and ensure that load in the Abbotsford area continues to be served over time.
Discussion of Alternatives: This project was identified as a result of a 30-year study carried out for the Abbotsford area in 2013 to mitigate safety issues at SMW and CBN substations and address capacity shortage in the Abbotsford area. The area study resulted in three alternative solutions being identified and reviewed. The alternative comparison was a comparison of different implementation strategies to determine not only what should be done, but also their timing. BC Hydro considered three sets of alternatives: i. Expand MLE in the First Phase' Reinforce CBN in the Near Term and Expand in the Future; and Decommission SMW in the Near Term. ii. Expand MLE in the Future; Reinforce CBN in the Near Term and Expand in the Future; and Expand SMW in the First Phase and Replace Metalclad in the Near Term. iii. Expand MLE in the Future; Expand CBN in the Near Term; and Decommission SMW in the Near Term. Alternative i was accepted as the overall strategy as it was technically superior to Alternative iii, and more cost effective that Alternative ii. The strategy includes four projects over three phases. The MLE Substation upgrade to 150 MVA in the first phase will address the issues and meet the objectives of the overall Abbotsford area strategy. The MLE Substation upgrade is less expensive than the other alternatives, provides sufficient capacity to supply the area's needs for 6 years longer than the other alternatives, has the lowest transmission reinforcement costs and system losses, and facilitates the important migration of load from the constrained Fraser Valley 60kV systems to the more robust Fraser Valley 230 kV systems. First Phase: i. MLE Substation upgrade to 150 MVA (this project); Second Phase: ii. CBN Substation upgrade to 200 MVA; iii. SMW Substation decommissioning; and Third Phase: iv. CBN Substation upgrade to 300 MVA. This project is the MLE Substation Upgrade (first phase) and is the only alternative to deliver the overall Abbotsford area strategy, as discussed in Alternative i above.
Project Impacts and Benefits: • Increase capacity in the Abbotsford area to ensure that BC Hydro can continue to reliably meet the needs of existing and future customers for at least the next 10 years. • Enable safety improvements and a capacity increase at CBN substation. • Increasing the capacity of MLE and CBN to service the Abbotsford area will facilitate the decommissioning of the SMW substation as this is the most cost-effective way to address the safety risks at this substation.

Project Implementation Phase Risk:	**Risk Treatment:**
Schedule delay risk if an outage is not available when needed for completion of construction.	There is float in the schedule and dialogue is ongoing with Fraser Valley Operations to confirm the outage date.

Additional Information: N/A

<table>
<tr><td>Investment Planning ID:
900152</td><td colspan="2">Project Name:
Natal Sub – NTL 60 138 kV Rebuild</td></tr>
<tr><td>Forecast Capital Cost:
$139.2 million to $46.8 million</td><td>Forecast In-Service Date:
Fiscal 2025</td><td>Start Date of Construction:[1]
Fiscal 2022</td></tr>
<tr><td>Development Phase:
Definition</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• Chapter 6, page 6-111
• Appendix H, page 14
• Appendix I, Transmission - line 34, Appendix J, page 105, Appendix K, page 51 and 62
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-45
• Appendix I, Transmission - line 29</td></tr>
<tr><td colspan="3">Description:
The purpose of the project is to improve the reliability and reduce environmental risks at the Natal (NTL) substation.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Environmental</td></tr>
<tr><td colspan="3">Issues Being Addressed:
Originally built in 1946, NTL substation is a transmission substation in southeast B.C. region and is a point of intertie with the Alberta transmission system. NTL substation is also connected to several other BC Hydro substations at 60 kV, 138 kV, and 230 kV as well as multiple transmission voltage customers.
The NTL substation has reliability risks with the power transformers, voltage regulators, circuit breakers, disconnect switches, instrument transformers, control building and many protection relays in the 60 kV to 138 kV switchyard as they have an Asset Health Index of either Poor or Very Poor.
Two circuit breakers contain Polychlorinated Biphenyl (PCB) contaminated oil. Current Federal PCB Regulations require the phase out of electrical equipment containing PCB levels of 50 ppm or more by 2025.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
BC Hydro considered four alternatives:
i. Within the existing site, replace the NTL 60 kV to 138 kV switchyard, end of life equipment, and the control building;
ii. On a new property, replace the NTL 60 kV to 138 kV switchyard, end of life equipment, and the control building;
iii. Replace the NTL 60 kV to 138 kV switchyard considering 138 kV to 230 kV transformation and new, smaller 60 kV switchyard; and
iv. Do nothing or deferral.
Alternative i, within the existing site, replace the NTL substation 60 kV to 138 kV switchyard, end of life equipment, and the control building, was selected as the preferred alternative. This alternative will</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">address the current health and condition of the existing 60 kV to 138 kV station, which poses unacceptable reliability risks. This alternative maintains power supply to customers during the construction period. Alternative ii was rejected because there is already sufficient property available at Natal to rebuild the substation and because acquiring a new property would add extra cost and project schedule delays to meet the PCB removal timeline requirements. Alternative iii was not considered further due to significant additional costs; in addition to replacing the 60-138 kV switchyard, this alternative would also require a station reconfiguration, including an upgrade of the 230 kV switchyard to include multiple breakers, new 230-138 kV transformers and associated protection and controls. Alternative iv was rejected because it does not address the reliability risks posed by the age and condition of the equipment, safety issues, or the PCB removal requirement.</td></tr>
<tr><td colspan="2">Project Impacts and Benefits:
• Improved reliability of the end-of-life equipment.
• Removed equipment with PCB levels at or above 50 ppm by the December 31, 2025 Federal Regulation deadline.</td></tr>
<tr><td>Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase.</td><td>Risk Treatment:
To be determined as the project reaches Implementation Phase.</td></tr>
<tr><td colspan="2">Additional Information:
N/A</td></tr>
</table>

<table>
<tr><td>Investment Planning ID:
900625</td><td colspan="2">Project Name:
NERC CIP V5 Compliance at Medium Impact Transmission Stations</td></tr>
<tr><td>Forecast Capital Cost:[1]
$35.5 million</td><td>Forecast In-Service Date:[2]
Fiscal 2027</td><td>Start Date of Construction:
Fiscal 2017</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I, line 47, Appendix J, page 73,
• BCUC IRs 1.70.3, 1.111.1 to 1.111.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1
F20-F21 RRA:
• Chapter 6, page 6-112
• Appendix I, Transmission - line 41, Appendix J, page 109, Appendix K, page 79
• BCUC IRs 1.133.1 Confidential and 1.123.12
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-47
• Appendix I, Transmission - line 38
• RCIG IR 1.8.6</td></tr>
<tr><td colspan="3">Description:
This project included a number of scope items to achieve compliance with version 5 of the Critical Infrastructure Protection (CIP) Mandatory Reliability Standard (MRS) for Medium Impact Transmission Stations. BC Hydro achieved compliance with version 5 of the CIP MRS for Medium Impact Transmission Stations on October 1, 2018.
This project also included implementing a system to implement a Station Gateway System to automate a number of manual compliance processes to aid with sustainment activities. In July 2021, BC Hydro decided to eliminate the Station Gateway System scope from this project, and plan for a future project to re-plan and implement an improved version of the Station Gateway Software that improves reliability, usability, and performance.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Reputational
• Financial Loss</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The purpose of the project is to upgrade electronic and physical security for computer/electronic equipment used to control and monitor the Bulk Electric System to meet the compliance requirements of version 5 of the CIP MRS.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
N/A</td></tr>
</table>

1 Forecast Capital Cost was $40.1 million at December 31, 2018.
2 The new expected In-Service Date is fiscal 2022 based on the scope change described in the Description section.

Project Impacts and Benefits: • Meet compliance requirements of version 5 of the CIP MRS. • Improve overall cyber security of Bulk Electric System Cyber Assets. • Mitigate risk of financial penalties for non-compliance.	
Project Implementation Phase Risk: The ongoing Transmission Stations element currently does not have any identified Zone 3 (high) Implementation Phase risks.	**Risk Treatment:** N/A
Additional Information: N/A	

Investment Planning ID: 92479	Project Name: Newell Substation Upgrade	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Identification	**Filing Reference:** F20-F21 RRA: • Chapter 6, page 6-111 • Appendix I, Transmission - line 35, Appendix K, page 51 and 61 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: Under $5M Project Estimate	

Description:

The purpose of this project is to improve the safety, environmental and reliability issues at Newell substation.

Key Drivers:

- Reliability
- Safety
- Environmental

Issues Being Addressed:

The Newell Substation has reliability risks with the transformer T1 and some equipment in the 50/60 series feeder section that were installed in the 1950s, have an Asset Health Index rating or Poor or Very Poor, and are nearing end-of-life. The lattice type steel structure of the feeder section was also built in the 1950s and it was not designed to withstand a major seismic event.

There are also safety risks due to insufficient electrical clearances in the feeder section. The feeder section was built for 4 kV in the 1950s and bus to finished grade electrical clearances do not meet the current engineering standards. In the feeder section, the bulk oil circuit breakers are the same type that have failed catastrophically in recent years in some other substations.

There are environmental risks due to polychlorinated biphenyls, which are below 43 ppm, in the bulk oil circuit breakers. End-of-life oil-filled equipment has high risks of oil leak due to deterioration of the seals.

Discussion of Alternatives:

BC Hydro is considering two alternatives:

i. **Replace Feeder Section 50/60 Series and Remove Transformer T1**: This involves transferring 14 existing feeders to a new Gas Insulated Switchgear feeder section, retrofitting 4 existing feeder positions and removing transformer T1 and associated protection and control equipment; and

ii. **Retrofit 50/60 Feeder Section and Remove Transformer T1**: This involves retrofitting the equipment by replacing end-of-life components of the equipment, and similar to Alternative i, removing transformer T1 and associated protection and control equipment.

The preferred alternative has not yet been determined.

Project Impacts and Benefits:

- Reduce reliability, environmental and safety risks by extending and upgrading the substation.

1 Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase.	To be determined as the project reaches Implementation Phase.
Additional Information: N/A	

Investment Planning ID: 901572	Project Name: North Montney Region - Electrification	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Identification	**Filing Reference:** F22 RRA: • Chapter 6, page 6-36 • Appendix I: Transmission - line 4 • BCUC IRs 1.45.2, 1.43.1 • BCOAPO IRs 1.56.1	

Description:

The purpose of this project is to expand BC Hydro's transmission system into the North Montney region of northeastern B.C. to provide transmission service to industrial operations to reduce greenhouse gases emissions. The absence of transmission infrastructure in this region is a barrier to electrification of current and future industry.

Key Drivers:

- Environmental
- Reliability

Issues Being Addressed:

The North Montney Natural Gas Field, located northeast of BC Hydro's GM Shrum Generating Station, is one of the sources for natural gas for LNG Canada and other proposed liquified natural gas facilities. The upstream gas producers are developing several gas plants and an opportunity exists to have these gas plants use electric drive compressors instead of natural gas drive compressors.

A number of gas producers in the area have expressed interest in grid supply service from BC Hydro. The costs of interconnecting to BC Hydro's grid can be a significant barrier for gas producers not located close to major transmission lines. The lack of transmission infrastructure in this region is one impediment to these potential customers connecting to and taking service from BC Hydro because it is uneconomic for any single customer or group of customers to build a transmission extension to this area. A transmission expansion into this area would reduce the cost of electrifying the operations for these upstream gas producers to a point where a significant number of gas processing facilities (200-300 MW) could choose to use grid power.

A joint Memorandum of Understanding released by the federal and provincial governments on August 29, 2019 announced an opportunity to access Government of Canada funding and explore Indigenous ownership. The Memorandum of Understanding included the formation of a Canada-British Columbia Clean Power Planning Committee, with senior representation from both jurisdictions, including BC Hydro, to advance natural gas and liquified natural gas electrification, and specifically mentions the North Montney Region – Electrification project.

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">Discussion of Alternatives:
Two alternatives are being considered:
i. Construct a transmission line between GM Shrum Generating Station and a new substation in the vicinity of the Wonowon community; and
ii. Construct a transmission line between South Bank Substation and a new substation in the vicinity of the Wonowon community.
The project is currently in Conceptual Design Stage, and investigations are underway to assess the two alternatives.</td></tr>
<tr><td colspan="2">Project Impacts and Benefits:
• Contribute to the Government of B.C.'s CleanBC program goal of increasing access to clean electricity for large operations to reduce greenhouse gas emissions.
• Facilitate interconnection to provide clean electricity to planned natural gas productions.</td></tr>
<tr><td>Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase.</td><td>Risk Treatment:
To be determined as the project reaches Implementation Phase.</td></tr>
<tr><td colspan="2">Additional Information:
BC Hydro launched an expression of interest process in 2021 to assess the interest in electrification and the electrification needs of existing and planned industrial operations in the North Montney region. Based on the responses, BC Hydro is considering whether to move forward to the next stage of project development.</td></tr>
</table>

Investment Planning ID: 92759	Project Name: Patricia – Substation Upgrade	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Identification	**Filing Reference:** F20-F21 RRA: • Chapter 6, page 6-111 • Appendix I: Transmission - line 39, Appendix K: pages 51 and 65 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-45 • Appendix I: Transmission - line 36	

Description:

The purpose of the Patricia (**PCA**) Substation Upgrade project is to address reliability, safety and environmental risks associated with the end-of-life condition of the substation assets.

Key Drivers:

- Reliability
- Safety
- Environmental

Issues Being Addressed:

The most significant issues and risks associated with the PCA Substation include:

- Thirteen 12 kV bulk oil circuit breakers are in poor condition and contain Polychlorinated Biphenyl (**PCB**) levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline;
- The three power transformers were manufactured in the 1960s and do not have on-load tap changers, and therefore voltage regulators are required to regulate the voltage. The asset health of one of the power transformers is Poor;
- All 12 kV voltage regulators are in poor condition; and
- The 12 kV feeder section was designed to be compact in size and poses safety risks for workers due to limited clearance between energized equipment and ground. This risk is currently partially mitigated through physical barriers and warning signs.

Discussion of Alternatives:

BC Hydro considered several alternatives prior to the start of the project through the Prince George Area Study. The planning study looked at six alternatives to address capacity, asset health and reliability of the system servicing Prince George:

i. Upgrade all PCA Substation feeders to 25 kV, and then offload them to Foothills (**FHS**) and Chief Lake (**CHF**) substations until both substations reach firm capacity. Upgrade Pineview (**PVW**) substation to increase substation firm capacity;

ii. Upgrade all PCA Substation feeders to 25 kV then offload them to FHS Substation until it reaches its substation firm capacity. Then upgrade Beaverly substation to increase substation firm capacity;

iii. Upgrade all PCA feeders to 25 kV then offload them to FHS Substation. Upgrade FHS and PVW

[1] Start Date of Construction is the Implementation Approval Date.

Substations to increase substation firm capacity; iv. Decommission seven PCA Substation feeders. Upgrade 13 PCA Substation feeders to 25 kV then offload them to FHS, Chief Lake and Beaverly substations until these substations reach firm capacity; **v.** Build a new 25 kV substation adjacent to the existing PCA Substation. Upgrade PVW Substation to increase substation firm capacity; and vi. Rebuild PCA Substation at 12 kV. Alternative vi, Rebuild PCA Substation at 12 kV, was selected as the Single Viable Alternative during the Identification phase as this was the only alternative that would meet the project objectives and the regulatory deadline for PCB removal. In addition, the other alternatives would require significant capital investments that are not justified given there is no significant load growth forecast in the area and the PCA 12 kV feeder continues to perform reliably. The progression of design identified outage staging and construction complexities associated with the brownfield site. This has caused significant increases to cost and schedule. Based on these changes, the project alternatives will be re-assessed.
Project Impacts and Benefits: • Maintain reliability in the area served by PCA substation. • Address safety concerns at PCA substation. • Remove equipment with PCB levels at or above 50 ppm by the December 31, 2025 Federal PCB Regulation deadline. This work may move forward as a separate project as the alternatives are re-assessed.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase.	To be determined as the project reaches Implementation Phase.

Additional Information:
N/A

Investment Planning ID: 901821	Project Name: Peace to Kelly Lake - Stations Sustainment	
Forecast Capital Cost: $299 million to $172 million	**Forecast In-Service Date:** Fiscal 2027	**Start Date of Construction:**[1] Fiscal 2023
Development Phase: Definition	**Filing Reference:** New	

Description:

The purpose of this project is to address aging assets on the Peace Region to Kelly Lake 500 kV transmission system to improve the reliability of the system.

Key Drivers:

- Reliability

Issues Being Addressed:

The Peace to Kelly Lake 500 kV transmission system is the critical backbone infrastructure for moving power generated in the Peace Region to the province's load centre in the south. There are three 500 kV transmission lines that run from Gordon M. Shrum / Peace Canyon to Williston (**WSN**) substation and three lines that run from WSN substation to Kelly Lake substation. There are a number of assets along this corridor that have reached end-of-life that must be addressed to maintain this critical function.

The control systems for the 5CX2/3 series capacitor at Kennedy Capacitor Station (**KDY**) and 5CX3 series capacitor at McLeese Capacitor Station have reached end-of-life and their asset health is rated as Poor. There is a high risk of failure of these control systems. Failure of the control systems would reduce the transfer capability of the bulk transmission system by approximately 50 per cent. Because this equipment is obsolete, there is a lack of spares and original equipment manufacturer support. This has resulted in long outages and reduced system availability.

Shunt reactors 5RX1 at Peace Canyon Generating Station and 5RX6 at WSN substation are approaching end-of-life and their asset health is Poor. If these reactors fail, the system would experience high voltages when the 500 kV lines are under light load conditions; as a result, the lines may need to be taken out of service thus reducing the availability of the system.

The 500 kV control buildings at KDY and WSN substations are over 50 years old and have reached end-of-life and are not fit for future use. The diesel generator room is next to the control buildings, which is a safety concern and fire risk. The heating, ventilation, and air conditioning system, battery room and size of the existing control rooms are inadequate, and the control buildings contain hazardous materials such as asbestos.

Discussion of Alternatives:

The project spans many locations and asset types. The following alternatives were identified to address each of the aging assets: Control systems, 500 kV Shunt Reactors, KDY substation 500 kV Control Building and WSN substation 500 kV Control Building:

i. **Replace the aging asset**;

ii. **Repair or refurbish the aging asset**; and

iii. **Do nothing**.

For the WSN substation control building, Alternative i was selected, due to less risk with building a new control building compared to repairing the existing asset in the following areas: unforeseen costs, reliability of the system during and after construction, and worker safety during and after construction.

For the other assets Alternative i, replace the aging asset, is the only viable alternative. For the control systems, the only viable alternative is to replace the control systems because the parts required to complete the repairs and for ongoing maintenance are no longer available. For the shunt reactors, the only viable alternative is to replace the reactors because the old components are not readily available and

[1] Start Date of Construction is the Implementation Approval Date.

significant engineering and design effort would be required to make these components compatible with other new equipment being installed at WSN substation. For the KDY substation control building, the only viable alternative is to replace the control building because there are significant construction challenges and risks with refurbishing the control building. For each asset, the Do Nothing alternative was not considered a viable option as it does not address the issue of reliability due to the aging condition of these critical system assets.
Project Impacts and Benefits: • Improve reliability through reinforcement of the transmission corridor between the Peace Region and Kelly Lake substation so power from generation in the Peace Region can be moved south.

Project Implementation Phase Risk:	**Risk Treatment:**
This project is not yet in Implementation.	N/A

Additional Information: In fiscal 2020, BC Hydro cancelled the Peace to Kelly Lake Capacitors Project (**PKCP**). The PKCP contemplated both the work required to increase the transfer capability and the sustaining work. With the cancellation of PKCP, the sustaining work still needed to be completed in a timely manner to ensure the continued reliability of the existing Peace to Kelly Lake 500 kV transmission system. To leverage activities completed as part of PKCP, BC Hydro bundled the sustaining work into a new project and named it the Peace to Kelly Lake Stations Sustainment Project. A section 44.2 application will be filed with the BCUC in fall 2021.

<table>
<tr><td colspan="3">Project Name: Peace to Kelly Lake – Reactor Replacement</td></tr>
<tr><td colspan="3"></td></tr>
<tr><td colspan="3">Appendix I Reference:
Transmission, page X, lines A, B, C</td></tr>
<tr><td>Investment Planning ID:
900185 (Phase 2)
900186 (Phase 3)
900187 (Phase 4)</td><td colspan="2">Project Name:
Peace to Kelly Lake – Reactor Replacement (Phase 2)
Peace to Kelly Lake – Reactor Replacement (Phase 3)
Peace to Kelly Lake – Reactor Replacement (Phase 4)</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In -Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Identification (Phase 2)
Future (Phases 3 and 4)</td><td colspan="2">Filing Reference:
F20-F21 RRA (900185):
• Chapter 6, page 6-111
• Appendix I, Transmission - line 40, Appendix J, page 107
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA (900185):
• Chapter 6, page 6-45
• Appendix I, Transmission - line 37</td></tr>
<tr><td colspan="3"></td></tr>
<tr><td colspan="3">Description of Program of Projects:
The Peace to Kelly Lake transmission line reactors are required for the operation of the 500 kV bulk transmission system from the Peace Generation system. Failure of any one of the reactors may result in unacceptable high voltage in the 500 kV system and affect the continued operation of the 500 kV system.
This Program of Projects was defined to replace aging 500 kV shunt reactors associated with the Peace Region to Kelly Lake transmission system. The majority of these reactors were installed in the late 1960s, are leaking oil and have seismically vulnerable bushings. Refurbishing to correct the issues is costly and generally has little impact on extending the life of the equipment.
The replacements will be completed via the following phased approach:
• Phase 1 - G.M. Shrum 5RX1, 5RX2. This project is in Implementation phase with an in-service date of fiscal 2022;
• Phase 2 - Kelly Lake 5RX1, 5RX3;
• Phase 3 - Williston 5RX2, 5RX3, 5RX4; and
• Phase 4 - Williston 5RX5, 5RX7.
A Program Delivery Strategy was developed during Phase 1's Identification Phase. This delivery strategy included:
• A blanket contract order for 500 kV shunt reactors; and
• A blanket construction contract which included unit pricing for shunt reactors.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Issues to be addressed:

The Peace to Kelly Lake transmission lines are the only means of delivering the power generated in the Peace Region to load centers in the southern portion of the province. These load centers include the Lower Mainland and Vancouver Island, which comprise approximately two-thirds of the BC Hydro's load. The net generation in the Peace Region, including heritage generating stations such as Gordon M. Shrum (**GMS**) and Peace Canyon (**PCN**), and independent power producers, is approximately 4,360 MW, or approximately 23 per cent of the total provincial generation capacity.

The Peace to Kelly Lake transmission line reactors have an Asset Health Rating of Poor indicating an increased likelihood of failure. Each will be replaced with a new reactor with an expected life of about 40 years. Their replacement will reduce the risk of forced outages and risk to workers within the substations.

Schedule of Program of Projects:

The program strategy was initiated to replace the reactors over an approximate 10-year period.

Risks and Mitigation Strategies:

Each project phase will:

- Identify project risks starting in Identification Phase and finalized in the Implementation Phase; and
- Identify risk mitigation strategies when the project reaches Definition phase.

Additional Information:

N/A

<table>
<tr><td>Investment Planning ID:
901040</td><td colspan="2">Project Name:
Port Alberni - Substation Refurbishment</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Future</td><td colspan="2">Filing Reference:
F22 RRA:
• Chapter 6, page 6-48
• Appendix I, Transmission - line 48</td></tr>
</table>

Description:

This project will address reliability risks associated with the end-of-life equipment of the Port Alberni (**PAL**) substation, as well as seismic and tsunami risks.

Key Drivers:

- Reliability
- Safety

Issues Being Addressed:

PAL substation is in Port Alberni on Vancouver Island. The station provides power to Port Alberni customers and the Catalyst Paper pulp and paper mill.

The control building at PAL was built in 1956. It is a brick building past end of life, was not built to seismic standards, and is in a high risk seismic and tsunami area. Asbestos is present in various components. The control building does not meet current building code or BC Hydro design standards.

Additional assets that are at end of life include:

- Six 138 kV bulk oil circuit breakers installed in 1982;
- Four SF6 breakers installed in 1983 with the current transformers;
- Five 12 kV bulk oil circuit breakers and six 25 kV bulk oil circuit breakers; and
- Oil filled current transformers, voltage transformers and others for protection functions.

Discussion of Alternatives:

BC Hydro is considering three alternatives:

i. **Build a new station and decommission existing PAL station:** This alternative will build a new station at a new site and decommission the existing substation. This alternative would address the end of life equipment, tsunami and seismic risk;

ii. **Rebuild the station at the existing site:** This alternative will rebuild the station at the existing site and replace the end of life assets. This alternative would address the end of life equipment but retain tsunami and seismic risk; and

iii. **Do nothing:** this alternative would not address the issues identified above.

Project Impacts and Benefits:

- Maintain reliability in the area served by PAL station.
- Address seismic and tsunami concerns at PAL station.
- Address safety concerns at PAL station.

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.
Additional Information: N/A	

Investment Planning ID: 901574	Project Name: Prince George to Terrace Capacitors Project	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:** To be determined
Development Phase: Identification	**Filing Reference:** F20-F21 RRA: • BCUC IRs 1.254.2.1 and 2.247.6.1 F22 RRA: • BCOAPO IR 1.56.1	

Description:

The purpose of this project is to increase capacity of the North Coast 500 kV transmission system by at least 500 MW to meet the needs of interconnection customers currently in the interconnection queue and support the provincial government's initiatives under CleanBC.

This project has secured federal funding up to a maximum of $97 million from the Green Infrastructure stream of the Investing in Canada Infrastructure Program, in recognition of the greenhouse gas reductions to be achieved.

Key Drivers:

- Operational Requirements
- Environmental

Issues Being Addressed:

There are a number of customers who are requesting interconnections in the North Coast. BC Hydro's existing north coast 500 kV transmission system transfer capacity is insufficient to supply all the customers who are currently requesting interconnections. To meet the needs of interconnection customers and their requested in-service dates, additional system capacity will be required by fall 2026.

Discussion of Alternatives:

BC Hydro considered five alternatives:

i. **Do Nothing:** This alternative would not increase the electricity supply in the north coast area and BC Hydro would fail to meet its obligation to provide service to customers who request it per the Tariff;

ii. **Deferral:** Due to the long lead time for the Project, a deferral would increase the risk that the required incremental supply of electricity would not be in place to meet the needs of customers. As a result, the customers would be less likely to electrify their load;

iii. **Construct second 500 kV transmission line** – A second new, 450 km transmission line parallel to the existing line was anticipated to be approximately $1.9 billion. Although this alternative would provide a N-1 level of reliability, the customer has indicated that a N-0 level of reliability is sufficient to meet their needs;

iv. **Local generation with dependable capacity** – Gas turbine generators are the only potential local generation with dependable capacity in the region and they do not meet the project's objective of supporting the BC Government in achieving its climate goals; and

v. **Install series compensation on the existing 500 kV line** – construct three new capacitor stations along transmission lines 5L61, 5L62 and 5L63 and install a third transformer at Skeena substation.

Alternative v, install series compensation on existing 500 kV line, was selected as the Single Viable Alternative for the following reasons: (1) it is the only alternative that meets the project objective to provide service to the interconnection customers in the required timeframe; (2) it has the lowest capital cost and lowest environmental impact; (3) it supports the BC Government's climate change objectives; and (4) is able to meet the BC Hydro Tariff obligation to serve interconnection customers.

Project Impacts and Benefits:	
BC Hydro will meet the expectations of its customers to be able to reliably serve new load. The completion of the project will serve a number of interconnection customers who are currently in the queue. The amount of CO_2 greenhouse gas avoidance will depend on the actual loads that would materialize.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: There is uncertainty with how fast customer loads will materialize. BC Hydro may choose to proceed with the project regardless of the individual customer decisions in order to provide sufficient capacity to meet the needs of customers currently in the queue and other potential customers who may request interconnections in the future.	

Investment Planning ID: 93958	**Project Name:** South Fraser Transmission Relocation Project	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Deferred	**Filing Reference:** F20-F21 RRA: • Appendix E, page 29 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 • CEC 3.104.1 F22 RRA: • Appendix Q, page 20	

Description:

The purpose of this project is to relocate certain sections of two 230 kV transmission circuits (Circuit 2L62 and Circuit 2L58) from their present location adjacent to Highway 99 and in the George Massey tunnel to accommodate the Ministry of Transportation and Infrastructure's planned replacement of the George Massey tunnel.

Key Drivers:

- Operational Requirements
- Reliability

Issues Being Addressed:

In order to accommodate Ministry of Transportation and Infrastructure's new crossing infrastructure, the existing transmission lines (2L062) needs to be relocated. These two 230 kV circuits form a critical part of BC Hydro's transmission network supplying power to customers in Richmond, Delta and the Greater Vancouver area. The type of transmission crossing (overhead or underground) will be reassessed based on the Province's August 2021 announcement that they plan to construct a new tunnel by 2030.

Discussion of Alternatives:

The project is currently on hold. BC Hydro will reassess alternatives for the relocation of 2L062 and 2L058 now that the Province has made their decision on their George Massey Tunnel replacement project.

Project Impacts and Benefits:

- Ensure continued service of reliable power to Delta and Richmond.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

This project began in 2014 when the Province initially announced its plans to replace the tunnel with a bridge and an overhead relocation of 2L062 was selected. The project was placed on hold in 2017 when the Province announced it was re-evaluating its crossing options for the tunnel replacement which could be either a new bridge or new tunnel. BC Hydro can re-evaluate alternatives for relocation of 2L062 and 2L058 now that the Province has decided on a solution for its project.

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="1">Investment Planning ID:
900243</td><td colspan="2">Project Name:
Sperling Metalclad Switchgear Replacement</td></tr>
<tr><td>Forecast Capital Cost:
$53.6 million</td><td>Forecast In-Service Date:
Fiscal 2025</td><td>Start Date of Construction:[1]
Fiscal 2020</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• Chapter 6, page 6-106
• Appendix I, Transmission - line 23, Appendix J, page 97, Appendix K, page 51 and 71
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-44
• Appendix I, Transmission - line 19
• Appendix Q, page 23
• BCOAPO IR 1.58.1</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to improve the reliability and reduce the safety risks at Sperling (SPG) substation.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Safety</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The SPG substation has a 60 series feeder section which consists of 12 kV bulk oil breakers and a lattice steel structure built for 4 kV prior to 1950. The 60 series feeder section and the bulk oil breakers in the 70/80 series feeder section have an Asset Health Index of Poor or Very Poor and are at end-of-life. One breaker in the feeder section has failed, and more breaker failures are expected in the near future. The 60 series feeder section also has insufficient Limits of Approach to protect worker safety. The existing lattice structure does not meet current seismic requirements and is at end-of-life due to aging and corrosion.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
BC Hydro considered five alternatives:
i. Do nothing and defer the work;
ii. Replace only the bulk oil breakers in the 60 series feeder section;
iii. Replace the existing 60 series feeder section, the bulk oil breaker in the 70/80 series feeder section and four end-of-life electromagnetic protection relays (non-arc resistant metalclad switchgears would be replaced with new arc-resistant switchgears);
iv. Decommission SPG substation and transfer load to other stations; and
v. Replace SPG substation with a new substation.
Alternative iii, Replace the existing 60 series feeder section, the bulk oil breaker in the 70/80 series feeder section and four end-of-life electromagnetic protection relays, was selected as the preferred alternative. The non-arc resistant metalclad switchgears will be replaced with new arc-resistant switchgears.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">Alternative i was not selected because it would not address the reliability and safety risks associated with the 60 series feeder section. Alternative ii was not selected because it would not address the issues with electrical clearances, fault level, and other aging equipment in the feeder section, such as the end of life disconnect switches, bus structure and steel lattice structures. Alternative iv was not selected because no substation in the area has sufficient feeder positions to take on the additional load. Alternative v was not selected because it would be cost prohibitive.</td></tr>
<tr><td colspan="2">Project Impacts & Benefits:
• Improved reliability of end-of-life equipment
• Improved worker safety</td></tr>
<tr><td>Project Implementation Phase Risk

Risk 1:
Due to the age of the substation, there is a risk of encountering unexpected buried cables/utilities. This could result in design changes, accidental damage to cables/utilities, forced outage, construction delays, and cost increase.

Risk 2:
Due to a complex construction and constrained work area there is a risk that construction activities cannot be completed as planned, resulting in construction delays and contractor delay claims.</td><td>Risk Treatment

Risk 1:
To mitigate this risk an underground Ground Penetrating Radar survey was completed during the Feasibility Design stage to locate underground utilities that could potentially conflict with routing of new cables. In addition, Hydro-Vac will be utilized in areas of concern during construction.

Risk 2:
To mitigate possible outage related issues, the project team has completed a staging plan with participation from Fraser Valley Operations; Field Operations, Communication, Protection and Control Technicians; Construction and Engineering. This staging plan will be included in tender documents. In addition, Solid Insulated Bus components will be utilized in congested areas.</td></tr>
<tr><td colspan="2">Additional Information:
N/A</td></tr>
</table>

<table>
<tr><td>Investment Planning ID:
902126</td><td colspan="2">Project Name:
Sunshine Coast - Transmission Reinforcement</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Future</td><td colspan="2">Filing Reference:
New</td></tr>
<tr><td colspan="3">Description:
This project is to install transmission reinforcements for the Sunshine Coast. This project addresses a transmission performance constraint which was identified through annual planning assessments.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Mandatory Reliability Standard TPL-001-4 2020 assessment of the Sunshine Coast regional transmission system identified voltage constraints caused by system contingencies.
Non-Consequential Load Loss at Pender Harbour substation is expected within 10 years planning horizon. This investment is a corrective action plan to address this system performance constraint.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
BC Hydro is considering three alternatives:
i. Malaspina transformer: Add a second 230/138 kV transformer at Malaspina substation;
ii. Sechelt shunt capacitors: Add 2X10 MVar Shunt capacitors at Sechelt substation; and
iii. Upgrade Sechelt substation: upgrade Sechelt substation o a 230 kV station by adding a new 230/138 kV transformer and looping in transmission line 2L47.
Alternative i, to add a new second 230/138 kV transformer at Malaspina substation, is the preferred alternative. This will mitigate the potential voltage constraints expected in the Sunshine Coast regional transmission system. “Do Nothing” has been rejected as this investment is required to meet the transmission performance criteria set by Mandatory Reliability Standard TPL-001-4.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
• Improve reliability by resolving the potential voltage constraints in Sunshine Coast transmission system during peak load periods.
• Comply with transmission planning system performance requirements</td></tr>
<tr><td colspan="2">Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="3">Additional Information:
N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: 900019	Project Name: System Wide – Bulk Electric System Telecom Equipment Replacement (formerly Various Sites – Microwave Radio Replacement)	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Identification	**Filing Reference:** F20-F21 RRA: • BCUC IR 1.133.1 Confidential F22 RRA: • Chapter 6, page 6-50 • Appendix I: Transmission - line 58	

Description:

The purpose of the project is to replace Bulk Electric System telecommunication equipment that is at the end of life throughout B.C., with the exception of Vancouver Island which is being addressed under a separate project (Vancouver Island Microwave Radio Replacement Project) that is currently in the Implementation phase.

Key Drivers:

- Reliability

Issues Being Addressed:

BC Hydro operates a province-wide telecommunication system to support the operation of BC Hydro's grid, in part by enabling Class 1 and 2 teleprotection and Remedial Action Scheme (**RAS**) services. The telecommunications system also provides Supervisory Control and Data Acquisition (**SCADA**), operational data, operational voice, asset health monitoring, remote engineering access, corporate data and security services to enable BC Hydro to manage and operate the power system.

This telecommunications system has been expanded incrementally to support the protection and control of new transmission lines, transmission and generating stations, and large customer interconnections. However, the majority of the equipment in the province was last replaced in the late 1990s/early 2000s and is at end of useful life.

The equipment is no longer sold or supported by the original manufacturer, and only limited support is still available from third-party service providers. It is increasingly challenging to find spares to repair faulty equipment. There has been an increase in outages, and despite equipment redundancy, some recent outages to network equipment have taken out both primary and secondary protection circuits. Failures of equipment at mountaintop sites are difficult to repair in a safe and timely manner, especially in the winter, and outages to telecommunications equipment can lead to the loss of SCADA, teleprotection and RAS signals. System Operating Orders direct that extended outages to teleprotection and RAS signals would require remedial actions on the power system, such as reducing generation output or the intertie capacity on various transmission lines between BC Hydro and other entities.

Discussion of Alternatives:

This project has a Single Viable Alternative. The components of the telecommunications system are at end of life and must be replaced. This alternative will replace end of life microwave radio, switching, and network equipment with new models whose manufacturers provide spare equipment and technical support. Multi-protocol label switching equipment will be added to enhance the efficient use of limited microwave radio capacity for Internet Protocol based services. This alternative would reduce the risk of failure of equipment at the end of its useful life, it would support the ability to replace or repair failed

1 Start Date of Construction is the Implementation Approval Date.

equipment with like models, and it would make more efficient use of the radio capacity we have. The alternative to obtain telecommunication services from third parties has been rejected, as BC Hydro would not be able to control the operation or repair of the third-party circuits. The use of these circuits would result in BC Hydro being unable to meet the availability and performance requirements of the SCADA, Teleprotection and RAS schemes.	
Project Impacts and Benefits: • Maintain reliability and capacity of the power system by addressing the telecommunication equipment end-of-life condition. • Reduce reliance on third-parties to provide spares and support.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: This investment was previously identified as Various Sites - Microwave Radio Replacement, but it was renamed to reflect that the scope now includes other telecom equipment, such as routers, switches, and network equipment. The individual telecom equipment components planned for replacement function together as a system. BC Hydro determined that replacing all the components together under a single project would be more efficient and have lower implementation risks. BC Hydro expects to file a section 44.2 application with the BCUC during the Definition phase of the project.	

<table>
<tr><td colspan="1">Investment Planning ID:
92183</td><td colspan="2">Project Name:
Vancouver Island Radio System</td></tr>
<tr><td>Forecast Capital Cost:
$32.5 million</td><td>Forecast In-Service Date:
Fiscal 2024</td><td>Start Date of Construction:[1]
Fiscal 2018</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• Chapter 6, page 6-115 and 6-116
• Appendix I, Transmission - line 56, Appendix J, page 111, Appendix K, page 78
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-50
• Appendix I, Transmission - line 55
• BCOAPO IR 1.57.3
• CEC IR 1.34.1.1</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to replace end-of-life microwave radio and associated equipment and extend the Multi-Protocol Label Switching network to Vancouver Island. Multi-Protocol Label Switching is a network technology that increases the efficiency of transporting Telemetry and Control, Corporate LAN, voice, and operational traffic.
In addition, the microwave system will be extended to Gold River (GLD) substation through a new off-grid Microwave Repeater on Strathcona Mountain substation and a new passive repeater John Rae Newstead substation. The project involves work at a total of 38 facilities.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
BC Hydro operates a province-wide private telecommunications system to support the operation of the Bulk Electric System. The telecom system enables high-speed line protection and control of the transmission system. The telecom equipment on Vancouver Island is the oldest in the BC Hydro system and is experiencing an increased rate of failures. The issues and risks associated with the BC Hydro Telecommunication system on Vancouver Island include:
• Equipment reliability and repair issues due to aging equipment that is no longer manufactured or supported by the manufacturer; and
• Owing to capacity constraints with the existing system, BC Hydro cannot support increasing communication needs.</td></tr>
</table>

1 Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives: BC Hydro considered two alternatives: i. **Replace** equipment that has not been supported since 2018 and extend the microwave network to GLD substation; and ii. **Do nothing:** Continue to use the existing end-of-life telecom equipment and continue performing repairs. Alternative i, replace equipment that has not been supported since 2018 and extend the microwave network to GLD substation, was selected as the preferred alternative as it will improve system reliability, ensure sufficient capacity on the Vancouver Island Power Line Carrier system, and provide increased bandwidth to GLD substation. Alternative ii was not selected because of the increased number of failures of the existing telecom equipment that has reached end of life and is no longer supported by the manufacturer.	
Project Impacts and Benefits: • Improve reliability of the microwave radio system. • Improve operating capacity of the microwave radio system. • Salvage end-of-life telecom equipment to use as spares for the rest of the province.	
Project Implementation Phase Risk: This project currently does not have any identified Zone 3 (high) Implementation Phase risks	**Risk Treatment:** N/A
Additional Information: N/A	

Investment Planning ID: 901592	Project Name: Various Sites – NERC CIP 003v7 Implementation[1]	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** Fiscal 2024	**Start Date of Construction:**[2] Fiscal 2022
Development Phase: Definition	**Filing Reference:** F22 RRA: • Chapter 6, page 6-47 • Appendix I: Transmission - line 41 • RCIG IR 1.8.6	

Description:

This project is required to install equipment and establish processes, practices, and procedures to ensure that BC Hydro is compliant with Critical Infrastructure Protection (**CIP**) CIP-003-8 Mandatory Reliability Standards (**MRS**) on all low impact Bulk Electric System (**BES**) Cyber Assets.

Key Drivers:

- Reliability
- Reputational
- Financial Loss

Issues Being Addressed:

The CIP-003-8 MRS was adopted in B.C. by BCUC Order No. R-19-20 in September 2020. BC Hydro must comply with all the CIP-003-8 MRS on a staged basis per the BCUC-adopted CIP-003-8 Implementation Plan in lead up to October 1, 2023. This project is intended to bring BC Hydro into compliance with the CIP-003-8 MRS by October 1, 2023, in the following four areas:

i. Electronic Access Controls – Monitoring systems for generation and transmission stations that contain low impact BES cyber assets connected to untrusted networks are required. Eighty-one sites require the installation of dial-up Electronic Access Controls (i.e., firewalls for cyber assets connected by telephone lines) and 53 sites require the installation of external routable connection access controls (i.e., firewalls that are commonly used in network security systems);

ii. Physical Access Controls – Measures designed to prevent unauthorized access to BES cyber assets/systems in generation and transmission stations are required. One hundred thirty-three sites require the installation of physical key management systems and 26 sites require physical access controls (i.e., card readers, cameras, alarms);

iii. Information Technology in 2021 – Deployment of additional dedicated-secure laptops for connecting to CIP cyber assets/systems; hardening of existing laptops to ensure they comply with CIP MRS; and training of personnel on the protocols and procedures for using these secure laptop computers in accordance with CIP MRS is required. The compliance date mandated by the BCUC for this work is October 1, 2021; and

iv. Information Technology in 2023 – Assessment and upgrade of enterprise systems, and update of corporate CIP policies, plans and procedures for the access and use of low impact BES cyber assets is required.

---

1 This project was initiated when the CIP-003-7 MRS was issued which represented “Version 7” of the MRS. This MRS was revised to CIP-003-8 “Version 8” by BCUC Order No. R-19-20.

2 Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives:	
BC Hydro considered three alternatives: i. **Defer**; ii. **Do Nothing**; and iii. **Implement four work streams to address the four areas identified above**. Alternative iii, implement four work streams, is the selected as the preferred alternative that will bring BC Hydro into compliance with the CIP-003-8 MRS by October 2023. Alternative i was not considered viable as deferring the project increases the risk that BC Hydro would not be in compliance by the regulatory deadline. Alternative ii was not considered viable because taking no action to implement security management controls to protect bulk electric system cyber systems within generating and transmission stations would not be compliant with the CIP-003-8 MRS.	
Project Impacts and Benefits: • Meet regulatory (CIP-003-8 MRS) requirements. • Improve overall cyber security of BES Cyber Assets. • Mitigate risk of financial penalties for non-compliance	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: N/A	

Investment Planning ID:	Project Name:	
902241	Various Sites – Telecom Transport Network Resiliency Enhancement	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** New	

Description:

BC Hydro owns and operates a telecom network in order support the Bulk Electric System, providing high-availability Supervisory Control and Data Acquisition, Teleprotection and Remedial Action Scheme (**RAS**) services. The objective of this project is to build redundant network links between high-priority Bulk Electric System stations to eliminate single points of failure for certain critical telecom circuits. The elimination of single points of failure would increase the availability of the Teleprotection and RAS circuits, and it would decrease the likelihood of telecom outage events requiring power system actions. It would also simplify cutover during equipment replacement projects and reduce the capital and maintenance costs associated with designing highly-available telecom paths.

Key Drivers:

- Reliability
- Safety

Issues Being Addressed:

Although the telecom network is engineered to have high reliability, there are many single points of failure, primarily located at mountaintop locations. There remains a risk that a failure at a mountaintop site could not be repaired promptly and would lead to an extended telecom outage that would require actions on the power system such as reducing generation and reducing the capacity of intertie lines with third parties. There have been recent incidents where smoke, ice, hail and equipment failures have led to extended telecom outages at mountaintop sites. The impact to the power system resulting from failed telecom circuits is increasing due to increased generation and load on the grid, so the risk of single points of failure is higher now than previously.

A failure of telecom equipment and circuits requires the rapid dispatch of crew to repair the fault. System Operating Orders define the power system response that must be undertaken if the repair cannot be affected within a certain time limit. Typical actions include reducing output at generation stations or transfer capacity on interconnections with other entities. For the most critical circuits, the typical permitted time limit to affect a repair is four hours. For remote mountaintop repeaters, accessing and repairing faults within four hours can be difficult under ideal conditions. In the winter or under storm conditions, it may not be safe or possible to access the site before power system actions are required.

Discussion of Alternatives:

BC Hydro is considering four alternatives:

i. **Obtain dark fiber from carriers:** Build fiber optic cable entrances from substation control rooms to demarcation point on carrier poles. Connect telecom electronics to fiber optic cables. This option has OMA implication as it requires dark fiber agreement for connections between key substations;

ii. **Build redundant network:** Build new BC Hydro owned telecom facilities across the province, based either on microwave or fiber optic technologies. This option would have a significant cost and is most likely not viable;

iii. **Obtain telecommunications services from a Telecom Carrier:** Services from telecom carriers currently have technical limitations that make them incompatible with the operation of Teleprotection and RAS circuits. This alternative may not be viable due to this limitation; and

[1] Start Date of Construction is the Implementation Approval Date.

iv. **Do Nothing:** Continue to design, sustain and operate critical microwave sites as single points for failure for the telecom system. Manage the risk of failure of a site for longer than four hours.

Project Impacts and Benefits:

- Reduce the capital and maintenance costs associated with building and maintaining highly-available microwave repeaters at mountaintop locations.
- Reduce the equipment requirements and simplify the circuit cutovers for equipment replacement projects.
- Reduction of the impact to the power system of a long-term failure (>4hrs) of a microwave site.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

N/A

<table>
<tr><td colspan="1">Investment Planning ID:
900598</td><td colspan="2">Project Name:
West End – Substation Construction and System Reinforcement</td></tr>
<tr><td>Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
Amended F12-F14 RRA:
Application: pages 6-17, 6-24, 6-63, 6-64
BCUC IRs 1.181.1 Attachment 1, 1.265.1, 2.101.2, 2.102.1, 2.123.1 Attachment 1
BCOAPO IR 1.38.1 Attachment 2
CEC IR 1.25.1 Attachment 1
F2014 Annual Report to the BCUC:
Appendix I, line 20;
Appendix J, page 46.
F17-F19 RRA:
Appendix I, line 14, Appendix J, page 51
BCUC IRs 1.70.3, 1.104.1-1.104.3, 2.249.8, 2.253.2, 2.260.4, BCOAPO IR 1.36.1
F20-F21 RRA:
Chapter 6, page 6-102
Appendix H, page 14
Appendix I, Transmission - line 8, Appendix J, page 80, Appendix K, page 54
BCUC IRs 1.115.2, 1.117.1, 1.117.1.1, 1.117.2, 1.117.3, 1.133.1 Confidential
BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
Chapter 6, page 6-36
Appendix I, Transmission - line 5
BCUC IR 1.45.2
CEC IR 1.34.1.1</td></tr>
<tr><td colspan="3">Description:
This project will build a new 230 kV to 25 kV, 400 MVA (ultimate capacity), underground substation in the West End neighbourhood of Downtown Vancouver as part of the first stage of the 30-year Downtown Vancouver Electricity Supply Plan.
Refer to Appendix K – Downtown Vancouver Electric Supply Plan for additional information.</td></tr>
<tr><td colspan="3">Key Drivers:
Reliability</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Issues Being Addressed:

The Downtown Vancouver area is comprised of the Downtown, West End, Strathcona, and Grandview-Woodland neighborhoods. The area is supplied by a 230 kV and 69 kV transmission network and three substations:

- Cathedral Square substation (built in 1984);
- Dal Grauer substation (built in 1953); and
- Murrin substation (built in 1947).

There are a number of risks and issues at the aging Dal Grauer and Murrin substations. More than half of the assets are expected to degrade to an Asset Health Index of Poor or Very Poor in the next 10 to 20 years, presenting elevated safety and reliability risks. Murrin substation is on seismically unstable soil. Approximately half of the 230 kV switchyard, which supplies both Murrin and Dal Grauer loads, is vulnerable to severe earthquake damage from liquefaction and settlement. Physical space constraints at Dal Grauer make redevelopment of the substation in its current location a challenge.

The long-term strategy for the area is to mitigate the reliability and safety risks by replacing the Dal Grauer and Murrin substations with new substations. The first of these is the West End Substation.

Discussion of Alternatives:

The ultimate capacity of the underground substation will be 400 MVA, located in the West End neighborhood of Downtown Vancouver. The project will consider different options for the size of the substation before it begins construction, given that the 400 MVA capacity may not be required immediately.

Project Impacts and Benefits:

- Improve West End Vancouver area reliability.
- Minimize future worker safety risks in the Dal Grauer and Murrin substations.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase, further developed in the Definition Phase and finalized as the project reaches the Implementation Phase.	To be determined as the project reaches Implementation Phase.

Additional Information:

See also Appendix Js for the related projects:

- Investment Planning ID: 900266; Project Name: East Vancouver - Substation Construction; and
- Investment Planning ID: 900219; Project Name: DVES: West End Substation – Property Purchase.

<table>
<tr><td colspan="2">Investment Planning ID:
94034 and 94032</td><td colspan="2">Project Name:
West Kelowna Transmission and Westbank [Substation] Upgrade Projects</td></tr>
<tr><td colspan="2">Forecast Capital Cost:
To be determined</td><td>Forecast In-Service Date:
To be determined</td><td>Start Date of Construction:[1]
To be determined</td></tr>
<tr><td colspan="2">Development Phase:
Identification</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I, lines 9 and 35, Appendix J page 46 and page 62
• BCUC IRs 1.70.3, 1.101.1-1.101.6, 2.249.8, 2.249.14, 2.260.4
• BCOAPO IRs 1.36.1, 2.77.1, 2.83.1
• CEC IR 1.72.3.2
F20-F21 RRA:
• Chapter 6, page 6-102
• Appendix H, page 14
• Appendix I, Transmission - line 6
• BCUC IRs 1.115.1, 1.115.2, 1.133.1 Confidential, 3.291,7
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
• CEC IR 3.104.1, 1.105.1
F22 RRA:
• Chapter 6, page 6-36
• Appendix I, Transmission - line 6
• BCUC IRs 1.47.1, 1.47.2 and 1.45.2
• CEC 1.39.2.1</td></tr>
<tr><td colspan="4">Description:
West Kelowna Transmission Project:
The West Kelowna Transmission Project will provide full electricity supply redundancy to the City of West Kelowna, the District of Peachland and Westbank First Nation to manage increasing reliability risk.
Westbank Substation Upgrade Project:
The Project will increase Westbank Substation firm transformation capacity and replace end of life assets on an expanded footprint. Space provisions will be made as part of the Project to accommodate a new secondary transmission line (see above) and an additional 50 MVA feeder section.</td></tr>
<tr><td colspan="4">Key Drivers:
West Kelowna Transmission Project:
• Reliability
Westbank Substation Upgrade Project:
• Reliability</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Issues Being Addressed:

The West Kelowna area is located in the Okanagan Valley on the west bank of the Okanagan Lake and has serves approximately 22,000 BC Hydro customers. The West Kelowna area is serviced by a single 138/25 kV substation (Westbank Substation) that is supplied by a single 80 km, radial 138 kV transmission line from Nicola Substation in the Nicola Valley. Westbank Substation is the second largest distribution station in the BC Hydro system supplied by a radial transmission line. Westbank Substation has no ties to any other substations and there is no local generation. Consequently, if the transmission line is removed from service the substation will lose supply and not be able to serve local customers.

West Kelowna Transmission Project

Since 1994 there have been three sustained forced outages; one in 1994 caused by lightning resulting in a six-hour outage; one in October 2007 caused by lightning resulting in a seven-hour outage; and the October 2014 pole-top fire related outage resulting in a nine-hour outage. The single outage in 2014 resulted in significant Customer Hours Lost (**CHL**) (180,000) for West Kelowna. The CHL consequence due to an outage in the area is significant and indicated that BC Hydro should address this risk. Other factors that contribute to the challenge of restoring power include the length of the existing transmission line, its location in rugged and remote terrain, and susceptibility to forest fires and landslides.

While the existing line is considered reliable, adding a new, second transmission line (or cable) will provide redundancy to the system, ensuring continued, reliable power in the event of an outage on the existing line.

Westbank Substation Upgrade Project

The peak summer load at Westbank Substation exceeds the firm summer capacity of the station. Several components of the substation are also reaching end of life. This includes one 138 kV oil circuit breaker and one 25 kV oil circuit breaker, two circuit switchers and one voltage transformer.

Discussion of Alternatives:

West Kelowna Transmission Project

Over the life of the Project, three alternatives have been explored:

i. **BC Hydro Transmission:** new transmission line connecting Westbank Substation to BC Hydro's transmission system;

ii. **BC Hydro & Fortis Transmission:** new transmission line connecting Westbank Substation to FortisBC's transmission system; and

iii. **Resiliency:** improving resiliency of the existing transmission line supplying Westbank Substation.

All of the alternatives have been evaluated on cost, reliability, environment, safety, and First Nations and stakeholder benefits / impacts through a Structured Decision-Making process. Alternative i, was selected as the leading alternative in 2016. Upon further study the cost estimate to build the new transmission line increased to more than double the original estimate. Given this cost increase it is prudent to re-evaluate the alternatives and consider any potential new alternatives available. Alternative ii is being re-evaluated.

Westbank Substation Upgrade Project

BC Hydro considered three alternatives:

i. **Upgrade Westbank Substation** to increase firm transformation capacity, replace end of life assets and add space provision to interconnect the new transmission line;

ii. **Build a new substation** to accommodate load growth in the West Kelowna area; and

iii. **Do nothing:** continue as usual, with curtailment of customer load during transformer contingency.

Alternative i, Upgrade Westbank Substation, was selected as the Single Viable Alternative that meets the objectives. Alternative, ii, Building a new substation, would be at a much greater cost, and was therefore considered an unnecessary alternative.

Project Impacts and Benefits:

West Kelowna Transmission Project:

- Improve reliability in West Kelowna by providing redundancy to the system.

Westbank Substation Upgrade Project:

- Increase firm transformation capacity to meet demand.
- Replace end of life assets on an expanded footprint.
- Space provisions for a new transmission line position and a 50 MVA feeder section.

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

In Directive 3 of the BCUC's Decision on the F2017 to F2019 Revenue Requirement Application, BC Hydro was directed to file a Certificate of Public Convenience and Necessity application for both the West Kelowna Transmission Project and Westbank Substation Upgrade Project. The BCUC also found these two projects to be sufficiently linked that they could be expediently reviewed in one process. The decision provides some flexibility for BC Hydro to have the two projects reviewed in a single process or separately if necessary.

Program of Projects Name: H-Frame Elimination - Gastown		
Appendix I Reference: Distribution, page 5, line 17		
Investment Planning ID: 900391	**Project Name:** Downtown Vancouver - Underground Murrin Feeders to Eliminate H-Frames in Gastown	
Forecast Capital Cost: $26.6 million	**Forecast In-Service Date:** Fiscal 2022	**Start Date of Construction:**[1] Fiscal 2019
Development Phase: Implementation	**Filing Reference:** F20-F21 RRA: • Chapter 6, page 6-129 • Appendix I, Distribution - line 25 • BCUC IRs 1.113.2.1 and 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-64 • Appendix I, Distribution - line 17	
Description of Program of Projects: The objective of this Program of Projects is to reduce the risk of public contact incidents associated with the distribution lines built on H-frame structures located in back lanes in the Gastown area of Downtown Vancouver. Approximately 37 H-frame structures will be removed by constructing new underground feeders and relocating overhead feeders and services to the new underground system. This will include the installation of new automated switchgear and street vaults, as well as underground cables to connect these units and serve customers. These projects are being delivered as a program to allow BC Hydro to quickly adjust plans and projects to optimally respond to the dynamic nature of the distribution system and to opportunities presented to reduce cost or prioritize projects as a result of ongoing development, load growth, and/or customer initiatives.		

1 Start Date of Construction is the Implementation Approval Date.

Issues to be addressed:
This Program of Projects will address safety hazards with H-frame structures in back lanes of Gastown which violate current electrical clearance codes and standards. These structures have primary conductors that do not meet current safety clearances relative to the existing buildings. The close proximity of energized conductors to fire escapes and windows in the back lanes of buildings poses a significant safety risk to the public. In many of the narrow back lanes, it is not possible to bring the H-frame system into compliance with current safety clearance codes and standards due to lack of space. Considering the high consequence of electrical contact with members of the public, the decision was made to eliminate the H-frame structures. Benefits that will be achieved through completion of this program include: • Relocating electrical equipment underground in new civil infrastructure to reduce potential public electrical contact hazard, mitigate the risk of vandalism, and improve visual aesthetics; and • Expansion of the open loop system to mitigate reliability risk to customers and improve worker safety.
Schedule of Program of Projects:
This program of projects has a planned in-service date of March 31, 2022. For individual projects, the in-service dates are: • LM-VAN-025 Primary Removal Gastown South: January 31, 2022; • LM-VAN-037 Primary Removal Gastown Middle: January 31, 2022; • LM-VAN-038 Primary Removal Gastown North: January 31, 2022; • LM-VAN-124 Secondary Removal Gastown South: March 31, 2022; • LM-VAN-125 Secondary Removal Gastown Middle: March 31, 2022; • LM-VAN-126 Secondary Removal Gastown North: March 31, 2022; and • LM-VAN-025A Automation: January 31, 2022.
Risks and Mitigation Strategies:
The timely procurement of long lead time underground equipment (vaults, submersible transformers and switchgear). Any delays in procuring equipment may delay construction schedules. This risk is being mitigated by placing early pre-orders of long lead time equipment. Identifying acceptable locations for underground vault and above ground control enclosures with the City of Vancouver and impacted stakeholders. This is a challenge due to the congested underground infrastructure in Downtown Vancouver. This risk is being mitigated through regular interactions with the City of Vancouver and impacted stakeholders during the design phase. There are challenges with negotiating upgrades to customer-owned secondary electrical infrastructure due to a lack of interest or responsiveness from some customers, or difficulty in identifying or contacting building owners (e.g., owners may reside outside B.C. or Canada or the building may be owned by a numbered company). This risk is being mitigated through BC Hydro's Community Engagement team involvement in working with the design team and Key Account Managers to help identify building owners, communicate the project objectives, identify the required building modifications and work to obtain signed new Electric Service Agreements. Other construction challenges include limited resources to perform civil work, management of vehicle and pedestrian traffic, congestion with other underground utilities, and limited working hours for construction. These risks are being mitigated by early and frequent engagement with the City of Vancouver and the local Business Improvement Association.
Additional Information:
N/A

Program of Projects Name: H-Frame Elimination - Chinatown		
Appendix I Reference: Distribution, page 6, line 18		
Investment Planning ID: 900557	**Project Name:** H-Frame Elimination – Chinatown	
Forecast Capital Cost: $48.4 million	**Forecast In-Service Date:** Fiscal 2022	**Start Date of Construction:**[1] Fiscal 2016
Development Phase: Implementation	**Filing Reference:** F20-F21 RRA: Chapter 6, page 6-129 • Appendix I, Distribution - line 21, Appendix J, page 118 • BCUC IRs 1.113.2.1, 1.133.1 Confidential and 2.258.2 • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-64 • Appendix I, Distribution - line 18 • CEC IR 1.34.1.1	
Description of Program of Projects: The objective of this Program of Projects is to reduce the risk of public contact incidents associated with the distribution lines built on H-frame structures located in back lanes in the Chinatown area of Downtown Vancouver. Approximately 110 H-frame structures will be removed by constructing new underground feeders and relocating overhead feeders and services to the new underground system. This will include the installation of new automated switchgear and street vaults, as well as underground cables to connect these units and serve customers. These projects are being delivered as a program to allow BC Hydro to quickly adjust plans and projects to optimally respond to the dynamic nature of the distribution system and to opportunities presented to reduce cost or prioritize projects as a result of ongoing development, load growth, and/or customer initiatives.		

1 Start Date of Construction is the Implementation Approval Date.

Issues to be addressed:
This Program of Projects will address safety hazards with H-frame structures in back lanes of Chinatown which violate current electrical clearance codes and standards. These structures have primary conductors that do not meet current safety clearances relative to the existing buildings. The close proximity of energized conductors to fire escapes and windows in the back lanes of buildings poses a significant safety risk to the public. In many of the narrow back lanes, it is not possible to bring the H-frame system into compliance with current safety clearance codes and standards due to lack of space. Considering the high consequence of electrical contact with members of the public, the decision was made to eliminate the H-frame structures. Benefits that will be achieved through completion of this program include: • Relocating electrical equipment underground in new civil infrastructure to reduce potential public electrical contact hazard, mitigate the risk of vandalism, and improve visual aesthetics; and • Expansion of the open loop system to mitigate reliability risk to customers and improve worker safety.
Schedule of Program of Projects: This program of projects has a planned in-service date of March 31, 2022. For individual projects, in-service dates are: • LM-VAN-006 Primary Removal Chinatown West: April 3, 2018 (completed); • LM-VAN-007 Primary Removal Chinatown North: March 27, 2018 (completed); • LM-VAN-008 Primary Removal Chinatown East: March 20, 2020 (completed); • LM-VAN-055 Primary Removal Chinatown South: March 20, 2020 (completed); • LM-VAN-058 Secondary Removal Chinatown West: March 31, 2021; • LM-VAN-059 Secondary Removal Chinatown North: July 24, 2020 (completed); • LM-VAN-060 Secondary Removal Chinatown East: December 31, 2021; • LM-VAN-061 Secondary Removal Chinatown South: July 31, 2021; • LM-VAN-006A Automation and Fiber: February 21, 2020 (completed); and • LM-VAN-058A Dismantling: March 31, 2022.

Risks and Mitigation Strategies:
• The timely procurement of long lead time underground equipment (vaults, submersible transformers and switchgear). Any delays in procuring equipment may delay construction schedules. This risk is being mitigated by placing early pre-orders of long lead time equipment. • Identifying acceptable locations for underground vault and above ground control enclosures with the City of Vancouver and impacted stakeholders. This is a challenge due to the congested underground infrastructure in Downtown Vancouver. This risk is being mitigated through regular interactions with the City of Vancouver and impacted stakeholders during the design phase. • There are challenges with negotiating upgrades to customer-owned secondary electrical infrastructure due to a lack of interest or responsiveness from some customers, or difficulty identifying or contacting building owners (e.g., owners may reside outside B.C. or Canada or the building may be owned by a numbered company). This risk is being mitigated through BC Hydro's Community Engagement team involvement in working with the design team and Key Account Managers to help identify building owners, communicate the project objectives, identify the required building modifications and work to obtain signed new Electric Service Agreements. • Other construction challenges include limited resources to perform civil work, management of vehicle and pedestrian traffic, congestion with other underground utilities, and limited working hours for construction. These risks are being mitigated by early and frequent engagement with the City of Vancouver and the local Business Improvement Association.
Additional Information: N/A

Investment Planning ID: 900541	Project Name: Vancouver Island - Saltspring 25F61 Cable Extension to North Pender Island (VI-GUL-005)	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** F22 RRA: • Chapter 6, page 6-62 • Appendix I, Distribution - line 13	

Description:

The purpose of this project is to improve the reliability of the islands of Mayne, Saturna, and Pender, that are part of the Gulf Islands off the eastern coast of Vancouver Island.

These islands are supplied from two BC Hydro substations, one on Salt Spring Island and one on Galiano Island. Electricity to Mayne, Saturna and Pender islands is supplied by either of these two substations via a two-circuit intertie consisting of overhead and underwater (submarine cables) infrastructure. The two-circuit intertie serves as an electrical loop, referred to as the Gulf Island Loop, such that one circuit can provide the supply if the other fails or has a forced outage.

Key Drivers:

- Reliability

Issues Being Addressed:

This project will address reliability to the Gulf Island Loop. Due to the geographical challenges involved in serving the islands, long outages are a regular occurrence to various sections of the Gulf Island Loop. As a result, these two circuits have historically been among the worst performing circuits in the province. The reliability is expected to degrade further as the winter peak loading on the circuits has grown to a level that in the event of an outage to one circuit the other circuit does not have enough capacity to supply the load of these three islands.

Discussion of Alternatives:

The long-term plan for the Gulf Island Loop includes making improvements to address poor reliability, as well as adding capacity to the Gulf Island Loop. The new submarine cable will bring enough capacity to offload an additional 4 MW from the circuit supplying Pender Island.

BC Hydro is considering four alternatives:

i. **Adding an additional circuit** to the Gulf Island Loop to convert the loop from a two-circuit supply to a three-circuit supply. Several cable routes are possible to complete this alternative which would result in increased capacity, and improved reliability;

ii. **Extension of the existing submarine cable** from Mayne Island to Pender Island. This would provide a moderate improvement in reliability by improving the sectionalisation of the system; i.e. improve the ability to divide the loop into sections to isolate problem areas and minimize customer impacts. However, it would still be a two-circuit supply and it would not provide any additional capacity for the Gulf Island Loop system;

iii. **New Pender Island Substation.** This alternative would involve building new transmission to Pender Island and constructing a new substation. This would provide capacity and reliability improvements; however, it requires the largest capital investment and the most amount of time to implement; and

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">iv. Distribution Battery Storage Backup. This alternative uses developing technology and additional study would be needed to determine if this option would have enough storage capacity capable of providing backup for the duration of time that is typical of permanent outages on the Gulf Island Loop system.</td></tr>
<tr><td colspan="2">Project Impacts and Benefits:
• Improve reliability of the Gulf Island Loop.
• Ensure future load growth in the area can be supported.</td></tr>
<tr><td>Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="2">Additional Information:
N/A</td></tr>
</table>

Investment Planning ID: 900556	Project Name: Various Sites – LED Street Light Conversion	
Forecast Capital Cost: $74.9 million	**Forecast In-Service Date:** Fiscal 2024	**Start Date of Construction:**[1] Fiscal 2018
Development Phase: Implementation	**Filing Reference:** F20-F21 RRA: • Chapter 6, page 6-131 • Appendix I, Distribution - line 26, Appendix J, page 120 • BCUC IRs 1.133.1 Confidential and 2.258.2 • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-66 • Appendix I, Distribution - line 19	

Description:

This project involves the mass conversion of approximately 90,000 mostly high-pressure sodium streetlights and approximately 370 of the mostly mercury vapor private outdoor lights to LED lights. The remaining 4,600 private outdoor lights will be removed from the system as part of this project.

Key Drivers:

- Reputational
- Environmental

Issues Being Addressed:

This Project will address the following:

- Compliance with federal Polychlorinated Biphenyl (**PCB**) Regulations;
- Mitigation of increasing support and maintenance costs;
- Improvement of customer service and experience; and
- Increased data and billing accuracy.

Discussion of Alternatives:

BC Hydro considered four alternatives:

i. **Status Quo:** reactive replacement of failed streetlights and private outdoor lights with new bulbs or fixtures. This alternative was rejected due to not meeting Federal PCB regulatory requirements;

ii. **Reactive Replacement:** Replacement of failed streetlights/private outdoor lights or streetlights/private outdoor lights containing PCBs in a concentration of 50 ppm or more with new PCB free high-pressure sodium streetlights. Remove 4,600 private outdoor lights from the system;

iii. **Reactive Upgrade:** Conversion of failed streetlights/private outdoor lights or streetlights/private outdoor lights containing PCBs in a concentration of 50 ppm or more with new LED streetlights. Remove 4,600 private outdoor lights from the system; and

iv. **Proactive Replacement**: Mass conversion of all streetlights and 370 private outdoor lights to LED streetlights. Remove 4,600 private outdoor lights from the system.

Alternative iv, was selected as the leading alternative. It addresses the four key issues identified above: it meets the regulatory requirement, has the lowest lifecycle costs, provides the best customer service and experience, and is technically superior. It also meets the environmental and safety objectives. The other

[1] Start Date of Construction is the Implementation Approval Date.

alternatives considered are less efficient and more costly, and do not necessarily meet regulatory compliance and/or improve customer experience and service.	
Project Impacts and Benefits: All street lights and private outdoor lights replaced with higher efficiency LEDs or removed from the system (private outdoor lights only) resulting in: compliance with Federal PCB Regulations; reduction in annual street light maintenance costs; and improved customer experience with improved lighting, less outages and accurate billing. The conversions to LED will result in savings of approximately 32 GWh per year.	
Project Implementation Phase Risk: • **Reputational Risk** with Customers unsatisfied with new LED rates. • **Financial Risk** with the cost of using internal Power Line Technicians capable of completing more complex work being more expensive than Contractor crews in performing this work. • **Reputational and Financial Risks** with fines due to lack of compliance with meeting Federal PCB deadline for removing all units with PCB before December 31, 2025. Some units could be missed as they may not be included in BC Hydro's databases. Add risks for completeness. • **Reputational Risk** of delay in obtaining new street light rate for LEDs.	**Risk Treatment:** • Engage customers early and consult with customers to communicate the costs and benefits of the program and to ensure adequate financial constraint of program costs. • Contractors have been deployed in all parts of the province to complete the work and internal crews are assigned higher complexity work outside of this program where available. • A mass replacement approach is being used to sweep areas to find any units not in BC Hydro databases and replace these additional units to ensure compliance. • Interim rate requested and received from BCUC to ensure that conversions can occur before a final rate.
Additional Information: N/A	

Investment Planning ID: T002016 (formerly 901654)	Project Name: Advanced Distribution Management System Replacement	
Forecast Capital Cost: $ 11 million	**Forecast In-Service Date:** Fiscal 2023	**Start Date of Construction:**[1] Fiscal 2022
Development Phase: Definition	**Filing Reference:** F22 RRA: • Appendix I, Technology - line 4	

Description:

A Distribution Management System (**DMS**) is needed to assist Real-Time Operations and field operating personnel with the monitoring and control of the electric distribution system. This project will extend BC Hydro's existing suite of systems to include an Advanced Distribution Management system (**ADMS**), replacing the existing, end-of-life DMS.

Key Drivers:

- Risk reduction
- Capability enhancement

Issues Being Addressed:

- Reliability risk from continued operation of an end-of-life DMS system. The current DMS software and hardware is now at end-of-life.
- Enable distribution management capabilities:
  - Support increased Real-Time Operations responsibilities due to growth in distribution assets;
  - Allow Real Time Operations to monitor and control the distribution system in real-time using the same systems as deployed for transmission real-time monitoring and control. In this way, operators will be able to seamlessly navigate between distribution stations views and feeder network views which will further improve safety and reliability; and
  - Enable support for Transmission and Distribution Operations functions including volt/VAR optimization, planned outage management and restoration, safety procedures management, and management of distributed energy resources.

Discussion of Alternatives:

BC Hydro evaluated the following two alternatives:

i. Extend the existing suite of management systems to include an ADMS, replacing the existing, end-of-life DMS, and

ii. Replace the existing suite of management systems with another vendor's single integrated Energy Management System (**EMS**) and ADMS.

Alternative i was chosen after it was determined that extending the existing suite of management systems was the only solution that could meet the requirement of a single integrated control system at reasonable cost and risk. This alternative will prepare BC Hydro for the future with a foundational platform that will support integration with demand response, vehicle to grid management and other "behind the meter technologies".

Alternative ii was ruled out because the cost to BC Hydro to completely replace the existing suite of management systems would be significantly higher and carry a high risk of disruption to the electric system operation and reliability.

[1] Start Date of Construction is the Implementation Approval Date.

Project Impacts & Benefits:

- Risk Reduction achieved through:
  - Further utilization of automation devices and smart meters during critical events such as major storms and disasters;
  - Simplifying safety processes and reducing manual activities, which is expected to reduce near-miss incidents; and
  - Integrating distribution and low-voltage substation management and monitoring functions to improve decision making and maintain safety standards for control centre operation
- Productivity Improvement:
  - Synchronization of EMS and DMS information in real-time;
  - Optimizing distribution system monitoring control and operation, and utilizing non-wire solutions such as distributed energy resources, demand response, energy conservation, and vehicle to grid management;
  - Improvement in planned outage management and faster restoration for unplanned outages; and
  - Improvement in service voltage management (power quality).

Project Implementation Phase Risk:	**Risk Treatment:**
This project is not yet in Implementation.	To be determined when the project reaches Implementation

Additional Information:

Start date of Implementation is expected during fiscal 2022.

Investment Planning ID: T001397	**Project Name:** Contact Centre Technology Foundation	
Forecast Capital Cost: $ 23.6 million	**Forecast In-Service Date:** Fiscal 2023	**Start Date of Construction:**[1] To be determined
Development Phase: Identification	**Filing Reference:** F20-F21 RRA: • Application, pages 6-153, 6-154 • Appendix I, line 7 • Appendix L, pages 13, 24 • Exhibit B-29, page 3 • BCUC IRs 1.97.1 and 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Application, pages 6-74, 6-75 • Appendix I, line 4 • Appendix F, pages 14, 25, 26 • BCUC IR 1.50.2 • CEC IRs 1.45.1 CONF, 1.45.1 PUB, 1.45.2, 1.45.3	

Description:

The Contact Centre Technology Foundation project will address end-of-life Contact Centre Information Technology (**IT**) assets. The project will implement modern contact centre technologies to provide a stable and capable IT platform for all of BC Hydro’s contact centres.

Key Drivers:

- Risk reduction
- Capability enhancement

Issues Being Addressed:

The following issues will be addressed as part of this project:

1. Technology Obsolescence
   - BC Hydro’s current Contact Centre systems are considered by the vendor to be obsolete[2]. Although still functional, these IT systems are increasingly unstable and unable to meet growing business needs.
2. System Stability & Reliability Risk
   - Since the Contact Centre systems are considered obsolete, there is limited support from the vendor and only critical fixes are provided.
   - The existing solution does not have the capacity and flexibility to handle the increased call volumes seen during large scale power outages. For example, on a typical day the contact centre receives 500 trouble calls, this can increase to more than 50 times the volume during large scale outage events.

[1] Start Date of Construction is the Implementation Approval Date.

[2] Approximately $10.7 million was invested from 2015-2017 for Contact Centre system upgrades ($9.2 million capital and $1.6 million IOMA), of which $6.5 million was to maintain vendor support without adding new capabilities.

- BC Hydro's small regional centers have also experienced system reliability issues impacting the ability for customers to contact Customer Connections and the availability of call centre management tools.

3. Complex Operations Management
   - Modern call centre systems are single-vendor, fully-integrated platforms which reduce the complexity for sustainment and enhancements.
   - The current multi-vendor system leads to accountability issues and has resulted in a complex support model where confusion and miscommunication occurs.
4. Limited Capabilities for Agents & Customers
   - Existing Contact Centre functionality and integration capability limit agent's ability to better understand and address customer needs.
   - Limited functionality and reporting capabilities with the current Contact Centre platform.
   - Lack of information exchange among Contact Centres as a result of dispersed technology architecture limits agent's access to caller information across departments.

Discussion of Alternatives:

BC Hydro considered three alternatives:

i. Maintain the current technology solution;

ii. Pursue upgrades using solutions provided by vendors that already have systems deployed in BC Hydro’s environment; and

iii. Replace the current solutions and technology through competitive sourcing.

Alternative iii, Replacement, was chosen because it addresses all the identified issues at the lowest total cost of ownership. Alternative i would require costly infrastructure upgrades to extend life expectancy and maintain system reliability, but would not address issues 3 and 4. Alternative ii would involve implementation of a vendor product without review of competing products from other vendors, would likely not fully address issues 3 and 4, and would likely cost more than Alternative i.

Project Impacts and Benefits:

- Technology obsolescence risk will be mitigated through the implementation of a modern vendor-supported platform.
- Improved system stability and reliability with modern contact centre technology which allows for performance scalability during peak outage events.
- Streamlined operations management and sustainment of the contact centre technology platform.
- Improved functionality and capabilities for the contact centre, including investment options for enhanced self service capabilities that reduce operating costs.

Project Implementation Phase Risk:	Risk Treatment:
This project is not yet in Implementation.	To be determined when the project reaches Implementation.

Additional Information:

BC Hydro expects to file an application under section 44.2 of the *Utilities Commission Act* for this project.

Investment Planning ID: T002549	Project Name: Distribution Design Modernization	
Forecast Capital Cost: $23 million	**Forecast In-Service Date:** Fiscal 2025	**Start Date of Construction:**[1] Fiscal 2023
Development Phase: Planning	**Filing Reference:** New	

Description:

Modernize the distribution design processes through improved software tools for estimation, design, and work order creation. The project will migrate and enhance existing work management capabilities from Passport to SAP, implement new graphical design software and enhance the electrical connection request processes.

Key Drivers:

- Risk reduction
- Increased operational efficiency

Issues Being Addressed:

BC Hydro plans for the following issues to be addressed:

- Distribution Design and Customer Connections work relies on a suite of custom Information technology (**IT**) applications and the Passport Enterprise Resource Planning (**ERP**) platform, considered to be obsolete. This represents an increasing cybersecurity and reliability risk. The technology is functionally limited, imposes a high administrative burden on BC Hydro, and can no longer be cost-effectively improved. Continued use of Passport ERP prolongs and extends unnecessary complexity to BC Hydro's IT landscape; and
- Distribution Design workforce productivity is hampered by separate IT solutions for tabular, graphical and CAD based Design.

Discussion of Alternatives

BC Hydro has identified the following two potential alternatives for evaluation in the Identification phase:

i. Migration from Passport to SAP while keeping DAD as the graphical design tool; and
ii. Migration from Passport to SAP with implementation of modern graphical design tool.

Project Impacts and Benefits:

The following potential benefits may be identified and evaluated in the Identification phase:

- Reduced reliability and cybersecurity risk through eliminated reliance on unsupported software;
- Operating cost savings through improved design and drafting productivity, improved optimization of materials and labour, and improved efficiencies in processing electrical connection requests; and
- Capital cost savings through improved asset sizing and use of materials in designs and by reducing the likelihood of overbuilding distribution equipment.

Project Implementation Phase Risk:	Risk Treatment:
This project is not yet in Implementation.	To be determined when the project reaches Implementation.

Additional Information:

The project's most recent, revised capital cost estimate is $48 million. BC Hydro expects to file an application under section 44.2 of the *Utilities Commission Act* for this project.

1 Start Date of Construction is the Implementation Approval Date.

Investment Planning ID:	Project Name:	
T002036	Energy Management System Upgrade	
Forecast Capital Cost: $ 12.4 million	**Forecast In-Service Date:** Fiscal 2023	**Start Date of Construction:**[1] Fiscal 2021
Development Phase: Definition	**Filing Reference:** F20-F21 RRA: • Exhibit B-29, page 2 F22 RRA: • Application, pages 6-74 • Appendix I, line 7 • BCUC IR 1.50.2	

Description:

The Energy Management System (**EMS**) is a critical engineering system used by Transmission and Distribution System Operations to operate the bulk electric system in the province of B.C. and comply with Mandatory Reliability Standards (**MRS**). The system provides real-time monitoring and control of the power system and is the primary tool for control room operators in the Lower Mainland and the Interior. This project will upgrade BC Hydro's existing EMS software to a newer version, and will also replace the existing, end-of-life EMS technical infrastructure.

Key Drivers:

- Operational Requirements
- Risk reduction

Issues Being Addressed:

In order to maintain EMS reliability and security, and manage risk to the bulk electric system, the EMS software must be upgraded, and EMS technical infrastructure replaced in a timely manner.

BC Hydro generally maintains the EMS software at the latest version and replaces the technical infrastructure approximately every five years. The last major EMS software upgrade and hardware replacement was completed in 2017.

Discussion of Alternatives:

BC Hydro considered five alternatives:

i. **Full Upgrade** of EMS - includes upgrade of both software and hardware infrastructure;

ii. **Status Quo** – continue to use current software and hardware infrastructure with no plans for replacement;

iii. **Defer** – defer the start of the project;

iv. **Upgrade software only** – upgrade the EMS application without upgrading the underlying hardware technology to reduce project costs; and

v. **Upgrade hardware only** – upgrade the EMS hardware only and do not upgrade the application software to reduce project costs.

BC Hydro selected Alternative i, Full Upgrade. Alternatives ii and iii did not address the issues. Alternative iv is not viable due to the incompatibility between the legacy hardware and the new software. The same applies for Alternative v as the legacy software and the newer hardware are incompatible. Upgraded software requires a current hardware format to comply with software specifications.

[1] Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits: • The EMS availability is maintained, and BC Hydro operational requirements are met. • MRS compliance is supported for real-time operations and personnel training, long-term transmission system planning, protection system maintenance programs and critical infrastructure protection. The upgrade will reduce the risk of the following: • Increased cost of technology system repairs due to unplanned technology failures; and • Increased cost to Operations due to failures caused by unplanned technology that impacts the ability to manage the bulk electrical systems.	
Project Implementation Phase Risk: This project is not yet in Implementation.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: The project's most recent, revised capital cost estimate is $26.9 million. BC Hydro expects to file an application under section 44.2 of the *Utilities Commission Act* for this project.	

Investment Planning ID: T002718	Project Name: Enterprise MRS Compliance Management System	
Forecast Capital Cost: $ 2.9 million	**Forecast In-Service Date:** Fiscal 2024	**Start Date of Construction:**[1] Fiscal 2023
Development Phase: Future	**Filing Reference:** New	

Description:

Establish a standard governance and compliance oversight process and expand and improve the existing Compliance Management System software solution to support BC Hydro's continued compliance with Mandatory Reliability Standards (**MRS**). The existing software solution will be enhanced to include 102 adopted MRS within approximately 511 MRS requirements across Operations and Planning (**O&P**) and Critical Infrastructure Protection (**CIP**).

Key Drivers:

- Reliability
- Risk reduction

Issues Being Addressed:

Currently, BC Hydro does not have a standard and uniform compliance process or supporting solution for MRS that encompasses both O&P and CIP standards. The current compliance management system is limited to a selection of CIP standards and requirements. Having a consistent and standard MRS compliance process and a solution that supports this process ensures BC Hydro continues to comply with MRS, reducing reliability, reputation, and financial risks.

The Enterprise MRS Compliance Management System project has been identified as a key enabler for the processes and internal controls referenced within BC Hydro's Internal Compliance Program (**ICP**) to strengthen our compliance objectives. The project will leverage a central compliance system as BC Hydro's single platform for managing compliance workflows.

Discussion of Alternatives:

BC Hydro will identify and evaluate the alternatives in the Identification phase.

Project Impacts and Benefits:

The following potential benefits may be identified for evaluation in the Identification phase:

- Improved MRS compliance by establishing standardized governance, management and control across standards with the objective to increase effectiveness and efficiency of MRS compliance activities;
- Identification and documentation of risks, controls and processes associated with MRS based on Industry best practices and implementation of relevant subset of controls within the compliance management system;
- Improved reporting, dashboarding and competency management and standardization of reports for enterprise-wide use;
- Enhanced asset inventory, configuration, workflow and reporting and monitoring capabilities; and
- Improved and automated evidence collection, self certification and Reliability Standards Audit Worksheet (**RSAW**) generation process with user friendly and easy to use documents packaging capability for data requests.
- Built in security and controls based on roles and responsibilities.

[1] Start Date of Construction is the Implementation Approval Date.

The project will reduce the risk of the following: • Financial penalties brought about by MRS non-compliance. • Electricity reliability impacts to B.C. customers and interconnected utilities.	
Project Implementation Phase Risk: This project is not yet in Implementation.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: A study was conducted from March to May 2021 to assess BC Hydro's existing software's capabilities to support the vision of having a single MRS compliance management system. The results of the study were used as an input to this project and the current, revised estimates indicate a capital cost range of $10 million to $12 million.	

Program of Projects Name: Corporation Telephony Replacement		
Appendix I Reference: Corporate Telephony Replacement		
Investment Planning ID: T002202 T002669	**Project Name:** Corporate Telephony Replacement Project Corporate Telephony Replacement Work Program F23-F25	
Forecast Capital Cost: $6.6 million	**Forecast In-Service Date(s):** Fiscal 2023, 2024, 2025	**Start Date of Construction:**[1] Fiscal 2022
Development Phase: Project in Identification Work Programs in Planning	**Filing Reference:** New	
Description of Program of Projects: Corporate Telephony Replacement is a program of projects to replace the end-of-life corporate telephony system with a fully supported system featuring improved, modern capabilities. The initial project will replace the core telephony system and set the standard for the replacement of telephony at corporate and field offices as well as refresh three sites with the new telephony system. The Corporate Telephony Replacement Work Program F23-F25 will continue the replacement of the current telephony at additional sites. Additional capital expenditure may be required in the fiscal 2026 to fiscal 2028 period to complete replacements of equipment at remaining sites and/or to initiate asset refresh.		
Issues to be addressed: • Obsolete, unreliable and unsupported telephony technologies and infrastructure (licenses, hardware and software). • Limited ability to support new employees and sites. • Complex infrastructure with components from multiple vendors combined together. • Unable to provide modern unified communication capabilities such as integration with Microsoft desktop and collaboration tools. • Unable to provide self-serve capabilities including deskphone password reset and employee onboard/offboard automation.		
Schedule of Program of Projects: • Corporate Telephony Replacement Project (T002202) in service fiscal 2023 • Corporate Telephony Replacement Work Program (T002669) in service fiscal 2023 to fiscal 2025		
Risks and Mitigation Strategies: N/A		
Additional Information: N/A		

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="3">Program of Projects Name: Data Centre Backup</td></tr>
<tr><td colspan="3"></td></tr>
<tr><td colspan="3">Appendix I Reference:
Data Centre Backup</td></tr>
<tr><td>Investment Planning ID:
T001072
T002678
T002679</td><td colspan="2">Project Name:
Data Centre Backup
Data Centre Backup Sustainment Work Program F23
Data Centre Backup Sustainment Work Program F24</td></tr>
<tr><td>Forecast Capital Cost:
$9.0 million</td><td>Forecast In-Service Date:
Fiscal 2023, 2024</td><td>Start Date of Construction:[1]
Fiscal 2023</td></tr>
<tr><td>Development Phase:
Definition (T001072)
Planning (T002678, T002679)</td><td colspan="2">Filing Reference:
New</td></tr>
<tr><td colspan="3"></td></tr>
<tr><td colspan="3">Description of Program of Projects:
The Data Centre Backup project will improve BC Hydro’s data backup systems and technologies to safeguard against data loss. The improved data backup solution will help ensure the protection of BC Hydro's data and provide new capacity for increasing data volumes and sources.</td></tr>
<tr><td colspan="3">Issues to be addressed:
Improve ability to comprehensively manage cybersecurity risk.
Inability to complete backups within required processing duration.
Infrastructure approaching end-of-life and will no longer be fully vendor supported starting in fiscal 2023.
Excessive system complexity with over 20 backup methods.
Inability to scale to meet data growth and support advanced data sources.
Lack of reporting.</td></tr>
<tr><td colspan="3">Schedule of Program of Projects:
Data Centre Backup (T001072) in service fiscal 2023
Data Centre Backup Sustainment Work Program F23 (T002378) in service fiscal 2023
Data Centre Backup Sustainment Work Program F24 (T002379) in service fiscal 2024</td></tr>
<tr><td colspan="3">Risks and Mitigation Strategies:
N/A</td></tr>
<tr><td colspan="3">Additional Information:
N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID:	Project Name:	
T001379	SAP S/4HANA Upgrade	
Forecast Capital Cost: $ 22.5 million	**Forecast In-Service Date:** Fiscal 2027	**Start Date of Construction:**[1] To be determined
Development Phase: Planning	**Filing Reference:** F20-F21 RRA: • Application, pages 6-153 • Appendix I - Technology, line 9 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • BCUC IR 1.50.2	

Description:

Upgrade and migrate BC Hydro's primary Enterprise Resource Planning (**ERP**) system and solutions from our current SAP product version to SAP S/4HANA[2] in alignment with SAP's product roadmap and BC Hydro's Technology ERP roadmap. This is to ensure the long-term availability of SAP product support and innovation to avoid IT obsolescence and associated business risks.

Key Drivers:

- Reliability
- Risk reduction

Issues Being Addressed:

Operating an unsupported version of our primary ERP system represents an unacceptable reliability and cybersecurity risk. Mainstream vendor support for BC Hydro's SAP version ends in 2027.

Discussion of Alternatives:

BC Hydro uses SAP software to enable key business functions, including Finance, Human Resources, Customer Care & Billing, Environmental / Health / Safety Management, Project & Portfolio Management, Supply Chain, Enterprise Asset Management and Work Management.

BC Hydro is committed to a single ERP system strategy with regular product updates to avoid product obsolescence and appropriately balance asset performance, cost and risk. The importance of the SAP software, the need for continuity of vendor support, and the expected three-year project duration make it imperative for BC Hydro to start the project by fiscal 2025.

Project Impacts and Benefits:

The project will avoid ERP system obsolescence through the long-term continuity of access to SAP's products, support and innovation. Benefits will be identified and assessed during the Identification phase.

Project Implementation Phase Risk:	Risk Treatment:
This project is not yet in Implementation.	To be determined prior to Implementation phase.

Additional Information:

BC Hydro expects to file an application under section 44.2 of the *Utilities Commission Act* for this project.

1 Start Date of Construction is the Implementation Approval Date.
2 S/4HANA is SAP's current generation of its core ERP application.

Investment Planning ID: T002122	**Project Name:** Stations Work Management	
Forecast Capital Cost: $ 22 million	**Forecast In-Service Date:** Fiscal 2023	**Start Date of Construction:**[1] To be determined
Development Phase: Planning	**Filing Reference:** New	

Description:

Mitigate work management issues and risks in Stations Field Operations by addressing IT obsolescence. Stations work records will be migrated out of Passport and into SAP, and an enterprise grade work planning and scheduling tool will be implemented to replace the existing spreadsheet solution. These changes will facilitate the decommissioning of Passport, improve maintenance productivity and streamline work processes.

Key Drivers:

- Risk reduction
- Increased operational efficiency

Issues Being Addressed:

A range of Stations work management issues are being caused, worsened, or prolonged by the obsolescence of the current work management core system, Passport, and the spreadsheet-based planning and scheduling solution.

Discussion of Alternatives:

BC Hydro will identify and assess alternatives during the Identification phase

Project Impacts and Benefits:

Benefits will be identified during the Identification phase.

Project Implementation Phase Risk:	**Risk Treatment:**
To be assessed prior to Implementation phase.	To be determined prior to Implementation phase.

Additional Information:

BC Hydro expects to file an application under section 44.2 of the *Utilities Commission Act* for this project.

1 Start Date of Construction is the Implementation Approval Date.

Investment Planning ID:	Project Name:	
P201703	Chilliwack Field Building Redevelopment	
Forecast Capital Cost: $36.0 million	**Forecast In-Service Date:** Fiscal 2026	**Start Date of Construction:**[1] Fiscal 2023
Development Phase: Definition	**Filing Reference:** F17-F19 RRA: • Appendix I, line 15, Appendix J, pages 84-85 • BCUC IRs 1.70.3, 1.116.1, 1.116.2, 1.116.3, 1.116.4, 1.116.5, 2.249.8, 2.260.4, 2.270.1, BCOAPO IRs 1.36.1, 2.77.1 F20-F21 RRA: • Chapter 6, pages 6-162 • Appendix I - Properties, line 4, Appendix J, page 123 • BCUC IR 1.133.1 Confidential • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-80 • Appendix I - Properties, line 2	

Description:

This project involves the redevelopment of a district field building located in Chilliwack.

BC Hydro operations are based out of two locations in Chilliwack, one of which is located within the Atchelitz substation property at 6155 Lickman Road and the other which is a leased property within a multi-tenanted facility, consisting of approximately 12,000 ft^2 of office and warehouse space at 44550 South Sumas Road. The Atchelitz facility is owned by BC Hydro and was built approximately 40 years ago, and comprises about 5,500 ft^2 of office space. A total of approximately 35 staff are based at these two sites.

There is a long-term need for a suitable field office to provide operational and post-disaster recovery and emergency support to meet the needs of the almost 100,000 residents served in Chilliwack and the surrounding areas of Atchelitz, Cultus Lake, Sardis, Promontory Heights, Vedder, Yarrow, and Greendale. This includes appropriate outage response, planning and execution of the electric system to support local/regional development, and maintenance and upgrades to infrastructure to ensure ongoing system reliability in the region. In order to “keep the lights on”, the facilities must remain operational to support 24/7 emergency response in the worst weather conditions and in the event of a natural disaster.

Key Drivers:

- Operational Requirements
- Safety
- Reliability

Issues Being Addressed:

The existing facilities have been prioritized for redevelopment due to the following: lack of adequate space for current and projected business operations; the inability to expand either the Chilliwack facility (it is a leased building) and the Atchelitz location (close proximity to a substation); and the condition and associated seismic concerns of the existing buildings. The key issues are:

1 Start Date of Construction is the Implementation Approval Date.

- The facilities have inadequate space for existing staff and materials, requiring some staff to work out of the Abbotsford facility, approximately 35 km away, and requiring the Abbotsford office to store a large volume of materials, including poles and transformers, for the Chilliwack/Atchelitz operations. This can delay response time, especially in the winter or during emergencies;
- The facilities are inadequate for working, maneuvering and loading line trucks. The location of the Atchelitz office on the same site as a substation prevents office expansion and puts a strain on the safe and efficient use of yard space. It is also difficult to safely move and load line vehicles in the multi-tenanted Chilliwack office complex;
- Both facilities are located in a high seismic region and do not meet requirements for a facility that is expected to be fully functional in a post-disaster situation;
- The facilities have inadequate fire suppression and sprinklers, contain hazardous materials, lack an emergency generator, and require the replacement of the Atchelitz end of life roof; and
- The facilities have inadequate office space to support the current and future demands.

Discussion of Alternatives:

The six alternatives being considered include:

i. **Do nothing:** continue with existing facilities;
ii. **Lease** additional space adjacent to the existing Chilliwack facility;
iii. **Renovate and expand** the existing Atchelitz facility, or build new, and maintain the leased Chilliwack facility;
iv. **Construct** a new facility at a BC Hydro owned location;
v. **Acquire** a new site and construct a new facility; and
vi. **Lease** a larger facility, long-term.

Alternative iv, Construct a new facility at a BC Hydro owned location, has been selected as the preferred alternative as it meets the current and future needs for servicing the Chilliwack Region. In the previous Appendix J for this project in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application, Alternative v was the recommended alternative but we were unable to acquire a suitable property. As a result, an owned property has been revisited and a design developed for a modified facility to work within the constraints of the site.

Alternative i was not selected as it did not address safety issues and space constraints. Alternative ii was not selected as there was no space available that met the specific requirements for office, warehouse, yard and parking. Alternative iii was not selected as the site was too small for the required operations. Alternative vi was not selected as there was no available leased land that met the operational requirements.

Project Impacts and Benefits:

- Project will result in a new facility that meets current and anticipated functional and operational needs.
- The new facility will meet all current building codes including post-disaster standards.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks will be identified starting in the Identification Phase and finalized in the Implementation Phase	To be determined when the project reaches implementation

Additional Information:

N/A

<table>
<tr><td>Investment Planning ID:
P201704</td><td colspan="2">Project Name:
Material Classification Facility Building Redevelopment</td></tr>
<tr><td>Forecast Capital Cost:
$46.9 million</td><td>Forecast In-Service Date:
Fiscal 2024</td><td>Start Date of Construction:[1]
Fiscal 2021</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I, line 11
• Appendix J, pages 82-83
• BCUC IR 1.117.2, 1.117.3, 1.117.4, 1.117.4, 1.117.5, 1.117.6
F20-F21 RRA:
• Chapter 6, pages 6-162
• Appendix I - Properties, line 5, Appendix J, page 125
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Chapter 6, page 6-80
• Appendix I - Properties, line 1</td></tr>
</table>

Description:

This project involves the redevelopment of the Material Classification Facility in Surrey. The Material Classification Facility is located at 12345 88th Avenue in Surrey, B.C. on the BC Hydro Surrey campus. The facility comprises the Transformer Shop and Hazardous Waste Operations including salvage and disposal operations and occupies an area of 19,800 sq.ft. of building area and 8.6 acres of yard space. The buildings were constructed throughout the 1970's and 1980's as business needs required. Approximately 27 employees work out of this facility.

The facility receives recovered electrical equipment and hazardous wastes from BC Hydro's operations from across the entire province, making it critical in supporting other business units' waste needs. The products are received, drained of any oils, sorted, stored, and packaged or re-packaged prior to being transported offsite for recycling, treatment, or disposal at authorized hazardous waste management facilities.

Key Drivers:

- Environmental
- Operational Requirements
- Safety

Issues Being Addressed:

The Material Classification Facility has been identified as a priority for redevelopment due to environmental regulation requirements, zoning non-compliance, operational challenges, building conditions, and code compliance.

The key issues are that the facilities:

- Do not meet the Ministry of Environment's protection measures that prevent the release of contaminants of concern and prevent pollution;
- Contravene existing zoning regulations from the City of Surrey;
- Do not provide sufficient enclosed areas to sort and store materials;

[1] Start Date of Construction is the Implementation Approval Date.

- Cannot support current business requirements of oil storage and Paper Insulated Lead Covered cable sampling;
- Do not meet current building code standards, including meeting less than 50 per cent of the BC Building Code minimum requirements for normal buildings being able to withstand a seismic event; and
- Have numerous building components (building envelope, mechanical and electrical systems) at the end of their useful life and needing replacement.

Discussion of Alternatives:

BC Hydro evaluated the following five alternatives:

i. **Do nothing:** continue with existing facilities;

ii. **Apply for rezoning and, if approved, renovate** and expand the existing facilities to meet current building code, safety and program requirements;

iii. **Apply for rezoning and, if approved, construct** a new facility on the existing site and demolish the existing building;

iv. **Construct** a new facility at a new location on Surrey campus; and

v. **Acquire** a new site off the Surrey campus and construct a new facility.

Alternative iv, Construct a new facility at a new location on Surrey campus, was selected as the recommended alternative as it is the most cost effective alternative as it utilizes property BC Hydro owns, reduces maintenance costs for aged facilities, and meets the environmental, operational and zoning requirements. Alternative i was not selected due to non-compliance with Ministry of Environment guidelines for storage and contaminated materials as well as zoning non-compliance. Alternatives ii and iii were not selected as applications for re-zoning are lengthy and approval is not guaranteed. Alternative v was not selected as the project team was unable to find a suitable site with the appropriate zoning and size.

Project Impacts and Benefits:

- New facility that is compliant with Ministry of Environment's Hazardous Waste Regulations
- New facility being compliant with City of Surrey zoning regulations.
- New facility that meets operational needs and current building codes including seismic withstand.

Project Implementation Phase Risk:	**Risk Treatment:**
Impact to schedule due to delays in procurement for major equipment.	Expected equipment lead times and shop drawing approval times have been factored into the project schedule. In addition, target delivery dates have been included in the tender documents.
Potential for unforeseen cost increases during construction.	A construction contingency has been applied for unforeseen items, such as increasing commodity costs during construction. Early procurement of high value, high risk work packages to reduce the risk of price escalations.

Additional Information:

N/A

Investment Planning ID: P201901	**Project Name:** Kamloops Field Building Redevelopment	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Identification	**Filing Reference:** F20-F21 RRA: • Chapter 6, pages 6-162 • Appendix I - Properties, line 6, Appendix J, page 127 • BCOAPO IR 1.62.1 PUBLIC Attachment 1 F22 RRA: • Chapter 6, page 6-80 • Appendix I - Properties, line 4	

Description:

This project involves the redevelopment of the large district field office located in Kamloops.

The Kamloops District Office is located at 1155 McGill Road in Kamloops and was constructed in 1981. The District Office is approximately 34,000 ft2 in size and serves BC Hydro customers in Kamloops and the surrounding areas. The facility currently accommodates approximately 130 staff.

There is a long-term need for a suitable field office to provide operational and post disaster recovery and emergency support, and to meet the needs of more than 100,000 customers in the surrounding area that spans east to Chase, west to Savona, north to Barierre, and south to Lac Le Jeune. This support includes outage response, planning and execution of the electric system to support local/regional development, and maintenance and upgrades to infrastructure to ensure ongoing system reliability in the region. In order to “keep the lights on”, the facilities must remain operational to support 24/7 emergency response in the worst weather conditions and in the event of a natural disaster.

Key Drivers:

- Operational Requirements
- Safety

Issues Being Addressed:

The existing facility has been prioritized for redevelopment due to a lack of adequate space for current and projected business operations, requirement for seismic and safety upgrades, and to address building condition, and code compliance. The key issues are that the facility:

- Does not meet current functional and operational needs, or future growth. The facility does not provide sufficient space to accommodate all current staff, does not provide adequate truck bays for truck storage or for Fleet’s current needs, and does not provide sufficient yard space for vehicles and materials;
- Is almost 40 years old, and does not meet current building code standards, including meeting less than 50 per cent of the BC Building Code minimum requirements for a post disaster resistance building;
- Has inadequate fire protection and accessibility, including non-conforming fire separation between the garage and offices; and
- Has numerous building components (mechanical, electrical, HVAC, interiors) requiring replacement.

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives: BC Hydro is considering four alternatives: **i.** **Do nothing** and continue to budget for major maintenance and replacements**;** **ii.** **Renovate and expand** the existing facility; **iii.** **Construct** a new facility on the existing site, and iv. **Build** a new facility on a new purchased or leased site.	
Project Impacts and Benefits: To be determined when project reaches Definition phase	
Project Implementation Phase Risk: Risks will be identified starting in the Identification Phase and finalized in the Implementation Phase	**Risk Treatment:** To be determined when the project reaches implementation
Additional Information: N/A	

Investment Planning ID: P201902	Project Name: North Vancouver Field Building Redevelopment	
Forecast Capital Cost: $43.0 million	**Forecast In-Service Date:** Fiscal 2026	**Start Date of Construction:**[1] Fiscal 2023
Development Phase: Definition	**Filing Reference:** F22 RRA: • Chapter 6, page 6-80 • Appendix I - Properties, line 6	

Description:

This project involves the redevelopment of a district field office located in North Vancouver. The existing North Vancouver District Office facility is located at 630 Brooksbank Avenue. The existing facility is a two-storey steel frame building that was constructed in 1985. The main building has a total area of 26,000 sq.ft. Indoor accommodations are categorized as administrative, industrial, and base building components. The facility currently accommodates 67 staff.

There is a long-term need for a suitable field office to provide operational and post disaster recovery and emergency support and to meet the needs of approximately 182,000 customers within North Vancouver, West Vancouver, Lions Bay and Bowen Island. This support includes outage response, planning and execution of the electric system to support local/regional development, and maintenance and upgrades to infrastructure to ensure ongoing system reliability in the region. The facility must remain operational to support 24/7 emergency response in the worst weather conditions and in the event of a natural disaster. Additionally, in the event of an emergency where the Lions Gate and Iron Workers bridges are compromised, BC Hydro's disaster response plan will be compromised for the North Shore operational area and the greater Sea to Sky corridor, unless this North Vancouver District Office is fully operational.

Key Drivers:

- Operational Requirements
- Safety

Issues Being Addressed:

The existing facilities have been prioritized for redevelopment due to the following issues:

- Lack of adequate space for current and projected business operations
- Need for additional truck bays, and right-sizing of existing truck bays;
- Lack of storage space, and workshop space;
- Non-compliance with the current Building Code; and
- Emergency response and system restoration for the North Shore operational area and the greater Sea to Sky corridor.

Discussion of Alternatives:

The following four alternatives were considered in the Identification phase.

i. **Status Quo:** Continue to maintain and repair the existing facility and plan for increased maintenance costs;

ii. **Renovate and Expand** the existing facility

iii. **Construct** a new facility on the existing site; and

iv. **Construct** a new facility on a new site.

Alternative iii, Construct a new building on existing site, was selected as the preferred alternative as it addresses the safety concerns associated with the current facility, ensures operational business

[1] Start Date of Construction is the Implementation Approval Date.

continuity in the event of an emergency and addresses operational deficiencies. Utilizing our existing property prevents a challenging search for low cost land in the area. Alternative i was not selected due to lack of seismic resistance that could negatively impact business continuity, safety and space constraints for operations. Alternative ii was not selected as renovating the existing facility, adding an expansion and parking would not fit on the two acre site. Alternative iv was not selected as there was no viable industrial property available in close proximity to the customer base and thoroughfares.
Project Impacts and Benefits: • Facility that meets current and anticipated functional and operational needs • Facility that meets all current Building Code standards including safety and post-disaster withstand.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation

Additional Information: N/A

Investment Planning ID:	Project Name:	
P202202	Campbell River II Field Building Redevelopment	
Forecast Capital Cost: $43.0 million	**Forecast In-Service Date:** Fiscal 2026	**Start Date of Construction:**[1] Fiscal 2023
Development Phase: Definition	**Filing Reference:** New	

Description:

This project involves the redevelopment of a district field office facility in Campbell River.

The existing Ironwood facility is a leased property located at 1280/1400 Ironwood Street, within the Ironwood Mall in Campbell River. The current single-story lease is comprised of 9,000 sq. ft. of office space, 10,000 sq. ft. of storage space, yard, and parking.

The existing John Hart Administration building, located at 10 John Hart Road, was constructed in 1991. It is a two-story pre-engineered building with a wood framed entry administration space. The overall floor area is 8,000 sq. ft. The two facilities currently accommodate approximately 100 staff combined, who provide service to six Generation stations and associated dams, canals, and spillways, as well as provide service to 23 substations.

The purpose of the Campbell River Phase II project is to provide a new and permanent office location for the 100 staff currently located at the Ironwood Facility and the John Hart Administration building and consolidate all operations in the Campbell River area on one location at the existing Campbell River I office facility, which is located on land leased under a long term agreement with a local First Nation.

Key Drivers:

- Operational Requirements
- Safety
- Reliability

Issues Being Addressed:

The existing BC Hydro facilities at Ironwood and John Hart are not meeting the current operational needs of the business. The key issues are that the facilities:

- Do not meet operational needs as the office is located in a retail space, there is insufficient yard space and minimal parking for trucks;
- Do not meet current Building Code, including seismic withstand requirements; and
- Are geographically separated with staff in three facilities within the Campbell River area.

Discussion of Alternatives:

BC Hydro evaluated the following four alternatives:

i. **Do nothing:** Continue to maintain and repair the existing facilities at Ironwood and John Hart facilities, and plan for increased maintenance and asset replacement costs moving forward;

ii. **Expansion on existing Campbell River I site:** new build and parking on the existing BC Hydro leased field office site;

iii. **Expansion on existing Campbell River I site and adjacent site:** lease adjacent site and construct new building, parking and operations yard; and

iv. **Renovate and expand John Hart Facility:** Renovate and expand the existing John Hart Admin facility.

1 Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">Alternative iii, Expansion on existing Campbell River site and adjacent site, was selected as the recommended alternative as it will avoid long-term lease costs and utilize space originally built in the Campbell River I office facility for future staff. In addition, it will achieve the primary goal to consolidate the three facilities and create an effective solution for staff and operations. Alternative i was not selected as it did not address building code compliance and seismic issues and there was inadequate space for operations. Alternative ii was not selected as the site was not large enough to accommodate the space requirements of the three facilities. Alternative iv was not selected as it was an unsuitable location on a flood plain and could not accommodate the primary goal of consolidating three facilities in one location.</td></tr>
<tr><td colspan="2">Project Impacts and Benefits:
• Project will result in a new facility that meets current and anticipated functional and operational needs.
• The new facility will meet all current building codes including post-disaster standards.</td></tr>
<tr><td>Project Implementation Phase Risk:
Risks will be identified starting in the Identification Phase and finalized in the Implementation Phase</td><td>Risk Treatment:
To be determined when the project reaches implementation</td></tr>
<tr><td colspan="2">Additional Information:
N/A</td></tr>
</table>

Investment Planning ID: P202101	Project Name: Duncan Field Building Redevelopment	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Future	**Filing Reference:** F22 RRA: • Chapter 6, page 6-80 • Appendix I - Properties, line 5	

Description:

This project involves the redevelopment of a district field office facility in Duncan. The Duncan Field Office facility is located at 6494 Norcross Road, Duncan, on Vancouver Island. Originally constructed in mid-1970s as a car dealership, the building and grounds were converted into a BC Hydro district office in 1980. The current office and warehouse facility occupy approximately 9,000 sq. ft. on a two-acre site, and has 20 staff based at this location.

There is a long-term need for a suitable field office to provide operational and post disaster recovery and emergency support and to meet the needs of approximately 80,000 customers within the Cowichan Valley Regional District. This support includes outage response, planning and execution of the electric system to support local/regional development, and maintenance and upgrades to infrastructure to ensure ongoing system reliability in the region. The facility must remain operational to support 24/7 emergency response in the worst weather conditions and in the event of a natural disaster.

Key Drivers:

- Operational Requirements
- Safety
- Reliability

Issues Being Addressed:

The existing facility has been prioritized for re-development due to the following issues:

- The facility meets less than 50 per cent seismic resistance capacity per current Building Code and is located in the highest seismic vulnerability region in Canada;
- Numerous Building Code non-compliance issues including inadequate fire safety and accessibility;
- A highly constrained yard – inadequate size, insufficient line-truck turning radius, steep slopes, resulting in unsafe yard and traffic flow conditions;
- Many of the original building components are in poor condition and now at or near end-of-life
- The truck bays are too small to service the larger line trucks; and
- Current building size is too small for users' needs and cannot be reconfigured to meet operational requirements.

Discussion of Alternatives:

BC Hydro is considering four alternatives:

i. **Do nothing:** continue to maintain and replace components at high cost;

ii. **Renovate and expand the existing facility**;

iii. **Construct a new facility on the existing site**; and

iv. **Construct a new facility on a new site**.

[1] Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits:	
To be determined when project reaches Definition phase.	
Project Implementation Phase Risk:	**Risk Treatment:**
Risks will be identified starting in the Identification Phase and finalized in the Implementation Phase	To be determined when the project reaches implementation
Additional Information:	
$5 million has been included in the fiscal 2023 of the F22-F31 Capital Plan for land purchase as the existing site is too small for redevelopment.	

Investment Planning ID:	Project Name:	
P202202	Cranbrook Field Building Redevelopment	
Forecast Capital Cost: To be determined	**Forecast In-Service Date:** To be determined	**Start Date of Construction:**[1] To be determined
Development Phase: Identification	**Filing Reference:** New	

Description:

This project involves the redevelopment of a district field office facility in Cranbrook. The Cranbrook Field Office is located at 629 Industrial Road No. 2. It was originally constructed in 1972. The 25,000 sq. ft main building includes offices, workshops, truck storage, and warehouses. A total of 61 employees are based at the facility.

Key Drivers:

- Operational Requirements
- Safety
- Reliability

Issues Being Addressed:

There is a long-term need for a suitable field office to provide operational and post disaster recovery and emergency support to meet the needs of approximately 40,000 customers in the East Kootenay Region including the City of Cranbrook and City of Kimberley. This includes appropriate outage response, planning and execution of the electric system to support local/regional development, and maintenance and upgrades to infrastructure to ensure ongoing system reliability in the region. The Cranbrook Field Office is a critical service provider of operations and maintenance of the power grid system and must remain operational to support 24/7/365 emergency response in all weather and natural disaster conditions to “keep the lights on” and support residential, commercial and industrial customers.

The existing facility has been prioritized for redevelopment due to a lack of adequate space for current and projected business operations, requirements for seismic and safety upgrades, and to address building condition and code compliance. The key issues are that:

- The facility is in a high seismic region and does not meet requirements to be fully functional in a post-disaster situation;
- The roof does not meet the current snow load requirements and snow removal is required to provide safety and business continuity;
- The roof does not meet the current snow load requirements, which presents a safety issue to the occupants inside the building and a risk to business continuity;
- There is a lack of adequate fire suppression and sprinklers;
- Space constraints associated with the building, truck storage and yard, which need to be addressed to ensure safety and efficiency of operations, and business continuity; and
- The building contains identified encapsulated hazardous material that can pose a safety risk to occupants if disturbed.

---

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives: BC Hydro is considering four alternatives: i. **Do nothing:** continue to maintain and replace components at high cost; ii. **Renovate and expand** the existing facility; iii. **Construct** a new facility on the existing site; and iv. **Construct** a new facility on a new site.	
Project Impacts and Benefits: To be determined when project reaches Definition phase.	
Project Implementation Phase Risk: Risks will be identified starting in the Identification Phase and finalized in the Implementation Phase	**Risk Treatment:** To be determined when the project reaches implementation
Additional Information: N/A	

<table>
<tr><td>Investment Planning ID:
1115778</td><td colspan="2">Project Name:
Site C Project</td></tr>
<tr><td>Forecast Capital Cost:
$16 billion</td><td>Forecast In-Service Date:
November 2025</td><td>Start Date of Construction:[1]
July 2015</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
F20-F21 RRA:
• Appendix I, Site C - line 15, Appendix J, page 129
• BCUC IR 1.133.1 Confidential
• BCOAPO IR 1.62.1 PUBLIC Attachment 1
F22 RRA:
• Appendix I, Site C - line 1
• Appendix Q, page 8 and 24</td></tr>
</table>

Description:

Site C will be a third dam and hydroelectric generating station on the Peace River approximately 7 kilometres southwest of Fort St. John. It will be capable of producing approximately 5,100 gigawatt-hours of electricity annually and 1,100 megawatts of capacity.

Project components include:

- Access roads and a temporary construction access bridge across the river at the dam site;
- A worker accommodation camp at the dam site;
- Upgrades to roads and realignment of segments of Highway 29;
- Two new 500 kV transmission lines connecting Site C to the existing Peace Canyon Substation, along an existing right-of-way;
- Shoreline protection at Hudson's Hope;
- An 800-metre roller-compacted concrete buttress to improve foundation stability and seismic protection;
- An earthfill dam, approximately 1,050 metres long and 60 metres high above the riverbed;
- A generating station with six 183 MW generating units, and spillways; and
- An 83-kilometre-long reservoir that would be, on average, two to three times the width of the current river.

As announced in February 2021 and approved in June 2021, the cost of the Site C project has been revised and is $16 billion, with a one year delay to 2025 for the project in-service date. This updated budget includes capital costs, charges subject to regulatory deferral and certain operating expenditures.

Key Drivers:

- Generation Growth

Issues Being Addressed:

As the third project on one river system, Site C will gain significant efficiencies by taking advantage of water already stored in the Williston Reservoir. This means that Site C will generate approximately 35 per cent of the energy produced at W.A.C. Bennett Dam, with only 5 per cent of the reservoir area.

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives:

Site C has been compared to alternatives in multiple BC Hydro and BCUC processes.

The decision to proceed with Site C was based on the 2013 IRP, which showed that Site C would provide substantial benefits compared to alternative portfolios of clean resources which could include wind, solar, or energy efficiency measures.

A comparison of Site C to alternatives was also done in the 2017 BCUC Inquiry, once again reviewing Site C compared to a range of clean alternative resources. This analysis showed that over 70 years, completing Site C is significantly less expensive than an Alternative Clean Portfolio.

Project Impacts and Benefits:

Project Benefits

Site C is part of the existing and committed resources under BC Hydro's Draft 2021 Integrated Resource Plan. In addition to providing energy, capacity, and flexibility, the Site C Project is providing key benefits for B.C. including regional economic development, job creation, and benefits for communities and Indigenous groups.

Project Attributes

- Site C will provide 1,100 megawatts of capacity, and produce about 5,100 gigawatt hours of electricity each year – enough energy to power the equivalent of about 450,000 homes per year in B.C.
- It will be a source of clean and renewable electricity for more than 100 years.
- Site C will have among the lowest GHG emissions, per gigawatt hour, compared to other resource options.
- As the third project on the Peace River, Site C will rely on the existing Williston Reservoir for water storage. This means Site C will generate approximately 35 per cent of the energy produced at the W.A.C. Bennett Dam, with only 5 per cent of the reservoir area.
- Site C will employ approximately 4,500 workers and create approximately 19,000 person-years of direct employment during construction.
- Construction provides significant opportunities for businesses of all sizes.
- Provides employment, training and contracting opportunities for Indigenous communities
- Once in operation, Site C will result in $2 million in revenue from grants-in-lieu and school taxes.
- Site C will be a source of affordable power to meet B.C.'s future electricity needs.

Environmental Assessment Process

The Site C Project received environmental approval from the federal and provincial governments in October 2014. The approval of the project followed a cooperative federal-provincial environmental assessment process by the Canadian Environmental Assessment Agency (**CEA Agency**) and the British Columbia Environmental Assessment Office (**BCEAO**). The process started in August 2011 and took approximately three years to complete.

The environmental assessment process for Site C was thorough and independent and included multiple opportunities for timely and meaningful participation by the public, Indigenous groups, all levels of government, and other interested stakeholders.

As part of the environmental assessment, BC Hydro undertook multi-year studies to identify and assess potential project effects and proposed comprehensive mitigation measures. All of this information was documented in more than 29,000 pages in the Site C Environmental Impact Statement (EIS) and associated documentation. The extensive review process included two months of public hearings in several regional and Indigenous communities under an independent Joint Review Panel.

Community Benefits and Mitigation Measures

To date, BC Hydro has reached a regional legacy benefits agreement with the Peace River Regional District and community agreements with:

- District of Chetwynd;
- District of Taylor;
- City of Fort St. John; and
- District of Hudson's Hope.

Among the benefits to local communities from the Site C Project are a regional legacy benefits agreement, infrastructure improvements, recreation and tourism opportunities, and affordable housing.

Additional Information:

Risk Description	Impact and Response Plan Summary
Risk that COVID-19 event impacts continuation of construction activities at site or in Vancouver.	**Impact:** BC Hydro and contractors do not have access to the required labour for daily construction and project management activities. BC Hydro and contractor costs increase to respond to COVID-19 and schedule delay impacts; camp capacity reduction and/or shutdown due to COVID-19 outbreaks. **Response:** Minimize non-essential travel to site. Screen workers before they travel to site and at site before entry; implement camp mitigation measures (additional cleaning, closed cafeteria self serve stations, establish isolation wings); put in place BC Hydro and contractor worker protection exposure protocols and plans.
Risk that the Project cannot attract and retain sufficient skilled workers.	**Impact:** Contractors may not be able to adequately source, supply, attract, and retain sufficient project labour due to workforce demographics, increased competition for labour from other major projects, the requirement for specialized workers, and the effects of COVID-19. This may result in potential impacts to schedule, safety, productivity and cost. **Response:** Contractors provide labour sourcing and supply plans, provide advance notice of foreign workers, and participate in local job fairs. BC Hydro encourages and facilitates capacity building initiatives and monitors employee turnover rates and labour conditions on other projects.
Risk that increased interest rates and changes in expenditure timing increases borrowing costs.	**Impact:** Rising interest rates and changes in expenditure timing result in an increase to the Project's interest costs above the amount budgeted. **Response:** Implement interest rate hedging program for future debt placements to reduce the potential impact of rising interest rates. Monitor changes to expenditure timing.
Risk of contractor claims.	**Impact:** Increased construction management and contract management effort required to respond and investigate claims; settlement of claims may result in increased costs. **Response:** Ensure sufficient commercial management resources in place, proactively resolve claims as received, and ensure commercial management procedures are in place.
Risk of a safety incident resulting in a fatality or disabling injury.	**Impact:** Serious worker injury or fatality; project delays and associated costs. **Response:** Continue with BC Hydro and contractor safety steering committee to address shared safety issues and opportunities; BC Hydro and contractors have implemented safety cultural leadership training; increase BC Hydro executive involvement and engagement with site safety leadership; regularly hold on site safety conferences; continue to include safety in BC Hydro and contractor on boarding orientations; and continue to promote a strong safety culture.

Risk Description	Impact and Response Plan Summary
Risk of earthfill dam construction delays due to instrumentation installations.	**Impact:** Earthfill dam construction is delayed awaiting the installation of instruments; Instruments are non-functional and/or damaged. **Response:** Close oversight of the main civil works contractor's current effort to self perform work; main civil works contractor refining/training personnel and drilling techniques/equipment; communicating to main civil works contractor the importance of instrumentation and scheduling to mitigate delays.
Risk of a slope failure on transmission right-of-way above the Site C substation.	**Impact:** Slope failure on the transmission line right-of-way above the substation. Costs to repair transmission lines and substation. **Response:** Conduct geotechnical investigations, install additional instrumentation, and implement agreed upon slope failure mitigation measures prepare by an independent engineering firm.
Risk of erosion of the outlet riprap material.	**Impact:** Cost of remediation; schedule delay and potential generation flow restriction on G.M. Shrum and Peace Canyon generation stations. **Response:** Complete both temporary and permanent solutions to prevent erosion. Monitor outlet area for any signs of erosion.
Risk of procurement uncertainty for the right bank foundation enhancement work.	**Impact:** Existing contractors' scope of work and schedule impacted by potential new right bank foundation enhancement contractor interfaces. **Response:** Rely on change schedule terms of existing contracts to proceed with change orders for the right bank foundation enhancement work scope, and if agreement can't be reached, proceed with an open procurement process.
Risk of lack of access to intake deck impacts transmission lines from generating station to substation.	**Impact:** Delays to transmission lines in-service date and turbine-generator unit 1 in-service date **Response**: Work with interface management and construction management to update the schedule to ensure the transmission lines are available when required. Develop plan to complete the work and resolve any potential lack of access to the intake deck.

BC Hydro
Power smart

Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix K

Capital Project Strategies, Plans and Studies

Table of Contents

1 Introduction

BC Hydro's strategies, plans and studies are developed to seek potential solutions to upgrade the Power System and related infrastructure and do not in themselves create a financial commitment. These strategies, plans and studies investigate and/or recommend broader regional, system, or business solutions or policies, supporting the need or justification for a future project or solution. This appendix includes summaries of Power System strategies, plans or studies that are linked to specific projects included in Appendix I.[1,2]

This appendix is organized as follows:

- Section 2 provides an overview of the current state of BC Hydro's Power System;
- Section 3 explains BC Hydro's strategic planning process and the types of documents that are included in this appendix; and
- Attachment 1 provides summaries of 62 Power System strategies, plans and studies.

2 BC Hydro's Power System

2.1 Overall System

As described in Chapter 6, BC Hydro's generation, transmission and distribution systems form the Power System, generating electricity and delivering it to our customers throughout B.C.

[1] A Technology Strategy and Five-Year Plan is included as Appendix O. Specific strategies are not developed for the Properties, Fleet or Business Support/Other asset categories.

[2] Where applicable, the strategy, plan or study linked to a specific project has been identified in column Y of Appendix I.

Through BC Hydro’s capital investments over the last decade, reliability has been maintained, system capacity has been increased, the effective life of numerous critical assets in the system has improved and many of the most critical Dam Safety risks have been mitigated. BC Hydro continues to provide reliable, affordable, clean electricity throughout B.C. as a result of our asset management and capital investment strategies. As shown in Chapter 6, section 6.3.1, BC Hydro’s customer reliability, as measured by two industry-standard metrics, System Average Interruption Duration Index (**SAIDI**) and System Average Interruption Frequency Index (**SAIFI**), has performed consistently and BC Hydro’s Customer Satisfaction Index indicates that customers continue to be satisfied with the level of reliability they are receiving.

Over time, the condition and performance of existing assets degrade, regulatory and safety requirements change, and new assets are required to address load growth and connect new customers. Together, these factors create new issues, risks and opportunities to be addressed through continued maintenance and capital investment.

The following sections provide an overview of the current state of BC Hydro’s Power System, with remaining issues, risks and opportunities highlighted. More detailed descriptions of the risks, issues and opportunities are discussed through the summaries of strategies, plans or studies in Attachment 1 of this appendix.

2.2 The Generation System

BC Hydro’s generation assets include 83 generating units at 30 hydroelectric generating facilities as well as 85 dams located at generating stations and at additional locations to provide water storage and water diversion functions. Generation assets also include four gas-fired units at BC Hydro’s two thermal generating facilities and four synchronous condenser units at a dedicated synchronous condenser facility. The generating facilities are categorized as “Key”, "Strategic" or "Available" according to the significance of the facility to BC Hydro's system. BC Hydro has adopted life cycle asset management practices as its approach to managing generating assets. The objective is to maximize the economic return on physical assets over their life by achieving desired performance outcomes, while effectively managing the risks inherent in owning, managing and operating a large asset base.

2.2.1 Key Facilities

BC Hydro's seven "Key" generating facilities represent the largest hydroelectric facilities on the BC Hydro system and produce approximately 90 per cent of BC Hydro's average annual energy supply. In the past decade, BC Hydro completed the installation of Unit 5 at Revelstoke generating station and Units 5 and 6 at Mica generating station which have added approximately 1500 MW of capacity to the Power System. In addition, BC Hydro completed sustaining investments to address end of life condition and reliability risks associated with critical equipment. These investments have included turbine overhauls, generator upgrades and replacement of transformers, governors and exciters. Looking ahead, the Bridge River facility contains approximately 30 per cent of all Key facility equipment currently rated as Poor and Very Poor. Capital projects underway will restore the condition of major assets at the facility and improve the aggregate condition at Key facilities.

BC Hydro will continue to focus on preserving reliability at the Key facilities, by directing investments towards mitigating the risks associated with major equipment currently rated as Poor and Very Poor. Under this strategy, investments will be initiated within 10-years to restore Poor and Very Poor equipment to Good or Fair condition in order to support meeting our Service Plan reliability targets and aligning with our objective of having the reliability of our Key facilities at or slightly above the average of similar facilities, as reported by the Canadian Electricity Association.

2.2.2 Strategic Facilities

BC Hydro’s 18 “Strategic” facilities represent all generating stations on Vancouver Island, all stations located on cascading river systems, all thermal generation stations, and generating stations required to provide voltage support to the transmission network. These facilities produce approximately 9 per cent of BC Hydro’s average annual energy and provide significant additional value to BC Hydro due to their geographic location and system support services.

In recent years, there have been considerable investments in Strategic facilities such as the redevelopment of the Ruskin and John Hart facilities which went into service in fiscal 2018 and fiscal 2019, respectively. BC Hydro is also restoring the health of generators such as those at Cheakamus, Seton and Wahleach as well as Strathcona Unit 1 and Ash River on Vancouver Island.

Looking out over the next 10 years, equipment in Poor or Very Poor condition at Strategic facilities will either be refurbished or replaced, will have work underway to be refurbished or replaced, or will have a long-term plan developed to mitigate the risk of equipment failure. Discrete investments are being made at Strategic facilities (including thermal generating facilities) to address the highest risks. However, some smaller strategic facilities (e.g., Alouette and Clowhom) may experience extended forced outages or be forced out of service prior to reinvestment. Alouette is the smallest Strategic facility (9 MW) and is currently out of service. The expected outcome of this strategy is that, in aggregate, the reliability of Strategic facilities will be comparable to similar facilities, as reported by the Canadian Electricity Association.

2.2.3 Available Facilities

BC Hydro’s seven “Available” facilities represent those not included in the other categories and produce less than one per cent of BC Hydro’s average annual energy. Two of these facilities are out of service (Elko and Spillimacheen) and one is partially out of service (Shuswap). Many of the assets at two other facilities (Falls River and Walter Hardman) are in Poor and Very Poor condition. Based on the current plan, the five facilities above will receive minimal capital investment and will be taken out of service when they are no longer able to safely generate electricity. BC Hydro will perform regular maintenance and inspection on these assets to keep them safe and inform investment and operating decisions. Options to refurbish, redevelop or decommission Available facilities that have been taken out of service will be developed as required. There is a high likelihood that a number of these facilities will experience long outages or be forced out of service over the next ten years. BC Hydro expects to continue to provide reliable electricity service to customers with these five facilities out of service.

2.2.4 Dam Safety

BC Hydro operates 85 dams at 41 different sites. Safe operation of a dam considers more than just the physical structure that retains water within the reservoir; it also considers:

- The structures and devices that control and convey water over, through or around the dam leading up to or around the generating station, e.g., spillways, tunnels, penstocks, and gates and valves;
- The natural structures, slopes and barriers that support the dam and surround the reservoir; and
- The supporting infrastructure and instrumentation required to monitor and maintain these various constructed and natural features.

In managing its dams, BC Hydro monitors, maintains and, as necessary and practicable, upgrades all of these structures and devices, natural features and supporting infrastructure. BC Hydro’s dams are diverse in character. They range in size from a few very small dams that are upstream of no or only a few persons, to some of the largest dams in the world that are upstream of several thousands of persons. These dams are classified by the potential consequences of their failure in accordance with the BC Dam Safety Regulation. Of BC Hydro's 41 regulated dam sites:

- 20 are classified as being of Extreme consequence;
- Seven are classified as being of Very High Consequence;
- Three are classified as being of High Consequence;
- 10 are classified as being of Significant Consequence; and
- One is classified as being of Low Consequence.

BC Hydro's dams vary in age from just over 10 years old to over 100 years old, with most being between 40 and 75 years old. The dams are situated in a demanding environment, frequently being stressed by extremes in temperature and high inflows. This leads to continuing and expected deterioration of the structures, in particular the spillways, requiring ongoing maintenance and occasional capital investments to extend their service lives.

The age of the dam also contributes to a state where some equipment is at its end of life or where design approaches in use at the time of its construction are no longer considered to be adequate. This is particularly true when it comes to the operational reliability of spillway gates and other flow control equipment, which presents a risk of malfunction that could lead to gates or valves failing to open when needed to route flood inflows or mis-operation that could cause sudden changes in downstream flows, and endanger the public. BC Hydro actively manages this risk through its continuing program to upgrade and rehabilitate its spillway gates systems.

BC Hydro's dams are located in a part of the world that is subject to natural hazards such as earthquakes and landslides. In response, BC Hydro has developed an industry-leading model to calculate seismic hazards at its dam sites and inform the needs and criteria for seismic upgrades. BC Hydro also maintains a program to monitor the slopes along its reservoirs, which includes instrumentation and drainage infrastructure in some slopes of key interest. Investments are regularly required to replace or remediate this instrumentation and drainage as it ages and loses effectiveness.

BC Hydro has made significant investments in safety upgrades to its dams since 2005, including:

- Approximately $400 million on upgrades to spillway gates systems at various dams, including Hugh Keenleyside and W.A.C. Bennett Dams;
- Over $200 million in upgrades to Ruskin Dam to address seismic and seepage deficiencies, to increase its flood discharge capacity and to replace its spillway gates systems;
- $120 million to replace the deteriorated rip rap on the upstream face of W.A.C. Bennett Dam;
- $65 million to rebuild Coquitlam Dam; and
- $55 million to perform upgrades to the spillway structure at W.A.C. Bennett Dam and stabilize the rock slope above it.

These investments were prioritized to address the biggest identified risks related to BC Hydro's dams. Many other, smaller-scale investments in upgrades to the dams and their infrastructure, such as monitoring instrumentation, have also been made in recent years.

Overall, BC Hydro aims to improve or at least maintain the current level of risk across its entire fleet of dams, which we believe is well within the limits of what is considered to be tolerable. Our strategy considers the availability of the necessary expert engineering services (both internal and external) and experienced construction services, as well as our capacity to oversee this work. Our planned level of investment in dam upgrades is primarily driven by our ability to execute these upgrades effectively. On this basis, required investments in upgrades to BC Hydro's dams have been prioritized over the coming decade and beyond. In the coming years, major investments in BC Hydro's dams will target the biggest current contributors to risk and will be made in the following areas:

- Major upgrades to improve seismic resistance, reservoir discharge capability and spillway gate reliability at the three main dams in the Campbell River system, namely John Hart Dam, Ladore Dam and Strathcona Dam;
- Major upgrades to reduce seepage and improve the seismic resistance of the La Joie Dam and intake tower;
- Upgrades to Cheakamus Dam to improve seismic resistance and reduce the potential for internal erosion;
- Continued upgrades to W.A.C. Bennett Dam to decommission disused and deteriorating low level outlets and sluice gates—eliminating two potential weaknesses in the dam's water barrier—and the dam's network of monitoring instrumentation; and
- Improvements in the seismic resistance and operating reliability of the spillways and gates at Mica Dam and Revelstoke Dam.

Another area of focus will be the upgrade of the instrumentation at Downie slide and Little Chief slide to allow continued and improved monitoring of the landslides and to inform possible stability improvement works in the future. Smaller investments will also be made to improve or replace dam infrastructure such as reservoir booms and miscellaneous instrumentation.

2.3 The Transmission and Distribution System

The overarching strategy for the Transmission and Distribution system is to maximize the long-term value of the system while minimizing the total life cycle costs of assets and ensuring safety and maintaining reliability. The strategy is accomplished by finding the optimal balance between performance, cost, risk, security, regulatory requirements, and environmental and social aspects.

2.3.1 Transmission System

BC Hydro's bulk transmission system includes the 500 kV transmission system, parts of the 345 kV, 287 kV and 230 kV systems, the transmission connections to Vancouver Island, and interconnections with other utilities through transmission interties. These lines connect the large remote generating stations in the Peace River and Columbia River areas with the major load centres of the Lower Mainland and Vancouver Island, which together represent over 70 per cent of the BC Hydro load.

Four regional transmission systems transfer energy within four specific geographic areas of the province: the Lower Mainland, Vancouver Island, Northern and Southern Interior regions. The regional systems generally consist of 230 kV, 138 kV, and 60 kV transmission networks that connect local generation and deliver power to distribution utilities or transmission customers located within the region.

Long-term planning related to bulk and regional transmission needs are typically associated with moving energy over long distances. Long-term planning considers a wide range of supply-side and demand-side options, resulting in an integrated system plan. BC Hydro conducts assessments to evaluate the transfer capability of the system and to ensure the system meets the Mandatory Reliability Standards for transmission system planning performance. Investments are identified that are necessary to fund transmission system capacity additions.

2.3.1.1 Lower Mainland and Vancouver Island

In the last decade BC Hydro has made significant investments to increase the capacity of the bulk transmission system including the Interior to Lower Mainland and Vancouver Island Transmission Reinforcement projects. These investments have enhanced BC Hydro's ability to continue to serve the electricity needs of our customers in the highest density areas of the province.

With the completion of the Interior to Lower Mainland transmission line, installation of Mica Units 5 and 6 and the third transformer at the Meridian substation, the natural gas fired, peak generation capability from the Burrard Generating Station is no longer required to meet critical loads in the Lower Mainland. Accordingly, Burrard is instead being operated to provide voltage support for the transmission system in the Lower Mainland, using its capability to operate in synchronous condense mode. The four Burrard Synchronous Condenser units are now reaching end of life and are expected to experience reliability issues within the short to medium term. The near-term focus of capital investment in the Lower Mainland transmission system will be to maintain BC Hydro's Lower Mainland bulk transmission system reliability during heavy winter load periods under single contingency conditions.

Ensuring the reliability of service in the region also requires addressing reliability risks associated with the end of life condition of 230 kV high voltage cables in the short term. These include the cable between Horsey substation and Goward substation in Victoria, a partial replacement of the 230 kV cable between Barnard substation and Como Lake substation, as well as addressing the reliability of transmission supply to the Gulf Islands.

BC Hydro has recently been addressing an emergent issue on the 500 kV submarine cables to Vancouver Island. This is discussed further in Chapter 6, section 6.4.2.2.

2.3.1.2 Northern Region

BC Hydro is investing in the Northern transmission system to address load and system growth requirements driven primarily by the development in the Oil and Gas sector in the Peace and North Coast regions. Recent investments include the 230 kV Peace Region Electric Supply project and interconnecting major industrial customer loads in this region.

Due to the continued economic activities expected in the Liquefied Natural Gas and Oil and Gas sectors, there are potentially significant additional upgrades to the transmission system in the North Coast and Peace region that may be required in the short to medium term which are not included in BC Hydro's Capital Plan. BC Hydro will work with customers in the area to define the need and scope of future projects. Projects will proceed once there is a formal commitment from potential customers. Expanding the capacity of the electricity supply in this region of the province will enable BC Hydro to supply reliable power to our industrial customers and help reduce greenhouse gas emissions by enabling customers to use clean electricity rather than fossil fuels to power their operations.

BC Hydro will also be investing to improve customer reliability in the region through investments such as the 5L63 Telkwa Relocation project, which will relocate a segment of the radial line that serves customers on the north coast and is currently situated in an active landslide area.

2.3.1.3 Southern Interior Region

BC Hydro is continuing to invest in the transmission system in the Southern Interior region of the province to provide reliable service to our customers. BC Hydro is continuing to evaluate alternatives for adding redundant supply to West Kelowna. BC Hydro is also moving forward with its strategy to ensure adequate transmission to meet the needs of the Bridge River regional system. Elsewhere in the region, BC Hydro is not expecting any major investments to serve load growth in the medium to long term as there is sufficient capacity to meet the load forecast.

2.3.2 The Regional Substation and Distribution System

BC Hydro has four regional systems (the Lower Mainland; the Northern Interior; the Southern Interior; and Vancouver Island) which connect the transmission system to the local distribution systems. The substation and distribution network are made up of over 300 stations and 68,000 kilometres of distribution circuits in order to serve customers throughout the province.

In the past decade, BC Hydro has built 28 new substations within these regions, including 12 distribution substations enabling BC Hydro to supply more than 900 MVA additional load at distribution voltages. Projects have included Fleetwood substation in Surrey, Big Bend substation in South Burnaby, the West Kamloops substation in Kamloops and the upgrade expansion of Horne Payne substation. In addition to the increased capacity, these new substations have improved the operational flexibility of the system. In some cases, the addition of new substations has facilitated the load transfer from other substations that were reaching end of life or ultimate capacity. This approach helps BC Hydro minimize the total cost of capital investment and maintenance over the life cycle of the substations.

We have also completed the Smart Metering and Infrastructure Program, which included the installation of 1.9 million smart meters in homes and businesses across the province. This provides an advanced telecommunications infrastructure to support electricity system management and customer applications, and information technology to support customer billing, load forecasting and outage management systems.

Our investments in the regional systems mean that BC Hydro’s capacity to reliably serve the forecast load growth in many areas of the province has been enhanced.

Load growth in certain areas of the province, particularly the Fraser Valley, will require continued investment in new substation and distribution infrastructure to reliably supply customers.

BC Hydro will continue to mitigate end-of-life, safety and environmental risks by investing in new substations, such as the new West End Substation in downtown Vancouver. This new substation will enable the load transfer from Dal Grauer and Murrin substations, which have reached end of life, and have many risks including safety and seismic. For other existing stations, a component-by-component asset replacement strategy may be implemented, such as at Horsey substation, to replace assets as needed. One of the key considerations in determining the timing and strategy of investments is the requirement to replace equipment with polychlorinated biphenyl levels at or above 50 ppm by the December 31, 2025 Federal Regulation deadline.

3 BC Hydro's Strategies, Plans and Studies

As part of its planning practices, BC Hydro identifies investments required on the Power System by evaluating the issues, risks and opportunities related to Power System assets. Long term planning information is captured in planning documents such as strategies, plans and studies.

At times the terms strategy, plan and study may be used interchangeably to refer to a document that is used to support long-term asset investment planning. Strategies generally cover the asset management approach for an entire population of an asset class. Plans are most often used for a specific facility, such as a substation or generating facility, incorporating the results of any relevant asset-based strategies. Studies are generally a technical analysis undertaken when the system needs extend beyond a facility and may incorporate the needs of multiple facilities and asset classes.

For the Power System, documents such as these help BC Hydro to assess system needs and develop solutions based on a region or area, river system, a facility or group of facilities, and asset classes. These planning documents provide context with respect to the rationale for investments that are either underway or planned to start in the future. In some instances, changing underlying factors, such as adjustments to load growth forecasts, resource or financial constraints, deterioration in asset condition as well as new information or corporate priorities can lead to a change in the original scope of projects or solutions proposed in these planning documents. This means that while the planning documents capture the essence of the approach, the plans and investments proposed may change in response to new information. These changes will be reflected in the planning documents during the next update of the strategy, plan or study. The process through which Power System strategies, plans and studies are developed is explained in detail as part of the bottom-up planning process descriptions included in Appendix N.

The summaries within this appendix belong to one of the following categories:

- **Strategies**: Asset class focused, considering the condition and performance of each asset with the goal of optimizing its value over the life cycle of the asset. Examples include:
  - **Transmission and Distribution Asset Strategies:** BC Hydro has documented Asset Strategies for most of its Transmission and Distribution key asset classes. These Asset Strategies provide a program approach to the management of each asset class across the entire system, and over the entire asset lifecycle.

- **Plans**: Generally related to a facility, documenting the proposed investments for each facility considering the facility's role, performance expectations, risks, issues and growth opportunities. Examples include:
  - **Generation Facility Asset Plans:** Generation facility asset plans outline the proposed long-term investment strategy at a specific time. Facility Asset Plans are key inputs to the planning process and may be informed by asset strategies. The investment strategies that are proposed for discrete facility asset plans are reviewed by management and prioritized to provide the most appropriate suite of investments across the system given resource and financial constraints, outage planning, and other considerations; and
  - **Transmission and Distribution Substation Facility Asset Plans:** These plans are developed when a substation requires major investments to address end-of-life and other sustaining needs and may be informed by asset strategies. The longer-term capacity needed at the substation is also integrated into the Facility Asset Plan.
- **Studies**: Focused on a specific area or system, integrating multiple needs within a similar timeframe, so that they can proceed through the planning process in an integrated approach. Examples include:
  - **Transmission and Distribution Area Studies:** These area studies are typically prepared, or updated, when capacity additions are required in an area, which may include optimizing system reinforcements for transmission, substation, and distribution systems in the specific area. Other known needs in the area, including addressing or aligning sustainment needs at the area's substations, are integrated into the Area Studies; and
  - **Dam Safety System Studies:** These studies are initiated to identify options that would permit the optimal risk management and investment strategy for the system using a Systems Engineering approach. A Systems Engineering

approach provides a framework to manage complexities within the constraints of the river system to ensure technical coordination across a broad range of disciplines.

Not all projects in the Capital Plan may be related to an underlying strategy, plan or study (for example where emergency work is being completed and any required studies are going to be completed as part of the scope of the actual project) and some investments may have multiple references. Where applicable, the most relevant strategies, plans, or studies for the investments listed in Appendix I have been identified in column Y. A summary of the identified strategies, plans and studies are provided in this appendix. These documents can cover a period of up to 30 years or longer in some cases. Within each of the summaries in this appendix, the following principles were applied for identifying investments within the Short, Medium and Long-Term time frames:

- **Short-Term:** Investments with expenditures within the fiscal 2023 to fiscal 2025 test period are defined in the Short-Term Solution;
- **Medium-Term:** Investments with expenditures anticipated to start within the next 10 years, but after the fiscal 2023 to fiscal 2025 test period are outlined in the Medium-Term Solution; and
- **Long-Term:** Investments with potential expenditures beyond the next 10 years are summarized in the Long-Term Solution.

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix K

Attachment 1

Power System Strategies, Plans and Studies

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Generation			
Hydroelectric			
Growth			
N/A			
Redevelopment / Rehabilitation			
N/A			
Dam Safety			
Bridge River 2 - Strip and Recoat Penstock 2 Interior	1	Page 7	Pages 11 and 5
Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)	2	Page 15	Pages 14 and 5
Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment	3	Page 48	Page 31
Revelstoke Replace Downie Slide Instrumentation	4	N/A	Page 39
Comox - Puntledge Flow Control Improvements	5	Page 17	Page 37
John Hart Dam Seismic Upgrade	6	Page 32	Pages 3 and 22
Ladore Spillway Seismic Upgrade	7	Page 44	Pages 3 and 29
Mica - Intake Gantry Crane Refurbishment	8	N/A	Page 33
Strathcona Upgrade Discharge	9	Page 78	Pages 3 and 47
W.A.C. Bennett Dam Seal Low Level Outlets	10	Page 89	Page 18
Alouette - Environmental Flow Discharge Upgrade and LLO Sealing	11	N/A	Page 7
Alouette Improve Headworks & Surge Tower Seismic Stability	12	Page 1	Page 7
Ash River Extend Life of Steel Penstock	13	Page 3	Pages 9 and 5
Bridge River 1 - Improve Slope Drainage	14	N/A	Page 11
Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior	15	Page 7	Pages 11 and 5
GMS – Install Further Instrumentation for Monitoring Embankment Condition	16	N/A	Page 18
Hugh Keenleyside - Spillway and Low Level Outlets Concrete Upgrade	17	Page 30	Page 20

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Hugh Keenleyside - Fire Protection System Upgrade	18	N/A	Page 18
La Joie - Dam Improvements	19	Page 40	Pages 27 and 1
Mica - Discharge Facilities Seismic and Reliability Upgrades	20	Page 55	Page 33
Terzaghi - Spillway Chute Access Improvement	21	N/A	Page 11
Various Sites - Reservoir Booms Replacement - F2020	22	Page 83	N/A
W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates	23	Page 86	Page 18
Bridge River 1 - Penstock Concrete Foundation Refurbishment	24	Page 5	Page 11
Cheakamus - Dam Improvements	25	Page 13	Page 14
G.M. Shrum - Intake Operating Gate and Intake Maintenance Gate Refurbishment	26	Page 27	Page 18
G.M. Shrum - Intake Operating Gate Hydraulic Upgrade	27	Page 27	Page 18
Hugh Keenleyside - Cranes Upgrade	28	N/A	Page 20
Kootenay Canal - Canal Concrete Liner Joints Upgrade	29	Page 35	Page 25
Lake Buntzen 1 - Penstock Interior Restoration	30	Page 50	Page 31
Mica - Little Chief Inclinometers Installation	31	N/A	Page 33
Ruskin - Left Abutment Slope Sinkhole Remediation	32	N/A	N/A
Seton - Canal Flow Control Structure Upgrade	33	Page 71	Pages 41 and 1
Sugar Lake - Dam Abutments Upgrade	34	N/A	Page 45
Terzaghi - Dam Instrumentation Upgrade	35	N/A	Page 11
Terzaghi - Low Level Discharge Reliability Improvement	36	Page 81	Pages 11 and 1
Various Sites - Probabilistic Seismic Hazard Model Update	37	N/A	N/A
Various Sites - Spillway Gate Standby Power Improvements	38	Page 85	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Sustaining - Other			
Cheakamus Replace Units 1 and 2 Turbine Inlet Valves	39	N/A	Page 14
G.M. Shrum G1 to 10 Control System Upgrade	40	Page 20	Page 18
G.M. Shrum Upgrade HVAC System	41	Page 22	Page 18
Hugh Keenleyside Recoat Navlock Gates	42	N/A	Page 20
Hugh Keenleyside Replace Service Water Piping	43	N/A	Page 20
Jordan - Upgrade Governor & PRV Controls	44	N/A	Page 23
Mica - Reactor 5RX3 Replacement	45	Page 52	Page 33
Mica Modernize Controls	46	Page 57	Page 33
Mica Replace Units 1 to 4 Generator Transformers	47	Page 59	Page 33
Mica Upgrade 600V Circuit Breakers	48	Page 63	Page 33
Mica Upgrade HVAC System	49	Page 65	Page 33
Peace Canyon - 600V Circuit Breaker Upgrades	50	N/A	Page 35
Puntledge Recoat Interior and Exterior of Steel Penstock	51	Page 67	Pages 37 and 5
Revelstoke Replace Fire Alarm System	52	N/A	Page 39
Seven Mile - Replace T1 Transformer	53	N/A	Page 43
Seven Mile Upgrade Powerhouse Crane Controls	54	N/A	Page 43
Various - Water License Renewal	55	N/A	N/A
Wahleach Recoat Penstock (Interior and Exterior)	56	N/A	Pages 49 and 5
Wahleach Refurbish Generator	57	Page 91	Page 49
Waneta U3 Life Extension	58	Page 93	N/A
Bridge River 1 Replace Units 1-4 Generators / Governors	59	Page 9	Page 11
Various Sites - Cutler Hammer Exciters Upgrade	60	N/A	Page 16
Whatshan - Governor Replacement	61	N/A	Page 51
Ash River - Upgrade Communication Systems	62	N/A	Page 9
GMS - Unwatering System Refurbishment	63	Page 29	Page 18
Kootenay Canal - U1 - U4 Generators Refurbishment	64	Page 37	Page 25
Kootenay Canal Modernize Controls	65	Page 38	Page 25
Lake Buntzen 1 - Generator Replacement	66	Page 46	Page 31
LDR - Upgrade Communication Systems	67	N/A	Page 29

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Mica - U1 - U4 Circuit Breaker and Iso-phase Bus Replacement	68	Page 54	Page 33
Peace Canyon - U1 - U4 Exciter Replacement	69	N/A	Page 35
Revelstoke - U1 - U4 Stator Replacement	70	Page 69	Page 43
Seton - Upgrade Unit	71	Page 73	Page 41
Various Facilities Replace Water Level Gauges	72	N/A	N/A
Ash River - Generator Replacement	73	N/A	Page 9
Bridge River 2 - Transformer Replacement	74	N/A	N/A
G.M. Shrum - Pauwels Transformer Life Extension	75	N/A	Page 18
G.M. Shrum - Physical Security Upgrade - Phase I	76	Page 24	Page 18
G.M. Shrum - U5 Generator Refurbishment	77	Page 25	Page 18
G.M. Shrum - U6 Generator Refurbishment	78	Page 26	Page 18
Kootenay Canal - Fire Detection and Alarm System Replacement	79	N/A	Page 25
Ladore - Unit Transformer Upgrade	80	N/A	Page 29
La Joie - Governor Pressure Regulating Valve Replacement	81	Page 42	Page 27
Mica - Crash-rated Gate Replacement	82	N/A	N/A
Mica - Nagle Creek Crossing Infrastructure Refurbishment	83	N/A	Page 33
Mica - U1 - U2 Turbine Overhaul	84	Page 61	Page 33
Peace Canyon - High and Low Pressure Piping Replacement	85	N/A	Page 35
Peace Canyon - Powerhouse, Intake and Tailrace Crane Upgrades	86	N/A	Page 35
Revelstoke - Intake and Tailrace Gantry Crane Upgrades	87	N/A	Page 39
Seven Mile - U1 - U3 Turbine Upgrade	88	Page 76	Page 43
Seven Mile - U1 - U4 Controls Upgrade	89	Page 75	Page 43
Various Sites - PCB Lighting Remediation (F2022-F2024)	90	N/A	N/A
Diesel			
N/A			

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Thermal			
Burrard - Modify for Post Generation Operations	91	N/A	Page 13
Fort Nelson - U2 Steam Turbine Overhaul	92	N/A	Page 17
Transmission			
Growth Capital Expenditures			
Regional System Reinforcement			
Bridge River Transmission Project	1	Page 104	Page 75
North Montney Region - Electrification	2	Page 136	Page 95
West Kelowna Transmission and Westbank Upgrade Projects	3	Page 162	Page 96
West End - Substation Construction and System Reinforcement	4	Page 160	Page 77
Peace to Kelly Lake - Remedial Action Scheme Upgrade	5	N/A	N/A
East Vancouver - Substation Construction	6	Page 110	Page 77
Sunshine Coast - Transmission Reinforcement	7	Page 151	N/A
Bulk System Reinforcements			
Cranbrook 5L94 - Line Reactor Replacement	8	N/A	N/A
Lower Mainland - Capacitive and Reactive Power Reinforcement	9	Page 123	Page 76
Prince George to Terrace Capacitors Project	10	Page 146	N/A
Station Expansion & Modification			
Capilano Substation Upgrade	11	Page 106	Page 80
Clayburn Substation Upgrade	12	Page 108	Page 53
Mount Lehman Substation Upgrade	13	Page 128	Page 53
Horne Payne - Feeder Section Addition	14	Page 114	Page 87
Generator Interconnections			
N/A			
Transmission Load Interconnections			
Customer IPID - 901580	15	N/A	N/A
Customer IPID - 901573	16	N/A	N/A
Customer IPID - 901851	17	N/A	N/A
Customer IPID - 901581	18	N/A	N/A
Customer IPID - 901940	19	N/A	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Customer IPID - 902121	20	N/A	N/A
Customer IPID - 901943	21	N/A	N/A
Customer IPID - 901938	22	N/A	N/A
Sustaining Capital Expenditures			
Circuit Breakers			
SPG Metalclad Switchgear Replacement	23	Page 149	Page 92
Kimberley to Marysville - Substation Relocation	24	Page 119	Page 60
Pemberton - Substation Rebuild	25	N/A	Page 60
Maple Ridge - Feeder Section 60 Series Refurbishment	26	Page 127	Page 60
Other Power Equipment			
American Creek - Capacitor Protection Control Upgrade	27	N/A	Page 56
Barnard 50/60 Feeder Section Replacement	28	Page 100	Page 73
Hundred Mile House T1/T2 EOL Replacement	29	N/A	Page 69
Jordan River - Switchyard Upgrade	30	Page 115	Page 69
SC Excitation Systems Upgrade - VIT/KLY	31	N/A	Page 68
Natal Sub - NTL 60-138 kV Rebuild	32	Page 130	Page 85
Sandspit Substation Replacement	33	N/A	Page 97
Ah-sin-heek - Substation Replacement	34	N/A	Page 97
Bridge River - T4 Transformer Replacement	35	Page 102	Page 69
Kennedy - 5CX1 Controls Replacement (Emergency)	36	N/A	N/A
Oldfield - Substation Feeder Section Upgrade	37	N/A	Page 89
Peace to Kelly Lake - Stations Sustainment	38	Page 140	Pages 59, 66 and 67
VIT & KLY Hydrogen Gas Sys - Safety Upgrade	39	N/A	Page 68
KI1 60Kv Renovation, 4Kv Decommission & Control Room	40	Page 117	Page 82
Mainwaring Station Upgrade	41	Page 125	Page 84
Newell Substation Upgrade	42	Page 134	Page 86
Patricia - Substation Upgrade	43	Page 138	Page 91
Peace Region to Kelly Lake - Reactor Replacement (Phase 2)	44	Page 142	Page 67
Kelly Lake - Reactor Installation	45	N/A	Page 68

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Norgate - Substation Bypass	46	N/A	Page 80
Peace Region to Kelly Lake - Reactor Replacement (Phase 3)	47	Page 142	Page 67
Peace Region to Kelly Lake - Reactor Replacement (Phase 4)	48	Page 142	Page 67
Telegraph Creek - Substation Replacement	49	N/A	Page 97
Protection and Control			
GMS Substation - Control Systems Upgrade	50	N/A	Page 56
NERC CIP V5 Compliance at Medium Impact T&D Stations	51	Page 132	Page 56
Control PLC984 and RTU Replacement (WSN)	52	N/A	Page 56
Various Sites - NERC CIP-003v7 Implementation	53	Page 156	Page 56
Stations Auxiliary Equipment			
Joseph Creek (JOE) Substation Upgrade	54	N/A	Page 97
Canal Flats - Substation Wood Pole Replacement	55	N/A	Page 97
Skookumchuck - Substation Wood Pole Replacement	56	N/A	Page 97
Cathedral Square - Substation HVAC Upgrade	57	N/A	Page 59
Lumby #2 - Substation Wood Pole Replacement	58	N/A	Page 97
Port Alberni - Substation Refurbishment	59	Page 144	Page 59
Prevost - Substation Control Building Upgrade	60	N/A	Page 59
Woss - Substation Wood Pole Replacement	61	N/A	Page 97
Stations Risk Mitigation			
Oil Spill Containment - F17/F18 (ALZ / MDN)	62	N/A	Page 64
Stations Seismic Upgrade -F16/17 (9 Stations)	63	N/A	N/A
Project IPID - 900766: Jeune Landing - Substation Acquisition and Upgrade	64	N/A	N/A
Telecommunications			
Vancouver Island Radio System	65	Page 154	Page 71
Various Sites - Mountain Top 1603 Replacement	66	N/A	Page 71
System Wide – Bulk Electric System Telecom Equipment Replacement	67	Page 152	Page 71
Various Sites - Telecom Analog Private Line Replacement	68	N/A	Page 55

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Fraser Valley - Telecom System Reliability Upgrade	69	N/A	Page 79
Various Sites - MPLS Core Router Upgrade	70	N/A	Page 71
Various Sites – Telecom Transport Network Resiliency Enhancement	71	Page 158	Page 93
Cable Sustainment			
2L146 - Cable Replacement	72	Page 96	Page 63
Coquitlam - 2L51 Partial Replacement	73	N/A	Page 63
Gulf Islands - Transmission Reinforcement	74	Page 112	Page 63
South Fraser Transmission Relocation Project	75	Page 148	N/A
O/H Lines Life Extension			
5L063 Telkwa Relocation	76	Page 98	N/A
Long Span Crossing Refurbishment - F17/F18 (1L37)	77	Page 121	Page 58
O/H Lines Risk Mitigation			
1X387AMX – Kitsault Transmission Line Hazard Mitigation	78	N/A	N/A
2L003 and 2L049 – Transmission Line Crossing Seismic Upgrade (Second Narrows)	79	Page 95	Page 74
ROW Sustainment			
N/A			
Third Party Requested Transmission Line Relocations			
Customer IPID - 901563	80	N/A	N/A
Customer IPID - 901807	81	N/A	N/A
Distribution			
Growth Capital Expenditures			
Customer Driven			
Customer IPID DY-1545	1	N/A	N/A
Customer IPID DY-0347	2	N/A	N/A
Customer IPID 901955	3	N/A	N/A
Customer IPID 902127	4	N/A	N/A
Customer IPID 902128	5	N/A	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
System Expansion and Improvement			
LOH 12F56, 12F62 Voltage Conversion Preparation (LM-BBY-082)	6	N/A	N/A
Mount Lehman New Feeder to Offload Balfour, Mount Lehman and Gloucester Feeders (FV-ABT-042)	7	N/A	N/A
Two new CBN Feeders to Offload SMW (LM-FVE-606)	8	N/A	N/A
Glenmore Voltage Conversion (LM-NSC-088)	9	N/A	N/A
Norgate - Offload NOR loads to NVR feeders (LM-NSH-074)	10	N/A	N/A
North Vancouver - Offload NVR loads to LYN new feeders (LM-NSH-075)	11	N/A	N/A
Oldfield (OFD) Voltage Conversion 12 to 25kV (NI-NEW-273)	12	N/A	N/A
Three Fleetwood feeders to offload McLellan (FV-FVW-723)	13	N/A	N/A
Three new MLE Feeders to offload CBN (LM-FVE-607)	14	N/A	N/A
Downtown Vancouver - Voltage Conversion Preparation for Customer Vaults (LM-VAN-210)	15	N/A	N/A
Fleetwood - Distribution Feeder Ductbank and Feeder Installation (FV-FVW-023)	16	N/A	N/A
Fleetwood - Distribution Feeder Ductbank and Feeder Installation (FV-FVW-805)	17	N/A	N/A
Langley - MLN 25F32 and MLN 25F33 Offload (FV-FVW-741)	18	N/A	N/A
Tofino - New LBH 25F54 Feeder Installation To Offload LBH 25F52 (VI-PAL-010)	19	N/A	N/A
Vancouver Island - Saltspring 25F61 Cable Extension to North Pender Island (VI-GUL-005)	20	Page 170	N/A
Sustaining Capital Expenditures			
System Expansion and Improvement			
Downtown Vancouver - Underground Murrin Feeders to Eliminate H-Frames in Gastown	21	Page 165	N/A
H-Frame Elimination - Chinatown	22	Page 167	N/A
Mission - Feeder 25F51 Tie (FV-ABT-039)	23	N/A	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
100 Mile House - Relocate Sections of Transmission along Hendrix Road (SI-HMH-002)	24	N/A	N/A
Gwillim Microwave - Power Supply Upgrade	25	N/A	N/A
Asset Replacement			
Various Sites - LED Street Light Conversion	26	Page 172	Page 99
Electric Vehicle Charging Infrastructure			
N/A			
Beautification			
N/A			
Technology			
Manage Compliance and Security			
Projects Over $2 million			
NERC CIP-13	1	N/A	N/A
MRS Compliance System Project - SigmaFlow	2	N/A	N/A
Time Based Rates	3	N/A	N/A
Privileged Access Management	4	N/A	N/A
Splunk Subscription License Acquisition	5	N/A	N/A
Cisco Enterprise License Acquisition	6	N/A	N/A
Corporate Firewalls Refresh	7	N/A	N/A
Manage Risk and Sustain Productivity			
Projects Over $2 million			
SAP S/4HANA Upgrade	8	Page 185	N/A
Human Capital Management (HCM) Foundation	9	N/A	N/A
SAP Business Warehouse on HANA Migration	10	N/A	N/A
Contact Centre Technology Foundation Refresh	11	Page 176	N/A
GE Smallworld GIS Platform Upgrade	12	N/A	N/A
SAP Customer Front End Replacement	13	N/A	N/A
Openway Migration	14	N/A	N/A
Energy Management System (EMS) 3.x Upgrade	15	Page 179	N/A
Primary Data Centre Network Refresh	16	N/A	N/A
Backup Data Centre Network Refresh	17	N/A	N/A
Operations Data Centre Network Refresh	18	N/A	N/A
Windows Server Upgrade	19	N/A	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Data Centre Backup	20	Page 184	N/A
Data Centre Backup Sustainment	21	N/A	N/A
Data Centre Backup Sustainment	22	N/A	N/A
Physical Security Network Transition	23	N/A	N/A
EAS Greenplum Hardware Upgrade	24	N/A	N/A
Corporate Telephony Replacement	25	Page 183	N/A
Corporate Telephony Replacement	26	Page 183	N/A
Regional site infrastructure refresh	27	N/A	N/A
Meter Data Management System Upgrade	28	N/A	N/A
Projects and Programs less than $2 million			
N/A			
Enhance Business Capability			
Projects over $2 million			
Dam Safety Information System (DSIS)	29	N/A	N/A
Vehicle and Equipment Telemetry	30	N/A	N/A
Advanced Distribution Management System (ADMS)	31	Page 174	N/A
Stations Work Management	32	Page 186	N/A
Distribution Design Modernization	33	Page 178	N/A
Programs over $2 million (Recurring Capital)			
N/A			
Projects and Programs less than $2 million			
N/A			
Properties			
Chilliwack Field Building Redevelopment	1	Page 187	N/A
Materials Classification Facility Building Redevelopment	2	Page 189	N/A
Kamloops Field Building Redevelopment	3	Page 191	N/A
North Vancouver Field Building Redevelopment	4	Page 193	N/A
Campbell River II Field Building Redevelopment	5	Page 195	N/A
Dunsmuir Roof & 18th Floor HVAC Upgrade	6	N/A	N/A
Duncan Field Building Redevelopment	7	Page 197	N/A
Mica Staff Accommodations Building Redevelopment	8	N/A	N/A
Prince Rupert Field Building Redevelopment	9	N/A	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Edmonds Operations Centre Truck Bay Upgrade	10	N/A	N/A
Surrey LMS Truck Bay Upgrade	11	N/A	N/A
Queen Charlotte City Field Building Redevelopment	12	N/A	N/A
Cranbrook Field Building Redevelopment	13	Page 199	N/A
Fort St. John Field Building Redevelopment	14	N/A	N/A
Business Support Other			
Other Technology			
Mobile Radio Optimization - LM	1	N/A	N/A
Fleet/Vehicles			
Fleet/Vehicles	2	N/A	N/A
Business Support - Other			
Material Management - Oil Management Operating Infrastructure	3	N/A	N/A
Site C Project			
Site C	1	Page 201	N/A

Name of Capital Strategy, Plan or Study: Bridge River System Study
Summary of Issue: The Bridge River Generation System is a cascade of three hydroelectric projects located in the Squamish Lillooet Regional District. It includes Downton, Carpenter and Seton Lakes which are upstream of the La Joie, Terzaghi and Seton dams, respectively. It also includes the La Joie, Bridge 1 and 2 and Seton Generating Stations. Many of BC Hydro's assets in the Bridge River Generation System were constructed in the 1950s and 1960's and are in the late stages of their life cycle. Decisions are needed to be made about refurbishment, replacement, decommissioning or reconfiguration of existing BC Hydro facilities. In 2011, BC Hydro initiated a study to evaluate the best long-term configuration for the Bridge River Generation System. The objective of the Bridge River System Study was to establish a river system investment strategy that addressed risk, issues and opportunities at a system and facility level, providing BC Hydro with the required guidance for asset decisions and for prioritizing the Bridge River Generation System investments against those to be made across BC Hydro's fleet. The System Study included scoping level assessment of the capital costs, energy benefits, and risk reduction achieved by alternatives. The System Study also included qualitative consideration of potential environmental and social impacts associated with system alternatives but did not include a detailed examination of these complex interactions. The System Study defined the following Key Capability Requirements for the Bridge River Generation System, which were considered in developing and comparing several alternative integrated river system concepts: • Generate power from the Bridge River Generation System; • Maintain reservoir levels within acceptable bounds under operational based loading and plant fault conditions; • Maintain downstream river flow within acceptable bounds under operational based loading conditions; • Be supported by the First Nations; • Maintain hydraulic control during floods; and • Maintain hydraulic control post-earthquake.
Summary of Solution: The Bridge River System Study (completed in 2014) concluded that, from the perspective of both maximizing energy benefits and minimizing risks associated with the dams, the preferred future configuration is substantially the same as currently exists. Upgrades were proposed, however, so that the Bridge River Generation System could better satisfy the Key Capability Requirements. The System Study prioritized and recommended sequencing of the capital projects by comparing the risk reduction cost effectiveness for the leading concepts. The System Study also identified remaining information gaps that would further inform sequencing and scope of investment decisions. As recommended, BC Hydro subsequently conducted a seismic performance assessment at Terzaghi Dam which established that, with some upgrades to the dam and appurtenances, the dam would be capable of meeting current seismic standards. As a result, BC Hydro is advancing more moderate dam safety projects at Terzaghi Dam rather than replacing the Terzaghi Dam, as had been originally proposed in the base case of the System Study. BC Hydro also decided not to relocate the Bridge River 1 Generating Station. Analysis of the risk reduction by cost had the relocation of the generating station ranked last out of all dominant risks. When coupled with the length of time it would take to relocate the generating station and the risk of stranding assets and the inability to manage flows, BC Hydro decided to proceed with a component by component replacement program at the Bridge River 1 Generating Station. A preferred strategy for sequencing of the risk reductions was refined during development of the capital plan and the Facility Asset Plans for La Joie, Bridge River, and Seton.

Short-Term:

A number of projects dealing with the highest priority dam safety issues and risks are already underway. Investments planned for the short term are as follows:

- La Joie Dam – upgrade the dam and intake tower to address seismic risks. The project is currently in the Identification phase to evaluate and select the leading alternative;
- Bridge River 1 and 2 Generating Stations – address risks of aging penstocks by recoating penstock surfaces and refurbishing the penstock concrete foundations;
- Terzaghi Dam – construct a downstream infill berm to improve seismic performance of the embankment dam;
- Terzaghi Dam – upgrade the low-level outlet and equipment to improve the long-term operational reliability and maintainability of the low-level discharge system;
- Seton Generating Station – replace the aging generating unit to address generator and runner failure risks and install hydraulic bypass system to maintain flow rates during unit outages;
- Seton Dam – upgrade and replace the five headworks gates that are required to isolate the power canal from Seton Lake Reservoir such that they can operate and be closed under a range of water flow conditions; and
- Seton Canal – refurbish the canal's concrete slabs and the joints between them along the four-kilometer-long canal lining.

Medium-Term:

- Terzaghi Dam – upgrade earthfill dam upstream cut-off to manage risks of sinkholes.
- Bridge River 1 and 2 Generating Stations – seismically upgrade the intake towers that pass water from Carpenter Reservoir to the generating stations.
- Seton Canal – seismically upgrade the aqueduct structure that carries flows from the canal over Cayoosh Creek.
- Seton Dam – improve the seismic withstand of the left bank dyke, including treatment for potential foundation liquefaction, and prevention of erosion during normal and flood conditions.
- Bridge River 1 Generating Station – replace the penstock inlet valves with valves that are capable of closing under a full rupture event.

Long-Term:

- Seton Dam – upgrade the Seton Dam to improve the seismic withstand capacity.

Name of Capital Strategy, Plan or Study: Campbell River Systems Engineering Assessment
Summary of Issue: The Campbell River hydroelectric system on Vancouver Island consists of three reservoirs and dams (Strathcona, Ladore and John Hart) which are close-coupled and in series on the Campbell River. All three facilities are categorized as Extreme Consequence per the BC Dam Safety Regulation. The Campbell River system is an important water resource that makes a major contribution to power generation on Vancouver Island, supports valuable fish habitats and spawning grounds, and provides a wide range of community and recreational services in the area. The objective of the Campbell River Systems Engineering Assessment (completed in 2012) was to identify the preferred risk management strategy for the Campbell River system in view of the potential for future redevelopment. Previous investigations into dam safety deficiencies in the Campbell River system identified that: • John Hart Dam and Strathcona Dam have wide-ranging seismic deficiencies. At Strathcona Dam these deficiencies are compounded by the seismically deficient powerhouse and generation water passage that runs beneath the dam; • The spillway gates system at Ladore Dam has insufficient resistance to seismic loads; and • The spillway gates systems at all three dams have operational reliability deficiencies. Owing to their common period of original design and construction, the seismic deficiencies at these dams make all of them vulnerable to failure in an earthquake of intensity expected to occur, on average, once every 500 to 1000 years. Given that these are all Extreme consequence dams, current expectations – as outlined in the Canadian Dam Association’s Dam Safety Guidelines – are that they should be able to withstand an earthquake of intensity expected to occur once every 10,000 years. In 2009, knowing that significant reliability and dam safety investments on this system were going to be required, BC Hydro initiated a top-down systems engineering assessment that investigated the full range of options for the development of the river system in order to identify how investments should be prioritized to deliver safe and sustainable long-term management of the river system assets. The range of configurations was bounded at one end by full or partial decommissioning and at the other end by a complete re-configuration and redevelopment of the entire system. Conceptual solutions included the following considerations: • Least total risk (to people, property and the environment) configuration; • Maximum peak demand availability; and • Maximum total energy output per year. The Campbell River Systems Engineering Assessment concluded that the river system should not be substantially reconfigured and confirmed that redevelopment of the generating capability at John Hart would be appropriate. It further concluded that improvements in seismic withstand and operational reliability of the flood discharge systems at all three main dams are required and, finally, that protection against flooding is best achieved through adequate storage upstream of Strathcona Dam.
Summary of Solution: The Campbell River Systems Engineering Assessment prioritized and recommended sequencing of the capital projects by reviewing the relative costs of the projects versus the anticipated risk reductions. A preferred strategy for sequencing of the risk reductions was refined during development of the capital plan and the Facility Asset Plans for Strathcona, Ladore and John Hart. The strategy considers technical resource availability along with our understanding of the precedent project timelines and numerous site and project timing and schedule requirements. One of the projects considered within this strategy, the John Hart Generating Station Replacement, is now in service.

Short-Term:

A number of projects dealing with the highest priority dam safety issues and risks are already underway. These projects will address the inadequate seismic withstand of various components of John Hart and Ladore Dams and establish a deep drawdown capability at Strathcona Dam for post-earthquake response. These projects will also address reliability deficiencies in the three dams' spillway gates systems. They are:

- John Hart - Dam Seismic Upgrade;
- Ladore - Spillway Seismic Upgrade; and
- Strathcona - Upgrade Discharge.

Medium and Long-Term:

In the medium term, projects to address the inadequate seismic withstand of the Strathcona generating station water passage under the dam and of the dam itself will be evaluated and advanced based on the assessed need. These projects may include decommissioning and redeveloping the existing generating station—including the water passage—and upgrading the dam. The Strathcona – Upgrade Discharge project must be completed before implementation of the following can commence:

- Strathcona - Dam Improvements – New Powerhouse; and
- Strathcona - Dam Improvements – Embankment Dam.

Name of Capital Strategy, Plan or Study:

Generation Asset Management Strategy – Penstock Recoating

Summary of Issue:

There are 67 penstocks supplying 79 units at BC Hydro's hydroelectric generating stations. Penstocks are high-value assets that convey water from reservoirs and headponds to turbines of generating units. All but one of the penstocks are entirely steel or have steel sections. Generally, the exterior and interior surfaces of the steel penstocks are coated to protect the underlying material from abrasion, corrosion, and ultimately material loss and a reduction in structural strength.

Over time, the coatings wear, degrade and fail, leading to corrosion of the underlying penstock material. Recoating of the penstock ensures that its life can be preserved. However, if the window of opportunity to recoat the penstock is missed, the underlying material will continue to corrode over time, and eventually, the penstock can no longer be used to safely convey water to the generating facility.

If the corrosion is too severe, it may not be possible to recoat the penstock, resulting in a number of issues and risks:

- Financial – A much more expensive penstock replacement and significantly longer generating unit outage would be required;
- Reliability – The asset can no longer safely convey water to the turbine forcing the generator to be taken out of service; and
- Safety and Environmental – Severe corrosion and metal loss can result in sudden failure and large uncontrolled releases of water. BC Hydro mitigates this risk by monitoring the condition of its penstocks over time and would proactively remove an asset from service if degradation became too severe.

Currently, 12 steel penstocks are between 50 and 60 years old, and 25 are more than 60 years old (of which three are no longer in service). Age is one factor but operating environment and water pressure, the quality of the coating and design factors have a larger effect on the asset health. Presently, 34 of these steel penstocks have been assessed as Poor or Unsatisfactory, primarily due to issues with the coatings, indicating there is an increased likelihood of loss of structural strength if not addressed in a timely manner.

Summary of Solution:

BC Hydro has undertaken a number of activities to better understand the condition of the penstocks and coatings. Work was undertaken to assess the health of all of BC Hydro's penstocks to establish a baseline of condition and risks. An enhanced penstock asset health methodology was developed to assess both the condition of the penstocks and the coatings. The information has been used to identify the poorest condition penstock coatings and to estimate the window of time remaining to recoat the penstocks before a replacement of the asset would be required.

As a result of this work, a number of capital projects have been identified to remediate the risks associated with the higher risk penstocks with a focus on penstock coatings. The planned scope and timing of these investments has considered factors such as:

- The need to recoat both the exterior and interior, or whether one surface is a higher priority;
- The need to recoat an entire penstock or whether only localized coating refurbishment would be sufficient;
- The opportunity to co-ordinate the investment with similar duration unit outages; and
- The operating pressure of the penstock, with higher pressure penstocks generally given higher priority for recoating.

Given the coating condition of a large number of penstocks, consideration was given to a project delivery strategy that minimizes costs, reduces quality risks and more efficiently delivers the recoating projects.

Short-Term:

The condition of assets is reviewed on a regular basis considering such factors as recurring test results, visual inspections, and detailed engineering assessments. This information is used to assess the condition of each penstock to help prepare a consolidated list across the fleet to identify the most appropriate time to address the risks while best coordinating other planned generating unit outages. Below is a list of those penstocks with higher priority requiring investment in the short-term and with capital improvement projects ongoing:

- Ash River steel penstock (external recoating);
- Bridge River 1 penstocks 1 to 4 (internal and external recoating);
- Bridge River 2 penstock 2 (internal recoating);
- Cheakamus penstocks 1 and 2 (internal and external recoating);
- Jordan River penstock (external recoating);
- Lake Buntzen 1 penstock (external recoating);
- Puntledge steel penstock (internal and external recoating of high criticality areas); and
- Wahleach penstock (internal and external recoating).

Medium-Term:

There are a number of penstock coating refurbishment projects that will need to be initiated in the medium term. The strategy and prioritization will be adjusted over time to respond to new information becoming available from penstock condition assessments. Currently, the following locations have been identified as higher risk:

- Puntledge steel penstock (remaining internal and external recoating);
- Kootenay Canal penstocks 1 to 4 (internal recoating);
- Lake Buntzen 1 penstock (internal recoating);
- Peace Canyon penstocks 1 to 4 (external recoating);
- Walter Hardman penstock (exterior recoating);
- Mica Creek penstocks 1 to 6 (targeted recoating);
- La Joie south penstock (internal recoating);
- Seton penstock (internal recoating); and
- GM Shrum penstocks 1 to 10 (internal recoating).

Long-Term:

Over the next 10 years, a number of penstock coatings will continue to degrade. Remediation of the risks associated with these assets will be required in the long-term, applying similar assessment and prioritization techniques to those outlined above.

Name of Capital Strategy, Plan or Study:

Alouette Facility Asset Plan

Summary of Issue:

The single unit, 9 MW Alouette facility is located in the Fraser Valley and was commissioned in 1928. It forms part of the Stave River system, with Stave Falls and Ruskin facilities located downstream. It consists of the Alouette Lake Reservoir, Alouette Dam, Power Tunnel from Alouette Reservoir to Stave Lake Reservoir, and Alouette Generating Station. Alouette is a Strategic[1] facility for asset management purposes and Alouette Dam is an Extreme consequence dam per the BC Dam Safety Regulation. The original dam was replaced in 1983 when the current earthfill dam was constructed immediately downstream of the original dam. Alouette Generating Station has been out of service since 2010, due to condition and reliability issues with the majority of the generating equipment; however, the water conveyance components of the facility remain an important mechanism for conveying water to the Stave Falls and Ruskin facilities.

Although Alouette Generating Station is currently out of service, investments are being made to ensure public and worker safety, water conveyance, dam safety, and environmental risks are mitigated. BC Hydro has invested over $10 million over the past 10 years. These investments include safety upgrades, and operating gate and trashrack replacements. The most significant remaining issues and risks associated with the Alouette facility include:

Dam Safety:

- Potential damage to the dam’s spillway in a major earthquake expected to occur once every 1,000 to 2,500 years that would render it unsafe for spills or drawdowns after the earthquake;
- Potential failure of the dam’s right abutment foundation in a major earthquake expected to occur once every 2,500 years, which would lead to the eventual failure of the concrete weir structures that regulate flow over the spillway;
- Expected failure of the power tunnel’s headworks and surge tower structures and ancillary equipment in an earthquake expected to occur once every 100 to 200 years, which could block the post earthquake discharge of water from Alouette Reservoir to Stave Lake Reservoir; and
- Potential rupture in a major earthquake of the seismically deficient low level outlet conduit (having unquantifiable withstand) that runs under the dam and provides environmental flows into the Alouette River downstream of the dam, which introduces the risk of internal erosion damage to the dam.

Summary of Solution:

The Alouette Facility Asset Plan presents short and long term investment strategies to mitigate risks related to dam safety, water conveyance, and the environment. In the short term, investments at Alouette will focus on addressing deficiencies related to post earthquake discharge of the reservoir and associated risks posed to the dam by ensuring post earthquake operability of the power tunnel leading from Alouette Lake Reservoir to Stave Lake Reservoir, and by upgrading or replacing the water conduit used to pass environmental flows past the dam and down the Alouette River. The medium to longer term focus will be to preserve the operational capability and infrastructure and, when appropriate, restore generation.

Short & Medium-Term:

Dam Safety:

- Headworks and surge tower seismic stability improvement; and
- Environmental flow discharge upgrade.

1 Refer to Appendix N for information on generating facility classifications.

Long-Term:

Generating Equipment:

- Powerhouse redevelopment.

The following are retained risks that are intended to be managed by completion of the Headworks and Surge Tower Seismic Stability Improvement project that is presently underway. These include:

- Seismic deficiency of the dam’s right abutment foundation and spillway weir; and
- Seismic deficiency of the dam’s spillway.

On completion, this project will provide post earthquake reservoir discharge into Stave Lake Reservoir via the power tunnel, thereby protecting these potentially damaged dam and spillway assets. Prior to the project’s completion, Alouette Lake Reservoir will be operated in a manner that provides sufficient time to provide emergency response following a major earthquake.

Name of Capital Strategy, Plan or Study:
Ash River Facility Asset Plan

Summary of Issue:

The single unit, 28 MW Ash River facility is located on Vancouver Island and was commissioned in 1959. It consists of Elsie Lake Reservoir, Elsie Main Dam, four Saddle Dams, Elsie Spillway Dam, and Ash River Generating Station. Ash River is classified as a Strategic[1] facility for asset management purposes and the dams are classified per BC Dam Safety Regulation as follows:

- Elsie Main Dam – Extreme consequence;
- Saddle Dam 1 – Extreme consequence;
- Saddle Dam 2 – Very High consequence;
- Saddle Dam 3 – Significant consequence;
- Saddle Dam 4 – Significant consequence; and
- Elsie Spillway Dam – High consequence.

Investments totaling over $5 million have been made to address safety and reliability concerns at the facility over the past 10 years. Completed capital investments have included upgrading the fire protection system, extending the life of the pressure regulating valve, improving security at Elsie Dam and upgrading the powerhouse crane.

The most significant remaining issues and risks associated with the Ash River facility include:

- Generating Equipment:
  - Asset Health Rating of Very Poor condition of the generator, elevating the reliability risks associated with the single unit and increasing the likelihood that the facility may experience an extended forced outage; and
  - Obsolete and deteriorating protection and controls and metering systems pose a reliability risk and could result in misoperation, equipment damage, and forced outages.
- Dam Safety:
  - The coatings on the steel penstock have failed which will lead to corrosion and metal loss of the underlying material, thereby reducing the life of the penstock. A finite window of opportunity exists to recoat the assets before a much more extensive replacement / refurbishment is required; and
  - The ongoing deterioration and accelerated decay of the woodstave penstock is reducing its ability to continue to safely convey water which may prematurely impact ongoing generation from the facility.

Summary of Solution:

The Ash River Facility Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed) considering factors such as condition, rate of deterioration, the operating environment and criticality.

In the short term, activities to address the risks with the steel penstock, generator, communication system, and protection and control and metering systems will be undertaken in order to address reliability and power supply risks. In the medium-term, risks with the woodstave penstock will be mitigated. In the longer-term, work on other major unit components will be undertaken in order to mitigate reliability risks.

[1] Refer to Appendix N for information on generating facility classifications.

Short-Term:

- Generating Equipment:
  - Generator upgrade; and
  - Protection and control and metering systems upgrade.
- Dam Safety:
  - Steel penstock recoat.
- Telecommunications:
  - Communication system upgrade.

Long-Term:

- Generating Equipment:
  - Turbine overhaul; and
  - Governor replacement.
- Dam Safety:
  - Woodstave penstock replacement.

Name of Capital Strategy, Plan or Study: Bridge River Facility Asset Plan

Summary of Issue:
The eight-unit, 500 MW Bridge River facility is located approximately 60 km west of Lillooet and forms part of the Bridge River system with the La Joie facility and the Seton facility located upstream and downstream, respectively. The facility consists of:
• Carpenter Lake Reservoir;
• Terzaghi Dam, which was completed in 1960;
• The four-unit, 200 MW Bridge River 1 (**BR1**) Generating Station, which was commissioned in 1954; and
• The four-unit, 300 MW Bridge River 2 (**BR2**) Generating Station, which was commissioned in 1960.
The Bridge River facility is classified as a Key[1] facility for asset management purposes and Terzaghi Dam is classified as an Extreme consequence dam per the BC Dam Safety Regulation.
BC Hydro has made a number of investments in the Bridge River facility over the past 10 years, totaling over $293 million. Investments in the generating equipment have included: BR1 Transformer replacements, BR1 Switchgear Replacement, BR1 Penstock Leak Detection, BR1 Powerhouse Piping Replacement, BR2 Unit 7 and Unit 8 Circuit Breaker replacement, BR2 Penstock Inlet Valve Hydraulic Control Upgrade, and Unit Replacement for Units 5-8. Other key investments have included: the Bridge River Town Site redevelopment and reliability upgrades of the Terzaghi Dam Spillway Gates.
The overriding concern in the Bridge River System is that of water management and operating in accordance with the water licenses that have been issued to BC Hydro. The system is heavily constrained by limits on allowable flows past Terzaghi Dam into the lower Bridge River. At present, the generating capacities of all four units at BR2 have been de-rated due to degrading equipment condition, reducing the flow of water that can be routed through that generating station and hindering BC Hydro's ability to prevent excessive flows in the lower Bridge River. This is compounded by the fact that Downton Reservoir behind La Joie Dam at the upstream end of the system has been drawn down to manage dam safety risks at that facility, removing a portion of the system's available storage buffer and flexibility. Restoring reliable generation to historic levels, at both the BR1 and BR2 generating stations, will enable more effective water management throughout the system, and mitigate reliability risks associated with lost generation.
The most significant remaining issues and risks associated with the Bridge River facility include:
• Generating Equipment:
  - BR1 generators are in Very Poor condition per the Asset Health Ratings, elevating the reliability and water management risks associated with the generating units and increasing the likelihood that the facility may experience an extended forced outage;
  - Obsolescence of the BR1 exciters, elevating the risk of forced outages; and
  - BR1 governors are in Poor condition per the Asset Health Ratings, elevating the risk of forced outages; and
• Dam Safety:
  - Failed coatings on the steel penstocks which will lead to corrosion and metal loss of the underlying material, thereby reducing the life of the penstocks. A finite window of opportunity exists to recoat the assets before a much more extensive replacement or refurbishment is required;
  - Deficiencies in the seismic withstand and operational reliability of the low level outlet gates at Terzaghi Dam, which could result in their failure to open as needed in a flood event or following an earthquake, for which the risk is managed in part by regular testing and maintenance of the gate system;

[1] Refer to Appendix N for information on generating facility classifications.

- Inadequate seepage monitoring at Terzaghi Dam to detect progression of internal erosion and piping within the foundation. Internal erosion has the potential to lead to failure at Terzaghi Dam as a result of seepage through the cut-off wall bedrock. The leakage through the cut-off has resulted in periodic sinkhole repairs;
- Deficiencies in the seismic withstand of the two intake towers on Carpenter Lake Reservoir, which would likely be damaged in an earthquake somewhat smaller than that expected to occur once every 500 years, limiting or disrupting their ability to direct water to the BR1 and BR2 powerhouses for generation and managing the reservoir level;
- Stability of the BR1 penstock slope and powerhouse foundation, especially during an earthquake, comprising a risk that slope, or powerhouse movement could cause a penstock rupture. Slope stability is a retained risk that is managed at the powerhouse with wells and sensors to control and monitor groundwater pressures, and a leak/rupture detection system on the BR1 penstocks; and
- Rock fall hazard in the Terzaghi Dam spillway chute that prevents safe entry to the spillway without significant preparatory work such as rock scaling and installation of protective structures. Lack of safe access to the spillway chute impedes the inspection, maintenance and assurance of safe condition of the spillway.

Summary of Solution:

The Bridge River Facility Asset Plan presents a strategy to replace assets on a component by component basis considering factors such as condition, rate of deterioration, the operating environment and criticality.

Investments requiring outages have been consolidated to reduce the impact on water management in the system. In the short term, the focus will be on higher priority investments required for water management and safe and reliable generation. The medium to longer-term activities will focus on the stability of the two intake towers and the replacement of major valves.

Short-Term:

- Generating Equipment:
  - BR1 generating station Unit 1-4 generators, exciters and governors replacement.
- Dam Safety:
  - BR2 interior penstock recoating;
  - BR1 interior and exterior penstock recoating;
  - BR1 slope stability improvement;
  - BR1 penstock concrete foundation refurbishment;
  - Terzaghi Dam spillway chute safe access improvements;
  - Terzaghi Dam low level outlet reliability improvements;
  - Terzaghi Dam instrumentation upgrades;
  - Terzaghi Dam downstream infill berm construction; and
  - BR1 Mitigate Surge Spill Hazard.

Medium-Term:

- Dam Safety:
  - Terzaghi Dam upstream cut-off upgrade; and
  - BR1 and BR2 intake seismic stability improvements.

Long-Term:

- Generating Equipment:
  - BR1 and BR2 major valve replacements.

Name of Capital Strategy, Plan or Study: Burrard Synchronous Condensers Station Facility Asset Plan
Summary of Issue: Burrard Thermal was a natural gas fired generating station with six 150 MW thermal generating units that were first put into operation in 1962. Since 2016, the Burrard facility has only operated as a synchronous condenser station. As a synchronous condenser station, Burrard is a major reactive power source in the Lower Mainland and is used to regulate system voltage under various system operating conditions. BC Hydro has invested over $33 million in this station and the previous operating regime as a thermal generating facility. Recent investments have been focused on sustaining reliable operations as a synchronous condenser station. The facility is over 55 years old and approaching end of life which poses system reliability, environmental, and safety risks. The most significant issues and risks associated with the Burrard Synchronous Condenser Station (**BSY**) are associated with aging infrastructure and equipment: • The synchronous condensers at BSY are at or approaching end of life. The potential failure of BSY is a transmission system reliability risk, given the reactive power capacity that BSY provides to the transmission system.
Summary of Solution: The BSY Facility Asset Plan presents an interim strategy to continue operations, maintenance, and sustaining capital to ensure reliable operation through to October 2025. In the short term, projects are staged to prioritize reliability, safety, and environmental risks. The medium to long-term strategy will be dependent on the outcome of the Burrard Synchronous Condensers Replacement Study and advancement of the Lower Mainland – Capacitive and Reactive Power Reinforcement Project. **Short-Term:** • Modify for post-generation operations: - Transmission system stability three unit reliability sustainment; - Synchronous condense control systems reliability sustainment; - Units 1 to 3 unit protection reliability sustainment; - Saltwater ducting reliability monitoring and sustainment; and - Fire protection system replacement. • Turbine hall roof upgrades. • Buntzen pumphouse maintenance. **Medium-Term to Long Term:** • Refer to the Burrard Synchronous Condensers Replacement Study Appendix K for medium to long-term considerations.

Page 1 of 1

Name of Capital Strategy, Plan or Study:

Cheakamus Facility Asset Plan

Summary of Issue:

The two-unit, 158 MW Cheakamus facility is located near Squamish and was commissioned in 1957. It consists of Daisy Lake Reservoir, Cheakamus Dam and Cheakamus Generating Station. Cheakamus is classified as a Strategic[1] facility for asset management purposes and Cheakamus Dam is classified as an Extreme consequence dam per the BC Dam Safety Regulation.

BC Hydro has made substantial progress restoring the health of this generating facility over the past 10 years through a number of investments totaling over $104 million. Investments in the generating equipment have included the turbine runner upgrades, generator replacements, powerhouse crane refurbishment, sump controls upgrade, and an improvement of the plant's fire protection and security. Investments in dam safety have included spillway gate reliability improvements.

The most significant remaining issues and risks associated with the Cheakamus facility include:

- Generating Equipment:
  - The Asset Health rating is Very Poor for the Unit 1 and Unit 2 turbine inlet valves which increases the operational risks associated with the generating units.
- Dam Safety:
  - Failed interior and exterior coatings on Unit 1 and Unit 2 penstocks, which will lead to corrosion and metal loss of the underlying material thereby reducing the life of the penstock;
  - Seepage and potential internal erosion of the dam at high reservoir levels which is currently mitigated by maintaining a reduced maximum reservoir elevation;
  - Insufficient resistance to seismic loads that may lead to failure of the dam, spillway, spillway gates and/or penstock pedestals in a major earthquake occurring, on average, about once every 1,000 years or more;
  - Residual deficiencies in the reliability of the upgraded spillway gates system, notably the lack of "black start" capability of the system's uninterruptible power supply that would restore electrical power to the gates in the event of a local blackout. The risk of the gates failing to operate as required in such events is currently mitigated by maintaining and testing back-up diesel generators on site; and
  - Potential for a landslide at the Barrier and 4th Lobe slopes to impact the dam and downstream channel.

Summary of Solution:

The Cheakamus Facility Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. In the short-term, the focus will be on higher priority investments required for safe and reliable generation that are sequenced to minimize outages. The medium to longer-term activities will focus on the dam and spillway facilities.

Short-Term:

- Generating Equipment:
  - Units 1 and 2 turbine inlet valves replacement.
- Dam Safety:
  - Units 1 and 2 penstocks recoat (interior and exterior); and
  - Concrete dam instrumentation upgrade.

[1] Refer to Appendix N for information on generating facility classifications.

Medium and Long-Term: • Dam Safety: - Spillway seismic upgrade; - Earthfill dam seepage and seismic upgrade; - Addition of penstock rupture detection system; - Penstock pedestals and slope improvement; and - Spillway gates reliability improvement. The retained risk associated with a landslide at the Barrier and 4th Lobe slopes is managed by ongoing inspection and monitoring of the slopes.

Name of Capital Strategy, Plan or Study: Cutler Hammer Exciter Risk Mitigation Review
Summary of Issue: BC Hydro conducted a fleet-wide review on Cutler Hammer excitation systems in 2014 following several exciter failures. The review identified 26 Cutler Hammer exciters in service in 11 facilities with most of the assets being put into service in the early 2000s. As part of the review, BC Hydro engaged Basler (now the owner of Cutler Hammer) to evaluate the exciter protection and control systems at G. M. Shrum and propose a method to modify the existing units to achieve faster energy dissipation after a fault to reduce the risk of catastrophic failure. The review identified a number of limitations with the exciter protection and control and remedial actions to reduce the risk of a fault resulting in an explosive failure that would pose a risk to staff. The most significant issues and risks associated with the existing Cutler Hammer excitation systems include: • Cutler Hammer exciters are not capable of discharging the supply to the generators fast enough during a fault which could result in a prolonged fault duration and significant equipment damage; and • The existing protection relays are non-redundant and do not provide adequate protection for certain failure scenarios.
Summary of Solution: BC Hydro initiated a fleet-wide program to upgrade the existing Cutler Hammer protection and control systems to address the safety risk. The new protection and control systems will reduce the duration and intensity of a fault, therefore reducing the severity of the fault and subsequent damage to the exciter and safety risk to personnel. The focus of the phase one capital investment released in fiscal 2021 is to address the immediate safety risk associated with failure of a Cutler Hammer exciter at the G.M. Shrum and Seven Mile Generating stations, which were ranked the highest priority across the BC Hydro fleet. A phase two capital project is proposed for release in fiscal 2026 to address risks with the remaining Cutler Hammer exciters within the fleet. **Short-Term:** • Cutler Hammer excitation systems upgrade at G.M. Shrum and Seven Mile facilities to address the highest safety and reliability risks across the fleet. **Medium-Term:** • Cutler Hammer excitation systems upgrade at the remaining generation stations with these assets including: Aberfeldie, Cheakamus, Lake Buntzen 1, Ladore, Strathcona, Puntledge, Wahleach, Seton and Ash River. **Long-Term:** • None.

Page 1 of 1

Name of Capital Strategy, Plan or Study:
Fort Nelson Facility Asset Plan

Summary of Issue:

The two unit 73 MW Fort Nelson facility is located 22 km from the community of Fort Nelson and was constructed in 1999 as a simple-cycle 47 MW plant and upgraded in 2012 to the current 73 MW output combined-cycle plant. Fort Nelson is not connected to the BC Hydro grid and is connected to the Alberta electric system via a transmission line. The facility is a combined-cycle power plant that uses both a gas and a steam turbine together to produce more electricity from the same fuel than a traditional simple-cycle plant as it was prior to upgrade. The Unit 1 Generator (**G1**) is run by a gas turbine. The G1 once-through-steam-generator uses the waste heat from the gas turbine to generate steam which in turn drives the Unit 2 Generator (**G2**) turbine.

The Fort Nelson facility can run in three operating modes:

i. Simple Cycle – run the G1 gas turbine only for faster start-up and ramping.
ii. Combined Cycle – run the G1 gas turbine and G2 steam turbine together for higher output and better efficiency without using extra fuel.
iii. Combined Cycle with Duct Firing – burn extra fuel using the duct burner to maximize G2’s output but at a lesser overall efficiency.

G1 can run alone without having G2 online (simple cycle operation). However, G2 can only run if G1 is online (combined cycle operation).

Over the past 10 years, over $70 million of the total $103 million in investments made at the facility have been to upgrade the simple-cycle facility to a combined cycle facility. The remaining investments have gone towards facility upgrades and targeted investments to sustain the reliable operation of the facility.

The most significant remaining issues and risks associated with the Fort Nelson facility include:

- Generating Equipment:
  - The G2 steam turbine is approaching the recommended overhaul interval which increases the reliability risk and could result in an extended forced outage resulting in a loss of generation and inability to service customers appropriately; and
  - The G1 gas turbine anti-icing system is constrained by mechanical and process control limitations which prevent optimal performance and dispatch flexibility of the system.

Summary of Solution:

The Fort Nelson Facility Asset Plan presents a strategy that initially focuses on addressing the highest priority items. Given that significant facility upgrades have occurred in the past 10 years, targeted sustainment activities are the priority at the Fort Nelson facility. In the short term, activities will address the identified risks and issues associated with the G2 turbine and addressing performance limitations with the anti-icing system. In the long-term, targeted upgrades associated with the generating assets in accordance with equipment supplier guidelines will be required to ensure optimal asset performance.

Short-Term:

- Generating Equipment:
  - Turbine (G2) refurbishment; and
  - Turbine (G1) anti-icing system upgrade.

Medium and Long-Term:

- Sustaining investments as required based on operating profile.

Name of Capital Strategy, Plan or Study:

G.M. Shrum Facility Asset Plan

Summary of Issue:

The 10-unit, 2,917 MW G.M. Shrum facility is located 23 km upstream of Peace Canyon Dam and approximately 160 km from the Alberta border. It was commissioned in stages from 1968 through 1980. It is comprised of the Williston Reservoir, W.A.C. Bennett Dam and the G.M. Shrum Generating Station. G.M. Shrum is classified as a Key[1] facility for asset management purposes and W.A.C. Bennett Dam is classified as an Extreme consequence dam per the B.C Dam Safety Regulation.

BC Hydro has made substantial progress in maintaining and improving the health of this generating facility over the past ten years through investments totaling about $580 million. Investments in the generating equipment have included replacement/refurbishment of many of the original key components, including units 1 to 5 turbine upgrade, units 1 to 4 stator replacement, increased capacity of units 6 to 8, three of four phases of transformer replacements, and station service replacement. Significant investments in dam safety have included: stabilization of the rock slope above the dam’s spillway, resurfacing and other upgrades to the concrete lining of the spillway chute, upgrades to the rip rap on the upstream face of the dam, and upgrades to the dam’s core including rehabilitation of instrumentation wells.

The most significant remaining issues and risks associated with the G.M. Shrum facility include:

- Generating Equipment:
  - Asset Health Rating of Poor condition of eight of the 30-unit transformers, combined with emerging deficiencies on some of the unit transformers, poses an operational reliability risk; and
  - Asset Health Rating of Poor condition of the unit 5 and unit 6 generators, elevating the reliability risks associated with the units and increasing the likelihood of an extended forced outage.
- Dam Safety:
  - Deficiencies in the operational reliability of the spillway gates that could result in their failure to operate as needed during high inflows, the risk of which is currently managed by regular testing and maintenance of the gates system;
  - Unknown but presumably deteriorating condition of now-disused low-level outlets situated within the construction-period diversion tunnels, failure of which would lead to uncontrolled release of Williston Reservoir;
  - Deteriorating, non-functioning and disused sluice gates below the spillway gates, failure of which would lead to uncontrolled release of Williston Reservoir;
  - Continued erosion of the rock face above the spillway approach channel which is beginning to undermine the storage location of the spillway’s maintenance stoplogs, the risk of which is managed by ongoing surveillance of the slope and progression of erosion;
  - Presumed seismic deficiency of the spillway’s structures and electrical and mechanical equipment (presently the subject of a Dam Safety Investigation);
  - Failed coatings of the intake operating gates and intake maintenance gates, which could lead to corrosion and metal loss of the underlying material, thereby reducing the life of the gates;
  - Deficiencies in the hydraulic systems of the intake operating gates that could result in operational reliability risks; and
  - Degrading condition of various coatings in the water passages, including penstocks, scroll case, and coupling chamber, which could lead to corrosion and metal loss of the underlying material, thereby reducing the life of the assets.

[1] Refer to Appendix N for information on generating facility classifications.

Summary of Solution:

The G.M. Shrum Facility Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed) considering factors such as condition, rate of deterioration, the operating environment and criticality. In the short-term, projects are staged to prioritize investments in key generating equipment and high-risk dam safety components. In the medium to long-term, projects are staged to address the next highest risks in the generating equipment, including upgrade of units 9 and 10, and improve reliability and seismic performance of the flood discharge system.

Short-Term:

- Generating Equipment:
  - Unit 5 and Unit 6 generator refurbishment;
  - Unit 9 and Unit 10 circuit breaker replacement;
  - Unit 3A, 3B, and 10A transformer replacement; and
  - Unit 2, 5, 6, 7, and 8 Pauwels transformer life extension.
- Dam Safety:
  - Spillway gate reliability upgrade;
  - Sealing of the low-level outlets;
  - Recommissioning or sealing the spillway sluice gates;
  - Intake operating gate and intake maintenance gate refurbishment; and
  - Intake operating gate hydraulic upgrade.

Medium-Term:

- Generating Equipment:
  - Unit 9 and Unit 10 turbine overhaul; and
  - Unit 9 generator refurbishment.
- Dam Safety:
  - Spillway seismic upgrade;
  - Spillway approach channel upgrade; and
  - Water passage refurbishment.

Long-Term:

- Generating Equipment:
  - Unit 7 and Unit 8 generator refurbishment.
- Dam Safety:
  - Spillway gate electrical and mechanical improvements.

Name of Capital Strategy, Plan or Study:

Hugh Keenleyside Facility Asset Plan

Summary of Issue:

The Hugh Keenleyside facility is located on the Columbia River, about 8 km upstream of Castlegar. Hugh Keenleyside Dam was commissioned in 1968 under the terms of the Columbia River Treaty to provide storage for flood control and to maximize hydro generation in both the United States and Canada. The major components of the Hugh Keenleyside facility include the Arrow Lakes Reservoir, Hugh Keenleyside Dam comprising an earthfill dam and a concrete gravity dam with spillway and low-level outlets, and a Navigation Lock to provide a passage for commercial and recreational marine traffic through the dam. The Hugh Keenleyside facility does not have a generating station, but a power canal on the left abutment diverts water from the Arrow Lakes Reservoir to the Arrow Lakes Generating Station owned by Columbia Power and the Columbia Basin Trust. Hugh Keenleyside Dam is classified as an Extreme consequence dam per the BC Dam Safety Regulation.

BC Hydro has made substantial progress restoring the health of this facility over the past 10 years through investments totaling over $100 million, including an upgrade of the navigation lock controls, a major spillway gate reliability upgrade, replacement of the debris boom, dam instrumentation improvements, and a facility security system upgrade.

The most significant remaining Dam Safety risks associated with the Hugh Keenleyside facility include:

- Spillway and low-level outlet concrete erosion which, if not addressed, could impact the operation of the facility and the maintenance and inspection of the gates. There is also a risk that the eroded zones could grow in size during high water discharges, resulting in an extended outage of the spillway. These risks are currently managed by having implemented modified discharge operating procedures to slow the damage and by periodic underwater inspections;
- Degrading condition of the foundation drains and instrumentation, where non-functioning drains would reduce the stability of the dam. This risk is managed by continuous monitoring of the uplift pressures under the dam and the condition of the instruments;
- Potential post-earthquake deformation of the concrete spillway piers, which would render the low-level outlet gates inoperable and limit the post-earthquake reservoir discharge capability;
- Moderately deficient seismic withstand of the earthfill dam relative to its Extreme consequence classification, estimated to be equivalent to an earthquake expected to occur once every 8,000 years.
- Degrading condition of the coatings on the navigation lock gates, which will lead to corrosion and metal loss of the underlying material, thereby reducing the life of the asset;
- Deterioration of the service water piping;
- Degradation of main deck gantry crane, which is required to perform maintenance on the spillway and low-level outlets; and
- Degradation of spillway and low-level outlet stoplogs condition, which are required for isolation and to perform maintenance on the spillway and low-level outlets.

Summary of Solution:

The Hugh Keenleyside Facility Asset Plan presents a strategy to mitigate risks related to safe storage and reliable passage of water under normal and unusual (e.g., flood and earthquake) conditions. The short-term investments include upgrading the concrete discharge structures to ensure continued safe and reliable water discharge, upgrading the main deck gantry crane, and preserving the critical navigation lock infrastructure. The medium-term investments focus on addressing the seismic withstand deficiencies of the concrete dam (i.e., deformation of the spillway piers), upgrading the instrumentation and monitoring of water pressures under the dam, enhancing the operability of the select components of the discharge system and addressing the seismic withstand deficiencies of the earthfill dam.

Short-Term:

- Spillway and low-level outlet concrete upgrade;
- Service water piping replacement;
- Navigation lock gates recoating; and
- Main deck gantry crane upgrade.

Medium and Long-Term:

- Concrete dam seismic stability upgrade;
- Dam foundation drains and instrumentation replacement;
- Spillway and low-level outlet stoplogs upgrade; and
- Earthfill dam seismic stability upgrade.

Name of Capital Strategy, Plan or Study: John Hart Facility Asset Plan
Summary of Issue: The three-unit, 135 MW John Hart facility is located on Vancouver Island and was originally constructed in 1947. John Hart forms part of the Campbell River system, with Ladore and Strathcona facilities located upstream. The facility includes the John Hart Reservoir, John Hart Dam, and the John Hart New Generating Station. The original John Hart Generating Station was developed in 1947 and permanently ceased operation when the John Hart New Generating Station was placed into service in 2018. John Hart is classified as a Strategic[1] generating facility for asset management purposes and the John Hart Dam is classified as an Extreme consequence dam per the BC Dam Safety Regulation. The John Hart facility has received a significant level of investment in the last 10 years, with over $1 billion of investments made to construct a new power intake, power tunnel, underground generating station, and environmental flow bypass, as well as provide interim upgrades for the most pressing dam safety issues. Prior to making this investment, in 2009 BC Hydro initiated the Campbell River Systems Engineering Assessment and investigated the full range of options for the development of the river system in order to identify how investment should be prioritized to deliver safe and sustainable long-term management of the river system assets. The most significant remaining issues and risks at the John Hart facility include: • Dam Safety: - Susceptibility of the dam to fail in an earthquake expected to occur, on average, once every 500 years; - Deficiencies in the operational reliability and seismic withstand of the spillway gates system, for which the risk is currently managed by regular testing and maintenance of the system; - Potential for flow imbalance due to interruption of generation at John Hart while generation continues at Ladore Generating Station upstream, for which the risk has been partially addressed by improvements implemented within the generating station redevelopment with the residual risk being managed through controls to automatically shut down generation at Ladore in the event of a shutdown at John Hart; and - Unreliable water level gauges downstream of John Hart Dam.
Summary of Solution: Following the recent redevelopment of the generating station, this facility's investment strategy exclusively targets the existing Dam Safety risks identified above. Capital upgrade projects are currently underway or scheduled to commence in the short term to address these risks. **Short-Term:** • Dam Safety: - Upgrades to the John Hart Dam to address seismic, flow imbalance and spillway gate reliability issues; and - Upgrades to the Campbell River water level monitoring system.

[1] Refer to Appendix N for information on generating facility classifications

Name of Capital Strategy, Plan or Study: Jordan River Facility Asset Plan
Summary of Issue: The single unit, 167 MW Jordan River facility is located on the southern part of Vancouver Island, approximately 40 km west of Sooke at the end of a radial transmission line. The facility was redeveloped in 1971. It consists of: • Bear Creek Reservoir; • Jordan Diversion Reservoir; • Elliot Headpond; • Bear Creek Dam; • Jordan Diversion Dam; • Elliot Dam; and • Jordan River Generating Station. Jordan River is classified as a Strategic[1] Facility for asset management purposes and the dams are classified per BC Dam Safety Regulation as follows: • Elliott Dam - Very High consequence; • Jordan Diversion Dam - Very High consequence; and • Bear Creek Dam - Low consequence. In the past 10 years, Jordan River has benefited from a number of capital investments totaling approximately $25 million. Recent equipment investments have included fire protection system upgrades and recoating a significant section of the penstock. Other recent investments have included the acquisition of properties downstream of Jordan River. These acquisitions are part of the effort to reduce public exposure in downstream areas that could be in inundated in the event of a major earthquake. The most significant remaining issues and risks associated with the Jordan River facility include: • Generating Equipment: - Governor and pressure reducing valve obsolescence leading to system reliability and maintainability issues; - Mitigating reliability risks related to the 13 kV circuit breaker system; and - Deteriorating condition of the powerhouse fire protection system which could lead to localized damage of the piping and a subsequent failure to operate normally when required. • Dam Safety: - The coatings on a number of sections of the penstock have failed which will lead to corrosion and metal loss of the underlying material, thereby reducing the life of the penstock. A finite window of opportunity exists to recoat the assets before a much more extensive replacement or refurbishment is required; - Susceptibility of the Low consequence Bear Creek Dam to failure in a small to moderate earthquake; - Obstruction of the Bear Creek Spillway that can cause outflows to back up against the downstream “toe” of the dam and cause potential damage; and - Susceptibility of Jordan Diversion Dam and Elliott Dam to failure in an earthquake expected to occur, on average, approximately once in every 500 years, for which the risk is currently being managed as described above.

[1] Refer to Appendix N for information on generating facility classifications

Summary of Solution:

The Jordan River Facility Asset Plan proposes a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed) considering factors such as condition, rate of deterioration, the operating environment and criticality.

In the short-term, activities to address the risks with the governor, 13 kV circuit breaker system and fire protection system. In the medium to long term, activities will be started to address Bear Creek Dam and spillway pending the recommendations from a forthcoming strategic review of these assets. In the longer term, investments in the aging generating equipment as well as refurbishment of the Jordan Diversion Dam low level outlets may be required.

Short-Term:

- Generating Equipment:
  - Upgrade of the governor and pressure reducing valve system;
  - Upgrades to the 13 kV circuit breaker system; and
  - Upgrades to the powerhouse fire protection system.
- Dam Safety:
  - Penstock recoating.

Medium-Term:

- Dam Safety:
  - Potential upgrades to the Bear Creek spillway.

Long-Term:

- Generating Equipment:
  - Turbine overhaul;
  - Generator overhaul; and
  - Exciter upgrade.
- Dam Safety:
  - Jordan Diversion Dam low level outlets refurbishment; and
  - Potential seismic upgrade at Bear Creek Dam.

Name of Capital Strategy, Plan or Study:

Kootenay Canal Facility Asset Plan

Summary of Issue:

The four-unit, 580 MW Kootenay Canal facility is located on the Kootenay River approximately 20 kilometres upstream of its confluence with the Columbia River near the city of Castlegar. The facility was commissioned in 1975 and consists of Kootenay Canal, which diverts water from the Kootenay River into a concrete lined forebay, Kootenay Canal Dam and Kootenay Canal Generating Station. Kootenay Canal is classified as a Key[1] facility for asset management purposes and Kootenay Canal Dam is classified as a Very High consequence dam per the BC Dam Safety Regulation.

BC Hydro has made effective progress restoring the health of several components of this generating facility over the past 10 years through investments totaling over $36 million. Investments in the facility equipment have included upgrades to the intake gantry and the powerhouse cranes and replacement of the station service transformer. Dam safety investments have included the installation of a membrane liner within the forebay to seal off leakage through joints between the concrete slabs, instrumentation improvement in the Power Intake concrete blocks and in the slopes located south and west of the main dam structure above the penstocks. The most significant remaining issues and risks associated with the Kootenay Canal facility include:

- Generating Equipment:
  - All four generators and protection and control equipment have an Asset Health Rating of Poor which could impact the reliability of the generating equipment and result in loss of generation; and
  - Deficiencies in the existing fire protection system that have increased the risk of system failure due to accelerated corrosion and potential rupture of the piping.
- Dam Safety:
  - Failing and leaking joints between the canal's concrete slabs—upstream of the remediated forebay—that could eventually allow seepage to undermine the slabs. This risk is currently managed by regular visual inspections of the canal's concrete liner and embankments and by measurements of seepage through collection weirs; and
  - Failed coatings on the penstocks and intake operating gates that will lead to corrosion and metal loss and reduce the life of the penstocks and the gates.

Summary of Solution:

The Kootenay Canal Facility Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed) considering factors such as condition, rate of deterioration, the operating environment and criticality.

In the short term, investments to address the risks associated with the protection and control equipment as well as the generators will be undertaken. In the medium to long term, investments are proposed to address risks with anticipated degradation of major equipment, auxiliary equipment and water passage infrastructure.

Short-Term:

- Generating Equipment:
  - Unit 1 to 4 unit protection upgrade;
  - Fire detection and alarm system replacement;
  - Unit 1 to 4 generators refurbishment; and
  - Unit 1 to 4 controls modernization.

[1] Refer to Appendix N for information on generating facility classifications

- Dam Safety:
  - Canal concrete liner slab joints upgrade; and
  - Unit 1 to 4 intake operating gate refurbishment.

Medium & Long-Term:

- Generating Equipment:
  - Fire protection piping replacement;
  - Unit 1 to 2 transformer replacement;
  - Unit 1 to 4 turbine overhaul;
  - Tailrace gantry crane upgrade;
  - AC station service upgrade; and
  - Unit 1 to 4 cooling water piping replacement.
- Dam Safety:
  - Unit 1 to 4 penstocks recoat;
  - Headworks structure upgrade; and
  - Penstock Pedestals Upgrade.

Name of Capital Strategy, Plan or Study: La Joie Facility Asset Plan
Summary of Issue: The single unit, 22 MW La Joie Facility is located near the village of Goldbridge approximately 100 km west of Lillooet. It consists of: • Downton Reservoir; • La Joie Dam; and • La Joie Generating station. La Joie is a Strategic[1] facility for asset management purposes and La Joie Dam is classified as an Extreme Consequence dam per the BC Dam Safety Regulation. Investments in the past 10 years have been relatively modest at $15.2 million, mostly to address reliability concerns with the discharge facilities (gates, valves and conduits). In 2014, BC Hydro lowered the Downton maximum normal reservoir operating level from an elevation of 749.8 million to an elevation of 734.0 million to mitigate the risk of a dam failure in the event of a seismic event, and to minimize the impacts downstream. This is a temporary measure until the dam's deficiencies can be mitigated through a planned project to upgrade the dam. The most significant remaining issues and risks associated with the La Joie facility include: Generating Equipment: • The generating unit protection and controls system is original, obsolete and difficult to maintain. Unreliable protection could lead to extended outages or damage to equipment if it fails to operate; • The governor per the Asset Health Rating is in poor condition primarily due to age, decreasing reliability and a lack of spare parts. There is a risk that the governor could fail, which would lead to a long forced outage and a loss of generation. The La Joie governor is unique in that it also controls the Pressure Regulating Valve (**PRV**) and a governor failure may make the PRV inoperable. Either the generating unit or the PRV need to be operable to manage the Downton Reservoir and keep it below the lower maximum operating level imposed as an interim risk mitigation measure until the La Joie Dam deficiencies are addressed; • The PRV is a butterfly style valve that was installed in 1956. It has suffered from severe cavitation and fatigue damage. Due to the deteriorated condition of the PRV, there is a risk it may fail which would lead to a long, forced outage, a loss of generation and limit our ability to manage the Downton Reservoir; • The generator is original and per the Asset Health Rating is in poor condition. Due to its age, it has an increasing risk of a failure that would result in a loss of generation; • The turbine per the Asset Health Rating is in poor condition. Due to age and wear on the turbine components, there is a risk the runner will fail, which could lead to a long, forced outage resulting in lost generation; and • The exciter is original and per the Asset Health Rating is in poor condition. Due to age, there is a risk it could fail which would lead to a medium-length forced outage and a loss off generation. Dam Safety: • La Joie Dam is constructed of uncompacted rockfill with a shotcrete face. The shotcrete face cracks as the underlying rockfill settles over time, requiring regular maintenance to manage seepage under normal operating conditions. During an earthquake, the dam could move and settle, creating larger cracks in the shotcrete face and leading to leakage through the dam. Excessive leakage through the dam could wash out the toe material resulting in dam failure and an uncontrolled release of the reservoir. If insufficient storage is available in the downstream Carpenter Reservoir, a failure of La Joie dam could result in overtopping of the Terzaghi earth filled dam and a cascading dam failure that would have severe impacts to communities downstream on the Bridge and Fraser Rivers;

[1] Refer to Appendix N for information on generating facility classifications

- Due to the design and deteriorated condition of the intake tower, a major earthquake expected to occur once every 1,000 years could cause the intake tower to collapse, blocking the intakes and preventing the passage of water through the powerhouse or hollow cone valves to the Middle Bridge River; and
- The south conduit passes water to the generating unit and PRV. It is in very poor condition per the Asset Health Rating due to coating failure, design limitations, and the presence of active corrosion. If left unmitigated there is a risk of structural failure of the conduit. This would lead to it being taken out of service resulting in a long, forced outage, a loss of generation and a reduced ability to manage the Downton Reservoir level.

Summary of Solution:

The La Joie Facility Asset Plan presents a strategy to replace assets on a component-by-component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment and criticality. In the short term, the focus will be on higher priority investments that are required for dam safety and water management issues as well as issues with controls and protection. In the medium-term, focus will shift to major components on the generating equipment.

Short-Term:

Dam Safety:

- Upgrades to La Joie Dam and intake tower.

Generating Equipment:

- Unit protection and control upgrades; and
- Governor and PRV replacement.

Medium and Long-Term:

- Generator, turbine, governor replacement; and
- Turbine inlet valve replacement.

Name of Capital Strategy, Plan or Study: Ladore Facility Asset Plan
Summary of Issue: The two-unit, 47 MW Ladore facility is located on Vancouver Island and was commissioned in 1958. It was built as part of the Campbell River development and forms part of the Campbell River system with the Strathcona facility and John Hart facility located upstream and downstream, respectively. The facility consists of the Lower Campbell Lake Reservoir, the Ladore Dam, the Loveland Bay Saddle Dam, the Big Slide and McIvor Bay Natural Barriers and the Ladore Generating Station. The facility is classified as a Strategic[1] Facility for asset management purposes and the dams are classified per the BC Dam Safety Regulation as follows: • Ladore Dam - Extreme consequence; • Loveland Bay Saddle Dam - Significant consequence; and • Big Slide Saddle Dam - Significant consequence. In 2009 BC Hydro initiated the Campbell River Systems Engineering Assessment and investigated the full range of options for the development of the river system in order to identify how investment should be prioritized to deliver safe and sustainable long-term management of the river system assets. In the last 10 years, a number of capital investments totaling $29 million have been made at the Ladore facility. Recent investments have included the replacement of the intake gates, upgrade of the oil containment and replacement of the powerhouse and tailrace cranes. The most significant remaining issues and risks at the Ladore facility include: • Generating Equipment: - The protection and controls equipment is over 55 years old, with deteriorated electro-mechanical relays with no failure detection system which pose a risk of misoperation leading to increased equipment damage and extended outage; and - Asset Health Rating of Poor condition of the Unit 1 and Unit 2 generators, transformers and turbines increase the reliability risks of both generating units and could result in an extended forced outage. • Dam Safety: - Inadequate seismic withstand of the spillway gates and hoist structures which could result in a loss of control of the reservoir following a major earthquake expected to occur, on average, once every 1200 years; - Unreliable operability of the Low-Level Outlet that has not been in operation for over 40 years due to concerns over debris jamming the Hollow Cone Valve; and - Deficiencies in the operational reliability of the spillway gates that could result in their failure to open as needed in a flood event.
Summary of Solution: The Ladore Facility Asset Plan presents a component-by-component investment strategy to address the identified risks and overall condition of the facility while considering factors such as condition, rate of deterioration, the operating environment, and criticality. In the short term, activities to address the risks with the spillway gates, communication system, protection and control systems, and the transformers and generators will be started to mitigate reliability and power supply risks. In the medium to longer term, activities to address risks associated with the turbine and governor will be undertaken.

[1] Refer to Appendix N for information on generating facility classifications

Short-Term:

- Generating Equipment:
  - Address protection and control issues; and
  - Procurement of a spare transformer.
- Dam Safety:
  - Seismic and reliability upgrades of Ladore Dam spillway gate systems; and
  - Decommissioning or restoration of the Low-Level Outlet and Hollow Cone Valve.
- Telecommunications:
  - Communication system upgrade.

Medium-Term:

- Generating Equipment:
  - Generator upgrade;
  - Turbine overhaul; and
  - Governor replacement.

Name of Capital Strategy, Plan or Study: Coquitlam Buntzen System Facility Asset Plan
Summary of Issue: The single unit, 60 MW Lake Buntzen facility is located in Metro Vancouver and was commissioned in 1951. It is part of the Coquitlam-Buntzen system, which consists of Coquitlam Reservoir and Dam, Coquitlam diversion tunnel, Buntzen Lake Reservoir and Dam, and Lake Buntzen 1 and 2 Generating Stations. Lake Buntzen is classified as a Strategic[1] facility for asset management purposes. Coquitlam Dam is an Extreme consequence dam and Lake Buntzen Dam is a Significant consequence dam per the BC Dam Safety Regulation. The original Lake Buntzen 1 Generating Station first went into service in 1903. In 1951 the original generating units were replaced with a single 60 MW unit that continues to operate today. The three unit Lake Buntzen 2 Generating Station was built in 1913, and permanently ceased operation 2013. The original Coquitlam Dam, constructed in 1905, was replaced by a second dam in 1914. This second dam was found to be severely deficient under earthquake loading, and a new embankment dam was constructed on the downstream toe of the second dam in 2008. The second dam remains in place, but is not relied upon to retain the reservoir. BC Hydro improved the health of the Coquitlam-Buntzen system through a number of investments in the last 10 years totaling over $31 million. Investments in generating equipment have included a turbine upgrade and powerhouse crane upgrade. Dam safety investments have included the construction of a new Coquitlam Dam, upgrades to the Coquitlam Dam low level outlet gates, and an upgrade to the Lake Buntzen spillway. The most significant remaining issues and risks associated with the Coquitlam-Buntzen system include: Generating Equipment: • Asset Health Rating of Poor for the Lake Buntzen 1 generator, which elevates the reliability risks associated with the single generating unit and increases the likelihood that the facility may experience an extended forced outage. Dam Safety: • Poor condition of the Coquitlam tunnel gates, a failure of which would result in the loss of control of water conveyance from Coquitlam Reservoir to Buntzen Lake Reservoir; • Failed interior and exterior coatings on the Lake Buntzen 1 penstock which will lead to corrosion and metal loss of the underlying material, thereby reducing the life of the penstock. A finite window of opportunity exists to recoat the asset before a much more extensive refurbishment or replacement is required; • Potential failure of the Coquitlam tunnel's inlet and outlet portals during an earthquake expected to occur, on average, once every 100 to 200 years; • Potential failure of the Coquitlam Low Level Outlet structure in an earthquake expected to occur, on average, once every 3,500 to 5,000 years; and • Insufficient capacity of the Lake Buntzen 1 spillway that increases the risk of overtopping Buntzen Dam and flooding Lake Buntzen 1 Generating Station, a risk that BC Hydro is currently accepting but managing through increased surveillance when reservoir elevations are high.

[1] Refer to Appendix N for information on generating facility classifications

Summary of Solution:

The Coquitlam-Buntzen Facility Asset Plan presents a strategy to replace assets on a component-by-component basis (i.e., undertake discrete investments as needed), considering factors such as asset condition, rate of deterioration, the operating environment, and criticality.

In the short-term, the focus will be on risks associated with the ability to transfer water between Coquitlam Reservoir and Lake Buntzen Reservoir, as well as reliability of the Lake Buntzen 1 penstock and generating unit. In the medium to longer-term, investments will continue to address the risks associated with the Coquitlam tunnel inlet portal seismic withstand as well as addressing the flood discharge capability of Lake Buntzen Dam.

Short-Term:

Generating Equipment

- Lake Buntzen 1 generator replacement.

Dam Safety:

- Coquitlam tunnel gates refurbishment;
- Lake Buntzen 1 exterior penstock recoat; and
- Lake Buntzen 1 interior penstock recoat.

Medium and Long-Term:

Dam Safety:

- Coquitlam tunnel inlet portal seismic upgrade; and
- Lake Buntzen Dam flood discharge capability improvement.

The risks associated with the low seismic withstand of the Coquitlam Tunnel outlet portal, and the Coquitlam Dam Low Level Outlet structure are monitored and will be retained as the consequences are expected to be low.

Name of Capital Strategy, Plan or Study: Mica Facility Asset Plan
Summary of Issue: The six unit, 2780 MW Mica facility is located on the Columbia River north of the town of Revelstoke. It was constructed under the terms of the Columbia River Treaty. The dam was completed in 1973, two generating units were installed and commissioned in 1976, two more in 1977 and the final two in 2015. The facility includes Kinbasket Lake Reservoir, Mica Dam and Mica Generating Station. Mica is classified as a Key[1] facility for asset management purposes and Mica Dam is classified as an Extreme consequence dam per the BC Dam Safety Regulation. Approximately $842 million has been invested at Mica over the past ten years, $626 million of which was to upgrade the gas insulated switchgear system and commission the fifth and sixth generating units. Investments in the generating equipment have also included a Unit 1 transformer replacement and battery and charger replacement. Dam Safety investments within this period included installation of new instrumentation and rehabilitation/sealing of construction era instrumentation (vertical movement gauges) to improve Mica Dam instrumentation and safety. The most significant remaining issues and risks associated with the Mica facility include: • Generating Equipment; - Asset Health Rating of Poor of the original unit transformers, line reactors and Unit 1 and 2 turbines increases the reliability risk and may result in forced outages; - Obsolescence of the original Unit 1 to 4 circuit breakers, exciter controls and governor controls increases the reliability risk and may lead to forced outages; - Deteriorated condition of the Heating, Ventilation and Air Conditioning systems increases the safety risk in the underground powerhouse as these systems are relied upon to move air through the facility in emergency situations; and - Deteriorated condition of the Unit 1 and 2 cooling water piping increases the risk of piping failure resulting in damage to the facility or equipment. • Dam Safety: - Inadequate seismic withstand of the flood discharge systems (spillway and outlet works) which could result in a loss of control of the reservoir following a major earthquake expected to occur, on average, once every 2000 to 3000 years; - Deficiencies in the operational reliability of the spillway gates that could result in their failure to open as needed in a flood event, the risk of which is currently managed by regular testing and maintenance of the existing systems; - Deterioration of the water passage protective coatings will lead to corrosion and metal loss of the underlying material thereby reducing the life of the penstock; and - Potential failure of the nearby Dutchman’s Ridge and Little Chief Slide into Kinbasket Reservoir under unusual loads (e.g., earthquake or extreme precipitation), which could lead to overtopping of the dam. This risk is managed through a sustained program of slope surveillance and monitoring.

1 Refer to Appendix N for information on generating facility classifications

Summary of Solution:

With the completion of Units 5 and 6 in 2015, Mica is continuing a period of planned refurbishment of the original four units that were installed and commissioned in the 1970s. The Facility Asset Plan proposes a component-by-component replacement strategy to sustain operation at the Mica Facility by mitigating the risk of failure of individual assets on an as-needed basis (e.g., condition, rate of deterioration, operating environment, and criticality).

Investments in the short-term will focus on the highest priority safety and reliability risks in the powerhouse that can be mitigated without an extended outage and on addressing high consequence risks associated with current spillway and outlet works deficiencies.

Work in the medium to long-term will be undertaken with continued focus on equipment that is in poor condition but requires longer duration outages, as well as works to maintain or improve the stability of Dutchman's Ridge and Little Chief Slide.

Short-Term:

- Generating Equipment:
  - Unit 1 to 4 unit transformer replacements;
  - Unit 1 to 4 exciter controls, governor controls and unit protection replacement;
  - Reactor replacement;
  - Heating, Ventilation and Air Conditioning system upgrades; and
  - 600 V switchgear and essential electrical bus upgrades.
- Dam Safety:
  - Flood discharge facilities seismic and reliability upgrades;
  - Refurbish intake gantry crane;
  - Little Chief slope inclinometer installation;
  - Units 1-4 intake gate hydraulic power unit and controls replacement; and
  - Water passage coatings restoration.

Medium-Term:

- Generating Equipment
  - Unit 1 and 2 turbine overhauls;
  - Unit 1-4 circuit breaker and iso-phase bus replacement; and
  - Unit 1 and 2 cooling water piping replacement.
- Dam Safety:
  - Dutchman's Ridge and Little Chief Slide: slope stability improvements or measures to mitigate impacts of failure.

Long-Term:

- Generating Equipment
  - Unit 3 and 4 turbine overhauls; and
  - Unit 3 and 4 cooling water piping replacement.

Name of Capital Strategy, Plan or Study: Peace Canyon Facility Asset Plan
Summary of Issue: The four-unit, 700 MW Peace Canyon facility is located 6 km upstream of Hudson's Hope and 23 km downstream of the G.M. Shrum Generating Station on the Peace River. It was placed into service in 1980 and is comprised of the Dinosaur Lake Reservoir, the Peace Canyon Dam, and the Peace Canyon Generating Station. Peace Canyon is classified as a Key[1] generating facility for asset management purposes and Peace Canyon Dam is classified as an Extreme consequence dam per the BC Dam Safety Regulation. BC Hydro has actively maintained the health of this important generating facility over the past 10 years though a number of investments totaling over $20 million. Investments in the generating equipment include replacement of the generator stators and turbine overhauls. The most significant remaining issues and risks associated with the Peace Canyon facility include: • Generating Equipment: - Failed coatings of the scroll case which will lead to corrosion and metal loss of the underlying material, thereby reducing the life of the scroll case. A finite window of opportunity exists to re-coat the asset before a much more extensive refurbishment or replacement would be required; - Increased risk of water leakages from deteriorated condition of the high and low pressure piping systems that may cause damage to critical and sensitive equipment; and - Asset Health Rating of Poor condition of Unit 1 to 4 Exciters. • Dam Safety: - Deficiencies in the operational reliability of the spillway gates that could result in their failure to open as needed in a flood event, the risk of which is currently managed by regular gate testing and maintenance as required; - Continuing erosion of rock at the rim of the plunge pool downstream of the spillway structure that could eventually progress upstream to the toe of the spillway and threaten that structure's stability, currently managed by the performance of underwater inspections following spills; - Potential failure of the dam in a major earthquake expected to occur, on average, once every 4,200 years; - Diminishing efficiency of the dam's foundation drainage systems that could eventually result in insufficient stability of the dam structure, which is currently managed by continuous monitoring of uplift pressures and drain cleaning as required; and - Failed coatings of the penstock which will lead to corrosion and metal loss of the underlying material, thereby reducing the life of the penstock. A finite window of opportunity exists to re-coat the asset before a much more extensive refurbishment or replacement would be required.

1 Refer to Appendix N for information on generating facility classifications

Summary of Solution:

The Peace Canyon Facility Asset Plan presents a strategy to replace assets on a component-by-component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. Capital upgrade projects are carefully planned in coordination with G.M. Shrum as operations at G.M. Shrum can be restricted when Peace Canyon units are out of service. In the short-term, projects are staged to prioritize reliability investments in key generating equipment. In the medium to long term, projects are staged to restore water passage coatings, improve the reliability of the flood discharge system and improve the seismic withstand of the Peace Canyon Dam.

Short-Term:

- Generating Equipment:
  - Unit 1 to 4 Exciter Replacement; and
  - High and Low Pressure Piping Replacement.
- Dam Safety:
  - Pressure cleaning of the dam's foundation drains.

Medium-Term:

- Generating Equipment:
  - Scroll case Recoating.
- Dam Safety:
  - Spillway gates control upgrade;
  - Peace Canyon Dam seismic upgrade;
  - Dam foundation drain rehabilitation; and
  - Penstock Recoating

Long-Term:

- Dam Safety:
  - Spillway gates electrical and mechanical upgrades.

The risk that the spillway plunge pool may continue to erode during major spill events is currently being managed by monitoring the progression of the eroded area. Capital investment is not planned at this time; however, future work may be required to ensure that the spillway structure does not become undermined.

Name of Capital Strategy, Plan or Study:
Puntledge Facility Asset Plan

Summary of Issue:

The single unit, 24 MW Puntledge facility is located near the City of Courtenay on Vancouver Island. The facility is comprised of the Comox Lake Reservoir, Comox Dam, Puntledge Dam and the Puntledge Generating Station. Both dams were constructed in 1912 and the generating station was constructed in 1955. Puntledge is classified as a Strategic[1] Facility for asset management purposes. The dams are classified as follows per the BC Dam Safety Regulation:

- Comox Dam - Extreme consequence; and
- Puntledge Dam - Very High consequence.

Over the past 10 years, BC Hydro has undertaken capital investments totaling over $38 million at Puntledge in order to mitigate known public safety risks associated with the water level gauges, public warning system, and flow control system and to address penstock reliability issues.

The most significant remaining issues and risks associated with the Puntledge facility include:

- Generating Equipment:
  - The intake operating gates and pressure release valves are subject to a number of issues which can impact their reliable operation resulting in an elevated public safety risk due to unexpected changes in downstream water releases;
  - Asset Health Rating of Poor condition of the generator which increases the reliability risk and increases the likelihood that the facility may experience an extended forced outage; and
  - The coating of the steel penstock has failed along the majority of its length leading to corrosion and metal loss of the underlying material thereby reducing the life of the penstock. A finite window of opportunity exists to recoat the asset before a much more extensive rehabilitation or replacement is required.
- Dam Safety:
  - The spillway operating gates at Comox Dam have deficiencies in reliability that could render them inoperative when needed during high inflows and could lead to overtopping of the dam and abutments, the risk of which is currently managed by regular testing and maintenance of the existing systems;
  - The Comox and Puntledge Dams have seismic deficiencies that, in the event of an earthquake expected to occur, on average, once every 1000 years, could lead to their failure and consequent downstream impacts;
  - The right abutment of Comox Dam is susceptible to erosion during low probability flood conditions which could result in a breach and uncontrolled release of Comox Lake Reservoir;
  - The ongoing deterioration and accelerated decay of the woodstave penstock increases the risk that the asset will no longer be able to safely convey water; and
  - Potential overtopping of Comox Dam in the event of the extreme design flood expected to occur, on average, once every 1000 years.

Summary of Solution:

The Puntledge Facility Asset Plan proposes a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed) considering factors such as condition, rate of deterioration, the operating environment and criticality.

[1] Refer to Appendix N for information on generating facility classifications

In the short-term, activities to address the issues with the steel penstock and flow control and water level monitoring systems will be undertaken as these have been identified as being higher priority public safety risks. In the medium term, activities will be started to address the condition of the generating unit and the seismic withstand of the Puntledge Dam in order to mitigate reliability and dam safety risks, respectively. In the longer term, seismic withstand of the Comox Dam will be addressed along with the condition of the woodstave penstock.

Short-Term:

- Generating Equipment:
  - Steel penstock recoating.
- Dam Safety:
  - Flow control improvements; and
  - Upgrades to the water level monitoring and public safety warning systems.

Medium-Term:

- Generating Equipment:
  - Generator refurbishment; and
  - Turbine refurbishment.
- Dam Safety:
  - Puntledge Dam structure seismic upgrade.

Long-Term:

- Dam Safety:
  - Woodstave penstock replacement; and
  - Comox Dam seismic upgrades.

At this time, no investment is proposed to address the overtopping risk of Comox Dam structure due to measures within ongoing and planned projects to mitigate the downstream safety risk.

Name of Capital Strategy, Plan or Study: Revelstoke Facility Asset Plan
Summary of Issue: The five-unit, 2,368 MW Revelstoke facility was built in 1984 and is located on the main stem of the Columbia River near the town of Revelstoke. The facility includes the Revelstoke Reservoir, the Revelstoke Dam, and the Revelstoke Generating Station. The first four generating units went into service in 1984, the fifth unit went into service in 2011, and there is space for a sixth unit. Revelstoke is classified as a Key[1] facility for asset management purposes and Revelstoke Dam is classified as an Extreme consequence dam per the BC Dam Safety Regulation. BC Hydro has made substantial progress in maintaining the health and increasing the capacity of this generating facility over the past 10 years through several investments totaling over $70 million. Investments in the generating equipment have included the installation of generating Unit 5, upgrades to instrumentation monitoring at Downie Slide, 731 Block Stability Improvement, rehabilitation/sealing of embankment dam construction era instrumentation (vertical movement gauges), replacing 600 V switchgear equipment, replacing unit protection equipment and upgrades to the powerhouse crane. The most significant remaining issues and risks associated with the Revelstoke facility include: • Generating Equipment; - Asset Health Rating of Poor of the Unit 2 to 4 generators increases the reliability risk and may result in long unit outages; - Configuration and expected deterioration of the iso-phase bus increases the reliability risk associated with unit outages; - Obsolescence of the Unit 1 to 4 exciter and governor controls increases the reliability risk and may result in unit outages; and, - Asset Health Rating of Poor of seven of the 12 Unit 1 to 4 transformers increases the reliability risk and may result in long unit outages. • Dam Safety: - The potential for Downie Slide, a slow-moving land mass on the Revelstoke Reservoir, to slide into and block the Columbia River, which is managed under the terms of the water license by maintaining an extensive network of drainage throughout the extent of the slide and by continuously monitoring the slide's movements and pore water pressures; - Potential failure of portions of the rock slope at the dam's left abutment that could impact the penstocks and powerhouse or damage the rock anchors that stabilize larger masses of rock on the slope, which is currently managed by monitoring and surveillance; - Inadequate reliability and seismic withstand of the flood discharge (spillway) system that may impact our ability to manage water in a controlled manner during high inflow events or in the aftermath of an earthquake, for which the risk is currently managed by regular gate testing and maintenance; and - Damaged and unreliable instrumentation in the concrete blocks, and insufficient instrumentation to monitor uplift pressures that may impact our ability to collect reliable uplift information that is needed to ensure that the concrete blocks have adequate safety factors against sliding and overturning.
Summary of Solution: The Revelstoke Facility Asset Plan presents a strategy to replace assets on a component-by-component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. Implementing the investment strategy at Revelstoke facility is at the early stages which include refurbishing the original equipment and infrastructure. Adding the sixth generating unit is contingent upon long-term system capacity requirements.

[1] Refer to Appendix N for information on generating facility classifications

In the short-term, projects are staged to prioritize investments required for safe and reliable generation and to leverage facility growth potential to support meeting system capacity needs. Timing of the addition of the sixth unit and coordination with other Revelstoke projects creates risk due to limited physical space in the powerhouse constraining the ability to carry out several major projects at once. Investments to monitor and manage risks related to landslides are ongoing and proposed to continue through the medium term.

Short-Term:

- Generating Equipment:
  - Unit 1 to 4 generator stator replacements;
  - Refurbish intake and tailrace gantry cranes;
  - Databus system replacement.
  - Unit 1 to 4 transformer replacements;
  - Perimeter security upgrades; and
  - Addition of the sixth generating unit (continuation subject to outcome of 2021 Integrated Resource Plan).
- Dam Safety:
  - Flood discharge (spillway) system reliability improvements;
  - Left Bank slope stability improvements to reduce the risk of rockfall and protect the rock anchors in the slope from damage (ongoing project);
  - Downie Slide instrumentation replacements to ensure continued monitoring of water pressures and deformations in the slope in accordance with the dam's water license (ongoing project); and
  - Installation of new piezometers in the concrete blocks to ensure that Revelstoke Dam will have an adequate number of piezometers that effectively and reliably monitor the uplift pressures under the concrete dam (ongoing project).

Medium-Term:

- Generating Equipment:
  - Addition of the third section of gas insulated switchgear bus; and
  - Unit 1 to 4 exciter and governor controls replacement.
- Dam Safety:
  - Remediation of the slope drainage system at Downie Slide in the timeframe when its effectiveness is expected to diminish, in accordance with the dam's water license.

Long-Term:

- Generating Equipment:
  - Unit 1 to 4 turbine overhauls; and
  - Unit 1 to 4 circuit breaker replacement.
- Dam Safety:
  - Unit 1 to 4 water passage coating restoration.

Name of Capital Strategy, Plan or Study:
Seton Facility Asset Plan

Summary of Issue:

The single unit, 44 MW Seton facility is located near Lillooet and was commissioned in 1956. It consists of:

- Seton Lake;
- Seton Dam;
- Left Bank Dyke;
- Cayoosh Diversion Tunnel;
- Seton Canal; and
- Seton Generating Station.

Seton is classified as a Strategic[1] facility for asset management purposes and Seton Dam is classified as a High consequence dam per the BC Dam Safety Regulation.

BC Hydro has made a number of investments over the past 10 years totaling more than $23 million. The most significant investments have included the refurbishment of the power canal lining and upgrades to the spillway gates, replacement of the Governor and Unit Protection.

The most significant remaining issue and risks associate with Seton facility include:

- Generating Equipment:
  - The generator is rated as Poor based on the Asset Health Rating. Due to the condition the generator it will likely experience an increasing risk of a failure that could result in a loss of generation and high flows in the Seton River; and
  - The turbines are in Poor condition per the Asset Health Rating. The turbines have experienced additional wear, cracking, and excessive leakage through the wicket gates which increases reliability risk and may result in an increased number of forced outages.
- Dam Safety:
  - The coating on the penstock has failed which will lead to corrosion and metal loss of the underlying material, thereby reducing the life of the penstock. A finite window of opportunity exists to re-coat the asset before a much more extensive rehabilitation or replacement is required;
  - Cracks and leaks in the concrete lined canal could lead to a failure of the lining and breach of the canal, the risk of which is being managed by regular inspections and repairs to slow deterioration of the canal lining’s overall condition;
  - Inability to close the headworks gates and shut off flow in the event of a canal failure, resulting in an uncontrolled release of water from Seton Lake, with current risk management as per the preceding item; and
  - Uncertainty and expected deficiency of the seismic resistance of various civil assets (headworks operating gates, forebay, dam, left dyke, aqueduct, canal) which could lead to an uncontrolled release of Seton Lake. These structures are estimated to be capable of withstanding an earthquake expected to occur once every 1500 to 5000 years, depending on the asset.

[1] Refer to Appendix N for information on generating facility classifications

Summary of Solution:

The Seton Facility Asset Plan presents a strategy to replace assets on a component-by-component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. The ability to take outages at the facility can be limited given the important role that the unit plays with respect to water conveyance. The timing of investments that require unit outages have been coordinated to minimize the impact on water management.

In the short-term, the focus will be on higher priority investments that are required for water management as well as safe and reliable generation. Investments are sequenced to minimize the number and duration of outages required. The medium to longer-term activities will focus on the canal and headworks gates and seismic issues.

Short-Term:

- Generating Equipment:
  - Turbine overhaul; and
  - Generator replacement.
- Dam Safety:
  - Penstock coating replacement;
  - Headworks gates upgrades; and
  - Canal refurbishment.

Medium-Term:

- Dam Safety:
  - Canal and aqueduct seismic upgrades; and
  - Left Bank Dyke seismic upgrades.

Long-Term:

- Dam Safety:
  - Dam seismic upgrades.

An investigation is planned to assess and obtain a better understanding of the seismic performance of various civil assets at the facility relative to the criteria for a High consequence dam.

Name of Capital Strategy, Plan or Study: Seven Mile Facility Asset Plan
Summary of Issue: The four-unit, 814 MW Seven Mile facility is located on the Pend d'Oreille River in southern British Columbia, upstream of Waneta Dam and downstream of Boundary Dam which is owned by Seattle City Light. The facility includes the Seven Mile Reservoir, the Seven Mile Dam, and the Seven Mile Generating Station. The first unit at Seven Mile Generating Station went into service in 1979, with two additional units installed in 1980 and the fourth unit installed in 2003. Seven Mile is classified as a Key[1] facility for asset management purposes and Seven Mile Dam is classified as an Extreme consequence dam per the BC Dam Safety Regulation. BC Hydro has invested over $36 million in this facility over the past ten years. Investments in the generating equipment have included the excitation system replacement, Units 1 to 3 stator re-wedging, Units 1 to 4 partial discharge monitoring and Units 1 to 3 protection upgrades. Dam safety investments have included reservoir slopes instrumentation upgrades and general dam safety improvements. The most significant remaining issues and risks associated with the Seven Mile facility include: • Generating Equipment: - Poor Asset Health Rating of some of the generating equipment including unit controls, exciter transformers and unit transformers could impact the reliability of the generating equipment and result in loss of generation; - Unit 1 to 3 turbines are 37 to 38 years old and have never undergone a major intervention. The latest engineering inspection identified excessive band seal erosion and runner cavitation on these units. Furthermore, due to lack of wicket gate friction devices on these turbines, there is a risk of an undetected shear pin failure event which would result in damage to the wicket gates and unit outages; - Poor Asset Health Rating of the powerhouse, tailrace gantry and intake gantry cranes that could impact the reliability of the cranes and their lifting capabilities; - Poor Asset Health Rating of the cooling water piping that has increased the risk of piping failure; and - Deficiencies in the existing fire alarm and fire protection systems that have increased the risk of system failure due to accelerated corrosion and potential rupture of the piping. • Dam safety: - Deficiencies in the reliability of the flood discharge (spillway) facilities that could lead to a failure of the system to operate on demand during high inflows (a flood or spurious release from Boundary Dam upstream) and result in significant damages to the dam and powerhouse, the risk for which is currently managed through regular gate testing and maintenance; - Deteriorating performance of the dam's drainage system that is continually monitored but, if not remediated, would eventually compromise the dam's stability; and - Failed coatings on the intake operating gates will lead to corrosion and metal loss and reduce the life of the gates.

[1] Refer to Appendix N for information on generating facility classifications.

Summary of Solution:

The Seven Mile Facility Asset Plan presents a strategy to replace assets on a component-by-component basis (i.e., undertake discrete investments as needed) considering factors such as condition, rate of deterioration, the operating environment and criticality.

In the short-term, the focus will be on higher priority investments required for safe and reliable generation that are sequenced to minimize outages. Medium term activities include those related to maintaining reliable operation of the flood discharge systems. In the long term, activities will continue to focus on investments required to address safety risks and reliability risks for equipment in poor condition.

Short-Term:

- Generating Equipment:
    - Unit 1 to 4 exciter transformer replacement;
    - Powerhouse crane upgrade;
    - Unit 1 to 3 turbine upgrade;
    - Fire alarm system replacement;
    - Unit 1 to 4 controls replacement; and
    - Unit 1 transformer replacement.
- Dam Safety:
    - Flood discharge systems reliability improvements

Medium & Long-Term:

- Generating Equipment:
    - Unit 1 to 3 cooling water piping replacement;
    - Unit 2 to 3 transformers replacement;
    - Fire protection piping replacement;
    - Unit 1 to 3 generators replacement; and
    - Intake gantry crane upgrade.
- Dam Safety:
    - Foundation drains replacement; and
    - Intake operating gate refurbishment.

Name of Capital Strategy, Plan or Study: Shuswap Facility Asset Plan
Summary of Issue: The two-unit Shuswap Falls powerhouse is located on the Shuswap River approximately 35 km east of Vernon. It consists of: • Shuswap Falls Generating Station (Unit 1 - 3 MW, Unit 2 - 3.5 MW); • Wilsey Dam; • Sugar Lake Dam; and • Sugar Lake Reservoir. The Sugar Lake Reservoir is operated on an annual fill and release cycle, with the majority of inflows resulting from spring snowmelt and seasonal storm events. The downstream Shuswap generating facility operates as a run-of-river facility passing the Sugar Lake Dam discharges and local inflows. The Shuswap facility is classified as an Available[1] energy facility for asset management purposes and represents less than 0.1 per cent of BC Hydro's total hydroelectric generation capability. Plant output supplies a portion of the local area load, but the facility is not designed to run without system frequency support provided by the 138 kV lines that tie into the Lumby substation. The Shuswap Generating Station has been in service for over 90 years, is near end of life and provides limited system benefit (e.g., dependable capacity, voltage support, local load support). Unit 1 has been out of service since 2013. There are concerns around the structural condition of Wilsey Dam, and ongoing commitments to evaluate capital solutions to provide fish passage upstream of Wilsey Dam. Over the next 10 years, the total cost to refurbish the Shuswap facility is expected to exceed $50 million, including $28 million to refurbish Wilsey Dam, $11 million to construct a fish channel, and upwards of $20 million to renew the generating assets. The most significant remaining issues and risks associated with the Shuswap facility include: Generating Equipment: • Unit 1 was taken out of service and there a no current plans to reinvest in the unit; and • Unit 2 generating equipment ranges from poor to good condition, with major equipment like the governor and exciter being in the best condition and the generator being in the worst condition. Dam Safety: • Sugar Lake Dam has potential seepage issues at the right and left abutment. The abutment is the structure that joins the dam to natural ground. The left abutment is a sand and gravel embankment with two concrete cut-off walls founded, at least in part, on bedrock, and designed to impede the flow of water. The right abutment is an embankment on till with a concrete cut-off wall and a cut-off trench filled with soil. Internal erosion of the Sugar Lake Dam abutments is suspected. Erosion that is left unabated could result in abutment failure which would result in an uncontrolled release from the reservoir; • Wilsey Dam is considered to be in poor to unsatisfactory condition based on the most recent semi-annual inspection of the dam. The strength of the concrete is potentially less than originally designed, and there is extensive cracking and seepage through joints in the main arch dam. Sections of the plug dam are suffering from significant concrete spalling, thereby reducing the mass weight of the plug. The loss of concrete in the plug dam is at the point of undermining the post-tensioning anchor heads. Failure of the dam would result in significant environmental impacts due to the uncontrolled release of sediment into the river, and the facility's proximity to a Department of Fisheries and Oceans Canada fish hatchery two kilometres downstream. There is also potential for loss of worker life in the downstream area in the event of dam failure; and

1 Refer to Appendix N for information on generating facility classifications.

- For the past 12 years, the Wilsey Dam Fish Passage Committee has been working through BC Hydro's Fish Passage Decision Framework in an effort to evaluate opportunities for salmon reintroduction upstream of Wilsey Dam. In addition to re-establishing upstream fish habitat, fish passage represents an opportunity to improve the relationship with local First Nations and gain support with the regional district and local interest groups who have been working on this process for over 12 years. Delay in demonstrating progress is a reputational risk that may harm relationships and cause a loss of trust with First Nations and regional interest groups.

Summary of Solution:

Based on preliminary financial analysis and considering the strategic significance of this facility within a growing portfolio of fleet wide risks, the leading alternative for Wilsey Dam and Generating Station is to decommission the facility. The key components of adopting this long-term strategy are:

- Decommissioning of the powerhouse and all generating equipment;
- Provision of fish passage via decommissioning of Wilsey Dam and site restoration to natural state; and
- Sustained investment in Sugar Lake Dam to ensure continued safe operation.

This strategy is considered to provide the best value approach for BC Hydro and ratepayers and will provide lasting social and community benefits.

Short-Term:

- None.

Medium and Long-Term:

- Sugar Lake abutment upgrades.

Name of Capital Strategy, Plan or Study: Strathcona Facility Asset Plan
Summary of Issue: The two-unit 64 MW Strathcona facility is located on Vancouver Island and was constructed in 1958 (Unit 1) and 1968 (Unit 2). Strathcona forms part of the Campbell River system, with Ladore and John Hart facilities located downstream. The facility includes the Upper Campbell Reservoir, the Strathcona Dam, Crest Creek Diversion Dike, and the Strathcona Generating Station. Strathcona is classified as a Strategic[1] Facility for asset management purposes. Per the BC Dam Safety Regulation: • Strathcona Dam is rated as an Extreme consequence dam; and • Crest Creek Diversion Dike is rated as a Significant consequence dam. In 2009 BC Hydro initiated the Campbell River Systems Engineering Assessment and investigated the full range of options for the development of the river system in order to identify how investment should be prioritized to deliver safe and sustainable long-term management of the river system assets. Remediation of seismic concerns may mean that the generating facility cannot continue to operate in its current location. This still requires extensive investigation; however, the level of investment in the generating equipment has been limited, while the overall strategy is clarified. Over the past 10 years, $20 million of the total $30 million in investments made at the facility have been to implement intake tower seismic upgrades with the remaining investments going towards the intake gates, one of the generators and turbine inlet valves. The most significant remaining issues and risks associated with the Strathcona facility include: • Generating Equipment: - Asset Health Rating of Very Poor condition of the Unit 1 generator increases the reliability risk and could result in an extended forced outage resulting in a loss of generation and inability to maintain necessary water conveyance past the facility. • Dam Safety: - Expected poor post-seismic performance of the embankment dam after an earthquake occurring, on average, about once every 500 years; - Insufficient seismic withstand of the intake tower and the water conduit and penstock that pass under the dam to the powerhouse, raising concerns for their failure in an earthquake occurring, on average, about once every 500 to 1,000 years, resulting in seepage through the dam fills and potential dam failure; - Deficiencies in the operational reliability of the spillway gates that could result in their failure to open as needed in a flood event; - Insufficient seismic withstand of the spillway gates and hoist structures that, in an earthquake occurring, on average, about once every 1,000 years, could fail and result in a loss of containment and/or control of the reservoir; and - Inability to draw down the reservoir to a sufficiently low elevation following a major earthquake, as required by the expectedly poor post-seismic performance of the dam (described above).
Summary of Solution: The Strathcona Facility Asset Plan presents a strategy that initially focuses on addressing the highest priority water conveyance and dam safety items. The strategy to be taken for upgrades to the dam and ancillary flow control structures is described within the Campbell River Systems Engineering Assessment which is referenced above and has its own summary within Appendix K. Limited investments in the existing generating equipment will be considered on a component-by-component basis (i.e., undertake discrete investments, as needed), considering factors such as condition, rate of deterioration, the operating environment and criticality.

[1] Refer to Appendix N for information on generating facility classifications.

In the short-term, activities will address the identified risks and issues associated with the communication system, reservoir discharge capability, and generating units, in order to address immediate high priority dam safety and reliability risks, respectively. In the medium term, the focus will remain on water conveyance and addressing the seismic withstand risks associated with the dam. It is possible that the solution required to remediate the seismic issues associated with the dam may result in an inability to continue generation within the existing powerhouse. If this is the case, in the long term, opportunities to redevelop the generating station will be investigated.

Short-Term:

- Generating Equipment:
  - Generator (G1) refurbishment.
- Dam Safety:
  - Upgrade of the reservoir discharge facilities to provide sufficient operational reliability, required seismic withstand, post-earthquake drawdown capability, and capability to provide compensatory flows in the event of lost or discontinued generation.
- Telecommunications:
  - Communication system upgrade.

Medium-Term:

- Dam Safety:
  - Embankment dam seismic upgrades; and
  - Possible decommissioning of the intake tower, water conduit and penstock under the dam and concomitant decommissioning of the generating station or reducing the generating station to a non-operational station.

Long-Term:

- Generating Equipment:
  - Potential redevelopment of the Strathcona generating station.

Name of Capital Strategy, Plan or Study:

Wahleach Facility Asset Plan

Summary of Issue:

The single unit, 61 MW Wahleach facility is located in the Lower Mainland and was commissioned in 1952. It consists of the Jones Lake Reservoir, Wahleach Dam, Boulder Creek Diversion Dyke, Jones Lake Intake structure, and a water conveyance tunnel and penstock leading to the Wahleach Generating Station. Wahleach is classified as a Strategic[1] facility for asset management purposes and Wahleach Dam is classified as a Very High consequence dam per the BC Dam Safety Regulation.

BC Hydro has maintained the health of the Wahleach facility through a number of investments in the past 10 years totaling over $66 million. Investments have been focused on generating equipment, which included penstock inlet valve, governor, exciter, protection and control, transformer, switchgear, and cooling water replacements, and a fire protection system upgrade.

The most significant remaining issues and risks associated with the Wahleach facility include:

Generating Equipment:

- Asset Health Rating of Poor for the generator, which elevates the reliability risks associated with the single unit and increases the likelihood that the facility may experience an extended forced outage; and
- The coatings on the penstock and tunnel steel liner have failed which will lead to corrosion and metal loss of the underlying material, thereby reducing the life of the penstock. A finite window of opportunity exists to recoat the assets before a much more extensive refurbishment or replacement is required.

Dam Safety:

- Potential defects in the seepage control sheet piles at Wahleach Dam that could lead to erosion of dam or foundation materials and risk of dam failure. This risk is being managed by monitoring seepage through instrumentation and weekly inspections, and a response plan is in place in the event that any sign of significant seepage through the dam is observed;
- Potential failure of the intake gates at Jones Lake during a major earthquake occurring, on average, about once every 4,800 years, which would prevent the closure of the water passage and cessation of flows to what would likely be a damaged generating station and could result in the inundation of adjacent utility and transportation corridors;
- Dewatering of the tunnel has the potential to destabilize the unlined vertical shaft and can result in significant rock fall from the shaft. This risk is being managed by procedures and equipment protections which reduce the frequency and rate of dewatering; and
- Potential slope failure at Four Brothers Mountain that could result in the loss of the Wahleach facility and impact adjacent utility and transportation corridors.

Summary of Solution:

The Wahleach Facility Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. In the short-term, the focus will be on higher priority investments required for safe and reliable generation that are sequenced to minimize outages, as well as improving seismic withstand of water retention structures and control devices. The medium to longer term investments will focus on controlling seepage to ensure dam stability and addressing rockfall issues that can occur when the tunnel vertical shaft is dewatered.

[1] Refer to Appendix N for information on generating facility classifications.

Short-Term:

Generating Equipment:

- Generator refurbishment; and
- Penstock and tunnel liner coatings replacement.

Dam Safety:

- Intake Tower and gates seismic upgrade

Medium and Long Term:

Dam Safety:

- Dam foundation seepage control upgrade; and
- Possible unlined tunnel vertical shaft protection from rock fall.

The potential for a slope failure at Four Brothers Mountain is a retained risk, with no practicable means available to reduce or eliminate it. BC Hydro has implemented an ongoing surveillance program to identify changes in the slope's behaviour and to provide warning of impending instability.

Name of Capital Strategy, Plan or Study:

Whatshan Facility Asset Plan

Summary of Issue:

The Whatshan facility consists of the Whatshan Generating Station and the Whatshan Lake Reservoir impounded by the Whatshan Dam and a saddle dam. An intake structure on the east shore of the reservoir conveys water to the generating station via a 3.6 km partially lined tunnel/penstock. The single unit, 55 MW Whatshan generating station is located about 130 km east of Vernon on the west shore of the Lower Arrow Lake Reservoir near Needles, B.C. The facility was originally developed in 1951 and rebuilt in 1953 following a rock and mudslide which destroyed the original powerhouse. The second powerhouse was replaced by the existing powerhouse in 1972. The current powerhouse was placed at an elevation 12 m higher than the earlier ones due to the raising of Arrow Lakes after the completion of the Hugh Keenleyside Dam in 1968.

BC Hydro has invested approximately $12 million at Whatshan over the past 10 years, $6 million of which was to provide burial protection to a former Oatscott Reserve burial site and $3 million to replace the unit transformer.

The most significant remaining issues and risks associated with the Whatshan facility include:

- Generating Equipment:
  - Asset Health Rating of Poor of the original governor increases the reliability risk and may result in forced outages; and
  - Asset Health Rating of Fair of the original exciter system and lack of spare part availability and original equipment manufacturer support increases the reliability risk and may result in forced outages;
- Dam Safety:
  - There is uncertainty regarding the adequacy of seepage control provisions in the left abutment embankment and under the main dam. A dam safety investigation project is planned to investigate the potential piping/internal erosion risks at Whatshan Dam and to identify the seepage control measures required to address the potential dam safety concerns; and
  - Excessive leakage from the tunnel increases the risk of further deterioration of the tunnel liner, high water pressure in the rock slope and possible slope failure. Failure of the rock slope could damage the switchyard and powerhouse. This risk is currently being managed through seepage monitoring and inspections of the slope and the tunnel.

Summary of Solution:

The proposed strategy for the Whatshan facility is to make modest life extension and equipment replacement investments in order to continue to maintain and operate the facility over the long-term. A component-by-component strategy to maintain generation and water passage is proposed to upgrade/refurbish existing equipment at end-of-life over the next 20 years.

Over the short-term, the focus is on the highest priority safety and reliability risks in the powerhouse, such as replacing the governor system and restoring the coating on the turbine inlet valve. Work in the medium term will be undertaken to address the seepage issue under the main dam and to upgrade the tunnel lining. In the long-term, the exciter system will be replaced due to end of life and potential reliability risk and forced outage risk.

Short-Term:

Generating Equipment:

- Unit 1 governor replacement; and
- Turbine inlet valve coating restoration.

Medium-Term:

Dam Safety:

- Seepage control mitigation to eliminate seepage and potential erosion under the main dam; and
- Tunnel lining upgrade to reduce seepage which could lead to slope instability above the powerhouse.

Long-Term:

Generating Equipment:

- Unit 1 exciter replacement.

Name of Capital Strategy, Plan or Study:
Abbotsford Area Study

Summary of Issue:

The Abbotsford area is supplied by a 230 kV and 60 kV transmission system and the following four substations:

- Mount Lehman has a capacity of 100 MVA and was built in 2007;
- Gloucester has a capacity of 25 MVA and was built in 2002;
- Clayburn has a capacity of 180 MVA, and was built in 1984; and
- Sumas Way has a capacity of 55 MVA and was built in 1977.

The four substations supply the entire load in the study area which extends from about 248 St in Langley to Sumas Prairie east of the City of Abbotsford, and from the Fraser River to the Canada/U.S. border. The Abbotsford area has approximately 60,000 customers and a peak load of 333 MVA in fiscal 2020. The present area firm capacity is 360 MVA. In the last 10 years, the area load has grown by approximately 1.3 per cent each year. In fiscal 2020, the actual demand was approximately 333 MVA.

The City of Abbotsford, the largest municipality in this area, has a population of over 130,000. It is the largest municipality in the Fraser Valley Regional District and the fifth largest municipality in British Columbia.

BC Hydro has made investments in this area in the last 20 years totaling over $65 million. The latest investments have included the construction of two substations: Mount Lehman substation and Gloucester substation, together with the decommissioning of the old Abbotsford substation.

The most significant issues and risks remaining in the Abbotsford area include:

- Clayburn substation has feeder sections that were designed to be compact in size and at present are safety risks for workers due to limited clearance between energized equipment and ground. This risk is currently partially mitigated through physical barriers and warning signs; however, workers are unable to work on the equipment safely and efficiently without taking extended customer outages. As a result, some maintenance work at the substation cannot be completed; and
- At the Sumas Way substation, all of the equipment in the 25 kV switchyard is in poor condition. The metalclad feeder sections have arc flash hazards. Due to this safety concern, workers are restricted from entering the feeder section buildings while the equipment is energized.

Summary of Solution:

The strategy for this area is to mitigate the above reliability and safety risks while continuing to provide a reliable supply to the customers. BC Hydro has developed alternatives that upgrade the area supply in coordination with the need to retire equipment in poor condition, and to address existing safety risks at Clayburn and Sumas Way substations. The coordination will avoid stranded investments in asset replacement projects to sustain the existing system. The solution alternatives consider a number of factors, including:

- The present capacity and future load growth in the area;
- The health of the assets at area substations, and their expected degradation overtime;
- Opportunities to utilize capacity at neighboring substations;
- The timing of future projects at area substations combined with the need to retain adequate overall area capacity; and
- The need to develop the sequencing of projects in a way that minimizes/ avoids stranded investments.

Short and Medium-Term:

- Expand Mount Lehman capacity from 100 MVA to 150 MVA;
- Address the safety risks associated with Clayburn by decommissioning the unsafe feeder section with a new feeder section meeting all the present safety standards and retrofitting the other feeder section; and
- The completion of the above will allow offload Clayburn load to Mount Lehman and offload Sumas Way load to Clayburn and decommission Sumas Way. Upon completion, there will be a significant improvement in the overall equipment condition and reliability, the safety risks will be mitigated, and the area will have sufficient capacity to accommodate future load growth in the area.

Long-Term:

In the longer term, it is expected that a component replacement strategy will be implemented at the various substations to address risks with discrete assets as these degrade over time. In addition, growth in the area will continue to be monitored, to determine whether additional capacity is required.

Name of Capital Strategy, Plan or Study:

Analog 4W Inventory Study

Summary of Issue:

BC Hydro is using Analog Private Lines (**APL**) provided by TELUS for Teleprotection, Supervisory Control And Data Acquisition, telemetry, alarms and mobile radio backhaul. BC Hydro uses 175 analog lines for a total annual recurring cost of approximately $1,700,000.

TELUS has announced its intent to end this service by 2022 because of the system's age and the unavailability of spare parts with which to maintain the system. This discontinuation would require BC Hydro to migrate to alternative technologies. BC Hydro must migrate the circuits to new services prior to the discontinuation of the APL service.

Although TELUS has indicated it is willing to be flexible with its planned discontinuation date to accommodate BC Hydro's complex migration, there is a risk that failed APL circuit would not be repairable, which would lead to an extended outage to the service. Depending on the nature of the failed circuit, there could be safety or operational consequences.

Transmission Voltage Customers and Independent Power Producers also use APL services to support their interconnections with BC Hydro.

Summary of Solution:

A number of potential alternatives to APL were identified in this study, including cellular, satellite, private radio systems, and digital leased services from a carrier. The study recommends migrating the circuits off the APL services onto one of the alternatives.

Short-Term:

- Initiate a project to migrate the circuits from APL onto alternative services; and
- Work with Interconnections to identify Transmission Voltage Customers and Independent Power Producers using APL service, and initiate cutover projects with the third-parties.

Medium-Term:

- Complete migration project.

Long-Term:

No long-term capital investments are identified in this study. The alternative solution will be maintained under the Telecom maintenance work plan and may be at higher cost than current APL services.

Page 1 of 1

Name of Capital Strategy, Plan or Study: Asset Management Strategy - Protection and Control (P&C)
Summary of Issue: P&C Systems provide critical support to the primary circuit elements of the BC Hydro Transmission System by preserving the integrity and life of this equipment, maintaining overall system reliability, ensuring worker and public safety and enabling the gathering and storing or operational data. Historically, the majority of P&C equipment was comprised of older electro-mechanical type protective relay devices and later solid state type protection and control devices. While these legacy technologies are still prevalent on our system for protecting power system assets, when possible, they are replaced by modern micro-processor based equipment. This modern equipment provides additional functionality and data availability to improve operational visibility and control and improved protection capabilities. The use of micro-processor based equipment also enables the implementation of a number of advanced applications to improve the reliability and performance of the power delivery system (i.e., Volt-Var Optimization). Criticality of P&C asset failures varies depending on the type and location of the protected equipment and the type and location of the P&C asset. Impacts of P&C asset failures can be critical and can result in significant system or customer outages, and possible public and worker safety risk. The most significant issues and risks associated with the P&C assets include: • Lack of Original Equipment Manufacturer support for most legacy P&C equipment due to advanced age; • Risks of complete failure associated with poor health condition of older P&C equipment; • Increased corrective work and cost for emergency repair / replacement; • Constantly evolving and expanding compliance requirements impact operating budgets that have remained fixed; • Proportionally increasing risk of noncompliance with the expanding compliance requirements; • Specialized skill set requirements for staff; • Inaccuracies and inadequate availability of inventory data limits effective planning capabilities; • Existing control buildings often lack the required space to accommodate modern solutions that apply standards for increased capacity and added redundancy; and • Cyber Security, Compliance, and System Risk Management
Summary of Solution: Projects are planned for the sustainment of the P&C system assets by considering asset condition, function and their criticality for meeting power system reliability and safety requirements. To address the above issues and risk the following staging of investments is planned: **Short-Term:** Address the most critical elements of the P&C system: • Replace the Remote Terminal Units (**RTU**) at the following stations: Kennedy, Savona, Harewood, Sakunka, and Taylor; • Replace the Digital Fault Recorders (**DFR**) at the following stations: Malaspina, Dunsmuir, Clayburn, Nelway and Natal; • Replace Control Systems at GM Shrum and Williston susbstations and the Capacitor Bank Control System at American Creek substation; • Ensure compliance with Mandatory Reliability Standards, including CIP version 7; and • Continue work on pilot project initiated at Kent substation to apply and test new architecture for the protection and control modernization program, which is expected to improve the delivery of future P&C projects and could change the current relay sourcing strategy.

Medium-Term:

Replacement of end-of-life P&C assets will continue with a focus on the highest risk assets including remaining legacy models of protection relays, RTUs, and DFRs.

- Replace DFRs at the Seven Mile, Glenannan, Minette, Telkwa and Vaseux Lake substations;
- Replace RTUs at Maple Ridge, Foot Hills, Rainbow and Horseshoe Bay;
- Evaluate Kent Protection and Control Modernization project to initiate a program of projects to modernize small and medium sized distribution substations; and
- Projects may also be developed to comply with new Mandatory Reliability Standards.

Long-Term:

In the long-term, the P&C systems will need to continue be replaced and modernized to align with industry advances that bring additional safety, reliability and operational cost benefits, and to address asset health and end of life. The redundancy designed into the system is expected to also allow for the replacement of primary and secondary systems as they fail to maximize asset life with no impact on system reliability.

Name of Capital Strategy, Plan or Study:

Asset Management Strategy – Lines – Section 2.1.4 – Conductors

Summary of Issue:

BC Hydro has approximately 19,300 circuit-km of overhead transmission conductors. The average age of conductors on the transmission system is 45 years. The objective of the conductor strategy is to achieve a life of 80 years for transmission circuits while operating at design load capacity.

Overall, conductor condition is determined by regular inspections and failure analysis. Systematic sampling is also used for analytical condition assessments, by removing short segments of conductor for laboratory testing. When defects are identified, capital projects are initiated considering an integrated approach, and factoring in the nature of the defect, site conditions, overall condition of the line and system needs.

BC Hydro's overhead transmission line conductors can be classified in two main types: aluminum conductor steel-reinforced (**ACSR**), which is the industry standard and comprises the majority of installed conductors; and copper, which is obsolete for use as conductor, in poor condition, and is being replaced with ACSR. There are some situations where other types of conductor are used on the BC Hydro transmission system: for example, all-aluminum conductor, all-steel conductor, and aluminum conductor - carbon fibre core due to specific technical requirements such as loading or long span crossings.

Since fiscal 2010, approximately 150 km of copper conductor has been replaced, including recent projects for circuits 60L02, 60L03, 60L18, and 60L19. However, approximately 300 circuit km of copper conductor remain in the BC Hydro Transmission system. Based on existing data, the majority of transmission ACSR conductor is in good or satisfactory condition and there are no major capital improvements expected in the short-term.

The risks and issues associated with overhead conductors include:

- Condition – Degradation can occur from age and stresses such as wind, ice, lightning, thermal loading, corrosion, mechanical damage and air pollution;
- Safety & Reliability – Failures due to degradation can create public and worker hazards and result in forced outages with long restoration times; and
- Capacity – Degradation of the conductor can lead to de-rating of the circuit.

Summary of Solution:

To address the above issues and risks, the following staging of investments is recommended:

Short-Term:

- Continue to maintain and prioritize conductor replacements and upratings based on condition;
- Manage operation overload limits to avoid conductor damage;
- Continue with the copper conductor replacements planned for circuits 60L004, 60L011, and 60L054 on the south side of Burrard Inlet around Burnaby Mountain;
- Continue the conductor sampling program for ACSR conductor; and
- Address the end-of-life conductor issues at Jervis Inlet Crossing.

Medium and Long-Term:

- Continue the Copper Conductor Replacement Program; and
- Continue the ACSR conductor sampling program, and explore other inspection methods, to identify scope for future overhead conductor replacement capital program.

Name of Capital Strategy, Plan or Study:

Asset Management Strategy – Stations – Section 2.2.1 - Buildings

Summary of Issue:

BC Hydro has over 400 building in substations with buildings as old as 70 years in varying condition and of varying criticality. There are several types of building inside a substation. Types of buildings include:

- Control buildings;
- Gas insulated switchgear buildings;
- Indoor substation buildings;
- Storage buildings;
- Offices, workshops, and crew headquarters; and
- Standby diesel buildings, air compressor buildings, and others.

These assets provide all-weather protection and security for:

- Switchboard panels;
- Batteries and chargers;
- Protection & control and telecom equipment;
- Gas insulated switchgear equipment;
- Metal clad switchgear;
- Tools and spare parts, etc.; and
- Employee work areas.

The general issues and risks associated with buildings include:

- Reliability: Provide a secure environment that protects critical electronic, electrical or mechanical equipment from damage by rodents and the elements;
- Safety: Provide workers with a safe working environment and workspace for substation operation and maintenance work, including hazardous materials such as asbestos; and
- Regulatory: Maintain Mandatory Reliability Standards compliance, both by housing key assets and by providing physical security.

Summary of Solution:

The strategic replacement of control buildings approaching end of life is ongoing. The building needs are integrated with other substation upgrade projects such as protection and control modernization or replacement, and major substation expansion or renovation. New building designs include a plan to accommodate for future equipment expansions needs of the substation as well as meeting current engineering and regulatory standards.

The condition of assets is reviewed on a regular basis through recurring visual inspections, and, where required, detailed engineering assessments. The information on asset condition is used to assess the risk of failure of buildings and is used to prepare a consolidated list across the fleet to identify the timing to address the risks.

Short and Medium-Term:

- Port Alberni – Control Building replacement to address reliability and seismic risks;
- Prevost – Control Building replacement to address reliability and safety risks;
- Cathedral Square HVAC – Address reliability and safety risks of a failure of the HVAC system; and
- Williston – Control Building replacement to address reliability and safety risks.

Long-Term:

Approximately 22 per cent of buildings are over 40 years of age. Over the next 10 years, it is likely that a portion of these will degrade to poor or very poor condition. Remediation of the risks associated with these degrading assets will be required in the long-term.

Name of Capital Strategy, Plan or Study:

Asset Management Strategy – Section 2.2.2 – Circuit Breakers

Summary of Issue:

There are 3,968 circuit breakers operating at voltages from 2.4 kV to 500 kV in BC Hydro's substations. A circuit breaker fulfills two roles: first, it acts as an automatically operated switch to protect an electric circuit from damage caused by high currents; second, circuit breakers are used to disconnect or connect different components of the electric system. Circuit breakers contain high pressure air, oil, vacuum or sulphur hexafluoride (**SF6**).

The general issues and risks associated with the failure of circuit breakers include:

Reliability:

- Elevated reliability risk if the circuit breaker does not operate as intended causing damage to other equipment in the circuit; and
- Elevated reliability risk due to the sudden release of energy or fire impacting adjacent equipment.

Environment:

- Elevated risk of oil spills and polychlorinated biphenyl (**PCB**) contamination in the population of 470 oil filled circuit breakers; and
- Elevated environmental and safety risk associated with SF6 leakage from the population of 1,800 SF6 filled circuit breakers.

Reputation

- 134 circuit breakers contain PCB levels at or above 50 ppm which are required to be replaced by the December 31, 2025 Federal PCB Regulation deadline.

Safety:

- Elevated safety risk due to the sudden release of energy or fire; and
- Elevated safety risk when a circuit remains energized due to the improper opening of a circuit breaker.

Over the last 10 years, BC Hydro has installed over 1,712 new circuit breakers with two-thirds being installed in the distribution substations and the balance on the transmission system.

In the total population, 768 circuit breakers are currently over 40 years old, and approximately 638 (approximately 16 per cent) of the circuit breakers have an assessed Asset Health Rating of Poor or Very Poor, indicating that there is an increased likelihood of failure.

Summary of Solution:

BC Hydro has developed a long-term replacement strategy for circuit breakers to address the large number of aging circuit breakers and their associated risks. Historically the majority of work has been focused on replacing circuit breakers on the 500 kV, 360 kV and 230 kV system. More recently, the focus has shifted towards the lower voltage circuit breakers operating at 138 kV, 69 kV and lower.

To address the issues and risks identified above, a number of approaches are being taken, including:

- The replacement of circuit breakers will be included in the scope of work in discrete capital projects. These projects will often address multiple issues at a substation, of which the circuit breakers are one element;
- Circuit breaker replacement programs will focus on remediating the risks associated with the highest priority circuit breakers;
- A SF6 release mitigation strategy will continue to explore and implement non-SF6 circuit breaker alternatives where feasible;
- A spares strategy will continue to be implemented to ensure that adequate spare breakers and parts are available to minimize the impact of failures; and
- Consideration has been given to opportunities to decommission assets where replacement is not necessary.

Short-Term:

Asset condition is reviewed on a regular basis considering factors such as recurring test results, visual inspections, and detailed engineering assessments. This information is used to assess the risks related to each circuit breaker and to update a consolidated list with the intended timing of replacement investments.

Replacement projects that will occur in the short term are described in the table below.

Upon completion of the work outlined in the table below, all 134 remaining circuit breakers containing PCBs at or above 50 ppm will have been replaced or removed from service by the December 31, 2025 Federal deadline. The internal target is March 31, 2024.

	Circuit breaker will be addressed as part of a larger project	**Projects where the circuit breaker is the primary driver**
Replacement projects that are underway and will be completed in the short-term	N/A	• Atchelitz (8 x 25 kV) • Beaverley (3 x 69 kV) • Bridge River #1 (1 x 12kV) • Brocklehurst (10 x 25kV) • Carquille (3 x 69 kV) • Chevron Canada (4 x 69 kV) • Clayton Falls (2 x 25 kV) • Colwood (3 x 25 kV) • Dunsmuir (3 x 138 kV) • Esquimalt (6 x 12 kV) • Gibsons Landing (6 x 25 kV) • Houston (3 x 25 kV) • Illecillewaet (7 x 25 kV) • Kalum (3 x 25 kV) • Maple Ridge (1 x 25 kV) • New Westminster (5 x 12 kV) • Port Alberni (5 x 12 kV) • Port Alberni (6 x 25 kV) • Rainbow (4 x 25 kV) • Rupert (6 x 69 kV) • Saltspring (2 x 25 kV) • Salmon Arm (4 x 69 kV) • Salmon Valley (2 x 138 kV) • Sechelt (3 x 25 kV) • Shellburn (4 x 69 kV) • Sidney (5 x 25 kV) • Skeena (1 x 69 kV) • Squamish (6 x 25 kV) • Seton (3 x 69 kV) • Tachick (2 x 69 kV) • Westbank (1 x 69 kV) • Westbank (3 x 25 kV) • Williams Lake (5 x 25 kV)

	Circuit breaker will be addressed as part of a larger project	Projects where the circuit breaker is the primary driver
Replacement projects that will start and will be completed in the short -term	N/A	• Grief Point (1 x 12 kV) • Harewood (11 x 25 kV) • Hundred Mile House (2 x 69 kV) • Joseph Creek (2 x 69 kV) • Kootenay Canal (1 x 69 kV) • Lajoie (1 x 69 kV) • Minette (6 x 25 kV) • Salmon Arm (5 x 25 kV) • Soda Creek (1 x 69 kV)
Replacement projects that are underway and will continue into the medium term	• Barnard (18 x 12 kV) • Capilano (1 x 69 kV and 13 x 12 kV) • Kimberley (3 x 69 kV) • Kidd No. 1 (11 x 69 kV and 15 x 4 kV) • Mainwaring (18 x 12 kV) • Natal (2 x 138 kV and 8 x 69 kV) • Newell (20 x 12 kV) • Sperling (18 x 12 kV)	N/A
Replacement projects that will start in the short term, and continue into the medium term	• George Dickie (2 x 69 kV and 17 x 4 kV) • Glenmore (3 x 69 kV and 11 x 4 kV) • Horne Payne (14 x 12 kV) Norgate (4 x 69 kV and 15 x 12 kV) • Spillimacheen (2 x 69 kV and 1 x 12 kV)	• Vernon Terminal (2 x 69 kV)

Medium and Long-Term:

Considering the age and condition of the overall population of almost 4,000 assets, it is anticipated that a continued level of investment will be required. Replacement of the 12 kV, 25 kV, 69 kV and 138 kV circuit breakers will continue through the annual circuit breaker replacement programs. In addition, a number of discrete capital projects will address risks with the higher voltage circuit breakers, as part of their broader scope of work.

The goal is to manage the highest reliability, environmental and safety risks associated with circuit breakers. Approximately 20 per cent of the population is over 40 years old and will require remediation in the medium to long term as the assets move through their lifecycle. To pace these investments over time, approximately 100 units will need to be replaced on an annual basis, considering the design life of 35 to 40 years for circuit breakers. Factors such as age, condition and criticality will continue to be used for identifying the high priority units for replacement.

Name of Capital Strategy, Plan or Study: Asset Management Strategy – Lines – Section 2.1.5 – Underground and Submarine Cables
Summary of Issue: The major objective of the strategy is to achieve a life of 55 years for transmission cable systems, which is 15 years longer than the life stated by cable manufacturers, by targeted upgrades and refurbishments. BC Hydro has approximately 350 km of transmission cables, of which 196 km are submarine with the remainder being underground in mostly the Greater Victoria and Metro Vancouver areas. Cables are used to transfer electricity where it would be difficult or impractical to install overhead transmission lines, such as across large bodies of water or through cities where tall buildings or high density make it impossible. A cable system is comprised of a cable, duct banks, manholes, and ancillary equipment (such as pressurization and monitoring systems). There are two broad categories of cables: self-contained fluid-filled which uses paper and oil for insulation, and cross-linked polyethylene, which instead uses a form of plastic and is oil-free. The main issues and risks associated with transmission cables include: • Capacity - Historic growth can result in the need to operate existing cables closer to their maximum electrical rating which can result in higher temperatures and reduced life spans; • Security - Terminal structures where the cables connect to overhead lines are vulnerable to vandalism, particularly by copper thieves; • Reliability - Cables are essential for service for reliable transfer of electricity. Failed cables leading to forced outages may cause localized load shedding and impact system reliability significantly. Repairs take a long time and leave the system in a vulnerable state; and • Environmental - Fluid-filled cables can leak oil which can result in adverse environmental impacts. The risk of leaks increases with age as the cable’s outer metallic layer (which acts to contain the oil) fatigues. Recent projects have included installing temperature monitoring systems on the 230 kV cables in Vancouver to ensure the transmission cables are not overloaded and to gauge overall health. Installation of pressure monitoring systems to provide early warning of any leaks has also been completed. Additional spare cables have been purchased to reduce response times if cables are damaged.
Summary of Solution: To address the above issues and risks, the following staging of investments is recommended: **Short-Term:** • Continue with maintenance and inspection programs; • Replace the cable (2L146) between the Goward and Horsey substations; • Gulf Islands - Transmission Reinforcement Project; and • Refurbish pumping equipment to maintain and extend service life of fluid-filled cable systems. **Medium-Term:** • Expand use of temperature monitoring systems to measure cable temperature and adopt dynamic rating systems to allow for higher power transfers (by running closer to thermal limits) and defer cable replacements that may be required by growth needs. **Long-Term:** • Consider the replacement of the 138 kV submarine cable that supplies the Gulf Islands and Vancouver Island; and • Continue practice of installing solid-dielectric insulated cables to eventually phase out use of oil-filled transmission cables to mitigate potential environmental risk.

Name of Capital Strategy, Plan or Study:
Asset Management Strategy – Section 2.2.8: Oil Spill Containment

Summary of Issue:

Oil spill containment is an engineered asset, typically consisting of oil/water separators, tanks or pits, built in conjunction with oil containing equipment such as transformers, reactors or voltage regulators. In the event the oil is released accidently from equipment, oil spill containment is used to collect the oil and prevent contamination of the surrounding environment.

The general issues and risks associated with failure to contain an oil spill include:

- Environmental:
  - Contamination of land and water resources, and plant and animal species which can have long recovery times.
- Financial:
  - Costs associated with cleaning up areas affected by oil spills; and
  - Fines may be issued in the event of environmental damage.
- Reputational:
  - Spills that threaten the environmental quality of water, land or air must be reported to the regulatory agencies and may damage BC Hydro's reputation with government and the public.

BC Hydro has over 1,000 pieces of oil-filled substation equipment that individually contain more than 4,000 litres of oil.

Significant progress has been made to remediate these risks and over 400 oil-containing pieces of equipment have new or upgraded oil containment. However, approximately 600 oil-containing pieces of equipment still do not have adequate oil spill containment.

Summary of Solution:

A risk assessment has been completed at each of the substations containing oil-containing equipment. Factors considered in the risk assessment included the quantity of oil on site, and proximity to aquatic resources, wildlife, species at risk, habitats, parkland, and First Nations land. The risk assessment also considered the water use in the area and the likelihood of a spill.

To address the issues and risks identified above, two approaches are used:

- Capital projects which install large oil containing equipment will also have oil containment installed; and
- An oil containment projects, which prioritizes upgrades of legacy substations that do not meet the current standard, will address risks that are not otherwise addressed through a capital project.

Short-Term:

Activities that will be initiated in the short term are described in the table below.

	Oil spill containment that will be addressed as part of a larger project	**Projects where oil spill containment is the primary driver**
Containment activities that will be completed in the short term	N/A	• Atchelitz • Meridian
Containment activities that are underway, and will continue into the medium term	• Bridge River 1 • Bridge River Terminal • Capilano • Hundred Mile House • Jordan River • Natal • Newell	• Nelway • Soda Creek

	Oil spill containment that will be addressed as part of a larger project	Projects where oil spill containment is the primary driver
Containment activities that will start in the short term, and continue into the medium term	• Kelly Lake • Norgate • Patricia • Rosedale • Spillamacheen • Williston	• Valleyview • Ashton Creek

Medium-Term:

The investments outlined above address the most pressing risks associated with oil spill containment. The following substations are expected to have work initiated in the medium-term:

- Red Bluff;
- Rupert;
- Cathedral Square;
- Minette;
- Gold River;
- Cranbrook; and
- Harewood.

In the short- and medium-term this approach will reduce the risks associated with oil containment of another 10 per cent of equipment. This is an addition to the 40 per cent that already have adequate oil spill containment.

Long-Term:

In the long-term, work will continue to improve oil spill containment at a rate similar to the short- and medium-term and will be risk assessed and prioritized as outlined above.

Name of Capital Strategy, Plan or Study: Asset Management Strategy – Section 2.2.9: Series Capacitors

Summary of Issue:
BC Hydro has 15 series capacitors in nine separate substations, the majority of which are 500 kV units. They are expensive substation assets with long lead times to acquire and replace. The majority of series capacitors were original installations built from 1980s to 2010s. Series capacitors are used to increase the transmission system transfer capability, improve voltage stability, and optimize power flow between parallel circuits.
The general issues and risks associated with the failure of series capacitors include:
• Reliability:
  - Reduced transfer capability and increased network risks associated with the transmission system; and
• Safety & Financial:
  - The increased likelihood of a failure or fire poses a safety risk to workers and may cause damage to surrounding assets.
Over the last 20 years, BC Hydro has refurbished 4 series capacitors at three substations (MLS, CHP, CRK). BC Hydro has also developed and implemented a spares strategy and has purchased strategic spare parts to minimize impacts of a failure.
Approximately 8 series capacitors are between 10 and 40 years old. Of the 15 series capacitors, two have been assessed as being in Poor Asset Health Rating, indicating that they have an increased likelihood of failure.

Summary of Solution: To address the issues and risks identified above, two general approaches are identified: • Capital projects have been identified to remediate the risks associated with series capacitors with the highest risk of failure. New or refurbished units will be installed; and • A spares strategy will continue to ensure that critical spares are available to minimize the impact of series capacitor failures. **Short and Medium-Term:** Condition of assets is reviewed on a regular basis considering such factors as recurring test results, visual inspections, and, where required, detailed engineering assessments. This information is used to assess the likelihood of failure of each series capacitor. This risk-based approach is used to identify the appropriate timing to replace capacitors and components thereof. The series capacitors with a highest priority for refurbishment or replacement are: • KDY 5CX1, 5CX2, 5CX3; • MLS 5CX3; and • AMC 5CX1, 5CX2. **Long-Term:** The series capacitor fleet may contain a number of units with an Asset Health Rating of poor and very poor after the completion of the short-term and medium-term investments. The risks associated with the health of these assets will need to be addressed in the long term, following similar assessment and prioritization techniques to those outlined above.

Page 1 of 1

Name of Capital Strategy, Plan or Study:

Asset Management Strategy – Section 2.2.10: Shunt Reactors

Summary of Issue:

BC Hydro has 142 shunt reactors in its substations, the majority of which are 500 kV units. Shunt reactors are oil filled and similar in construction to transformers. They are expensive substation assets with long lead times to acquire and replace. The majority of shunt reactors were installed from the 1960s to 1980s when most of the 500 kV transmission lines were built. Shunt reactors have two main purposes: firstly, they are used to help control the voltage on the transmission system under certain operating conditions and, secondly, they are used to protect the transmission cables from potential damage due to over voltages.

The general issues and risks associated with the failure of shunt reactors include:

- Reliability:
  - Reduced transfer capability and increased network risks associated with the transmission system; and
  - Elevated transmission system voltages which can damage the transmission cables.
- Environmental:
  - Elevated risk of oil spills, particularly in locations with less robust spill containment and more sensitive environments.
- Safety & Financial:
  - The increased likelihood of a fire poses a safety risk to workers and may cause damage to surrounding assets.

Over the last 20 years, BC Hydro has replaced nine shunt reactors at eight substations. BC Hydro has also developed and implemented a spares strategy and has purchased four reactors for 230 kV and 500 kV spares to minimize impacts of a failure. The total value of the investment in spares was over $5 million.

Approximately 67 shunt reactors are between 40 and 50 years old and seven are more than 50 years old. Of the 142 shunt reactors, 58 (40 per cent) have been assessed as being in Poor or Very Poor Asset Health Rating, indicating that they have an increased likelihood of failure.

Summary of Solution:

To address the issues and risks identified above, two general approaches are identified:

- Capital projects have been identified to remediate the risks associated with shunt reactors with the highest risk of failure. New units will be installed with oil spill containment; and
- A spares strategy will continue to ensure that critical spares are available to minimize the impact of shunt reactor failures.

Short & Medium-Term:

Condition of assets is reviewed on a regular basis considering such factors as recurring test results, visual inspections, and, where required, detailed engineering assessments. This information is used to assess the likelihood of failure of each reactor and to prepare a consolidated list across the system. The risk-based list is used to identify the appropriate timing to replace individual reactors. The reactors with the highest priority for replacement are:

- G.M. Shrum substation 500 kV line reactors (six in total);
- Williston substation (sixteen reactors); and
- Kelly Lake substation (six reactors).

Long-Term:

The reactor fleet will contain a number of units with an Asset Health Rating of poor and very poor after the completion of the short-term and medium-term investments. The risks associated with the failing health of these assets will need to be addressed in the long term, following similar assessment and prioritization techniques to those outlined above.

Name of Capital Strategy, Plan or Study:

Asset Management Strategy – Section 2.2.15: Synchronous Condensers

Summary of Issue:

There are eight synchronous condensers on the BC Hydro system all of which are over 40-years old. Four are located at Burrard Synchronous Condenser Station, three are at Vancouver Island Terminal and one is at Kelly Lake substation. They are expensive assets with long lead times to acquire and replace. Synchronous condensers are rotating machines that are similar to generators. Each machine has a number of supporting systems, including a gas handling system, an excitation system, and a protection and control system. These assets are used to provide system voltage control and contribute to the system stability.

This strategy focuses on the four synchronous condensers at Vancouver Island Terminal and Kelly Lake substation as the future use of synchronous condensers at Burrard Synchronous Condenser Station is presently under review.

The main issues and risks with the synchronous condensers are:

- Safety - There are fire risks associated with leaks in the hydrogen gas handling systems; and
- Reliability - The excitation and the protection and control systems are aging, with increased likelihood of failure. There are obsolescence issues and spare parts can be challenging to source given that manufacturer support is limited. These issues can result in long downtimes if a unit is forced out of service.

Over the last 10 years, BC Hydro completed refurbishment of the windings and internal components of each of the four machines. BC Hydro also developed and implemented a spares strategy and made additional investments in spare parts to minimize outage time in the event of failures. To help with troubleshooting, BC Hydro increased the use of on-board diagnostics and implemented a knowledge transfer process to enhance its repair capability in the field. The total value of these investments was over $26 million.

As a result of this work, the overall condition of the assets at Vancouver Island Terminal and Kelly Lake substation has improved. However, reliability and safety risks remain with specific supporting systems, such as gas handling, excitation and protection and control.

Summary of Solution:

To address these issues and risks, the following approaches will be taken:

- Capital projects will upgrade the gas handling, excitation, and the protection and control subsystems of each unit;
- A spares strategy will ensure that critical parts are available to facilitate breakdown repairs and shorter outages; and
- Increased use of on-board diagnostics to shorten outages.

Short-Term:

Investments will begin in the short-term with projects for each of the four synchronous condensers to focus on addressing the remaining risks in the support systems, namely the gas handling system, excitation system, and the protection and control system.

Medium and Long-Term:

Given that the assets at Vancouver Island Terminal and Kelly Lake substation are over 40-years old, a level of ongoing work will be required as the assets progress through their lifecycle and risks associated with falling health of these assets will need to be addressed. The unit located at Kelly Lake substation is expected to be replaced with a new reactor by 2025.

Name of Capital Strategy, Plan or Study:

Asset Management Strategy – Section 2.2.16: Power Transformers

Summary of Issue:

There are 672 power transformers with a voltage class of 60 kV or greater at BC Hydro substations. Transformers are one of the most critical and expensive assets in a substation and have long lead times to acquire and replace. Transformers fulfill multiple roles in the power system. Firstly, power transformers are used to increase the voltage to a level that can be transmitted over long distances via the transmission network. Secondly, in the transmission network, transformers are used to connect systems that are operated at different voltages. Finally, transformers are used to reduce transmission voltages to a lower level that can be distributed to customers.

The general issues and risks associated with a failure of a power transformer include:

- Reliability:
  - Elevated risk of customer outages at single transformer distribution substations, and a loss of redundancy at multi transformer distribution substations; and
  - Reduced transfer capability and increased network risks associated with the transmission system.
- Environment:
  - Elevated risk of oil spills, particularly in older transformers with less robust oil spill containment.
- Safety & Financial:
  - The increased likelihood of a fire poses a safety risk to workers and may cause damage to surrounding assets.

Over the last 10 years, BC Hydro has installed 62 transformers at 44 substations. BC Hydro has also developed and implemented a spares strategy and has purchased 10 new spare transformers of different ratings to minimize impacts in the event of a failure. The total value of these investments was over $330 million.

Approximately 147 transformers are between 50 and 60-years old and 71 are more than 60-years old. Approximately 69 (10 per cent) of the total power transformers have been assessed as having Poor or Very Poor Asset Health Rating, indicating that there is an increased likelihood of failure.

Summary of Solution:

The following approaches have been taken to address the issues and risks identified above:

- The identification of capital projects to remediate the risks associated with some of the transformers;
- The development of a spares strategy that will continue to be implemented, as necessary, to ensure that critical spares are available to minimize the impacts of a transformer failure; and
- The decommissioning of assets where replacement is no longer necessary.

Transformer assets may be addressed as part of larger integrated projects within a station or region of the system or as part of standalone project.

Short-Term:

The condition of assets are reviewed on a regular basis considering such factors as recurring test results, visual inspections, and, where required, detailed engineering assessments. This information is used to assess the likelihood of failure of each transformer to help prepare a consolidated list across the fleet to identify the timing to address the risks.

Activities that will occur in the short term are described in the table below. Note that many of the investments initiated in the short term will continue to have capital expenditures and will go into service in the medium term.

	Transformers that will be addressed as part of a larger project	Projects where the transformer is the primary driver
Activities that will be completed in the short-term	N/A	N/A
Activities that are underway, and will continue into the medium-term	• Capilano (60/12 kV) • Kidd 1 (60/4 kV) • Mainwaring (230/12 kV) • Mount Lehman (230/25 kV) • Natal (138/60 kV) • Newell (230/12 kV) • Skookumchuk (60/12 kV) • Woss (138/12 kV) • Canal Flats (60/12 kV) • Diana Lake (60/12 kV)	• Bridge River 1 (60/238 kV) • Bridge River Terminal (345/230 kV) • Hundred Mile House (60/238 kV) • Jordan River (13/25/138 kV) • Rosedale (345/230 kV)
Activities that will start in the short-term, and continue into the medium-term	• Norgate (60/12 kV) • Patricia (60/12 kV) • Balfour (60/12 kV); • Coquitlam (60/12 kV); • Glenmore (60/4 kV); • Loughheed (60/12 kV); • Quesnel (60/12 kV); • Richmond (60/12 kV); • Scott Road (60/12 kV); • Sumas Way (60/25 kV); • Surrey (60/12 kV)	N/A

Medium-Term:

The investments outlined above address the most pressing risks associated with the transformers. Additional transformers may need to be addressed by future projects in the medium-term. The strategy and prioritization of risk reductions will be continually monitored over time as other transformers degrade and the risk assessments are updated.

Long-Term:

There are approximately 147 transformers between 40 to 50-years of age. Over the next 10 years, it is likely that a portion of these will degrade to Poor or Very Poor Asset Health Rating. Remediation of the risks associated with these degrading assets will be required in the long-term, applying similar assessment and prioritization techniques to those outlined above.

Name of Capital Strategy, Plan or Study: Asset Management Strategy – Telecom Transport
Summary of Issue: BC Hydro's Telecommunications system enables the safe, reliable and efficient operation of the Bulk Electric System by providing highly-available telecom services in support of Teleprotection, Supervisory Control and Data Acquisition, Remedial Action Scheme, operational voice, mobile radio and corporate network functions. The system is made up of many elements, including fiber optics, microwave radios, powerline carrier equipment, satellite terminals, multiplexors, routers and switches. Ancillary equipment such as buildings, towers, antennas, batteries, chargers and backup power generators are also included. The general issues and risks associated with the failure of telecommunication equipment include: • Reliability: - Visibility and control of remote substations would be lost by the control centres; - High-speed line protection would be lost, reducing the transfer capacity of the affected lines by 40 to 60 per cent to ensure stability; and - Remedial Action Scheme schemes would be lost, leading to interconnecting entities reducing or cutting off the interconnection until the services are restored. • Safety: - The loss of operational voice and mobile radio services reduces the ability of the control centre to coordinate safety-critical work with field crews; and - Field crews are dispatched to effect a timely repair of the failed equipment. Much of this equipment is located on the tops of mountains. It can be unsafe to access these sites during winter storm conditions. The two most significant issues with Telecom Transport equipment are asset age, and the large number of single points of failure at mountaintop microwave repeaters. Both of these issues pose a risk to the reliability of the Telecommunications system. The focus of the Telecom Transport strategy is on the maintenance of the assets. The Telecom Resiliency Strategy focuses on addressing the risks of single points of failure. Much of the existing system was originally installed in the late 1990s and early 2000s and has reached end of life. Vendors no longer offer technical support or replacement parts. Currently, the Vancouver Island Microwave replacement project is replacing end of life telecom equipment in the Vancouver Island area. In addition to the above risks, the demand for telecommunications services, especially at remote stations, is growing quickly. It is difficult to meet this demand over a constrained microwave radio link, especially when no commercial services are available to supplement the BC Hydro network. Moreover, fewer telecom equipment vendors are offering for sale equipment that fully supports Time Division Multiplexing circuits, but many legacy protection and control devices require this functionality. Equipment replacement must consider both the legacy needs of the connected devices, as well as the future needs of new packet-based communications.
Summary of Solution: The overall strategy is to address the two most significant risks of equipment age and the presence of single-points of failure. Asset condition is reviewed on a regular basis, and the timing of the planned projects are adjusted relative to asset condition and system risk. **Short-Term:** • Complete the Vancouver Island Microwave radio replacement project; • Initiate a provincial telecom equipment replacement project to replace the oldest radios and network equipment. This project will also extend the use of packet technology to enable the efficient use of constrained network links, and to enable a transition to future packet-based communications system; and

Page 1 of 2

- Continue sustainment of mobile radio systems and ancillary equipment such as towers, batteries and chargers, and diesel generators.

Medium-Term:

- Initiate equipment replacement projects for radios and network equipment installed in the late 2000s to 2010s. Continue network migration to packet-based transport systems;
- Initiate powerline carrier replacement project;
- Initiate private cellular network project to replace end-of-life WiMAX and TETRA radio systems; and
- Continue sustainment of mobile radio systems and ancillary equipment such as towers, batteries and chargers, and diesel generators.

Long-Term:

- Initiate equipment replacement projects for radios and network equipment installed in the 2020s. Complete network migration to packet-based transport systems; and
- Continue sustainment of mobile radio systems ancillary equipment such as towers, batteries and chargers, and diesel generators.

Name of Capital Strategy, Plan or Study: Barnard Asset Plan
Summary of Issue: The 191 MVA Barnard substation is a transmission and distribution substation serving North Burnaby and portions of West Coquitlam and Port Moody. First commissioned in 1954, the substation consists of: • Three switchyards: 230 kV, 69 kV, and 12 kV; • Two power transformers; and • Three feeder sections. Barnard is an important substation given its dual role as both a transmission station and a distribution station. The station serves over 40,995 customers and has the seventh largest peak load (133 MVA) in the Lower Mainland Metro region. Barnard provides one of the two transmission supplies to Lougheed substation and to six transmission voltage customer substations including Simon Fraser University. Since being commissioned in 1954, BC Hydro has expanded the substation over time and made investments in the past 20 years totaling over $30 million. Recent investments have included the addition of a new feeder section in 2008 and the replacement of all the circuit breakers in the 69 kV switchyard in 2020. There is an ongoing project to replace the 50/ 60 series feeder sections. The most significant remaining issues and risks associated with Barnard substation include: • One of the older feeder sections was designed to be compact in size and poses safety risks for workers due to limited clearance between energized equipment and ground. The risk is currently partially mitigated through physical barriers and warning signs. This risk will be addressed by the ongoing 50/ 60 series feeder section replacement project; • There are elevated reliability risks associated with the above-mentioned older feeder section due to the poor condition of 67 per cent of the 18 circuit breakers and 96 per cent of the 56 disconnect switches. The oil-filled circuit breakers in this feeder section also contain polychlorinated biphenyl (**PCB**) levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline. This risk will be is addressed by the ongoing 50/ 60 series feeder section replacement project; and • There are elevated reliability risks associated with the 230 kV switchyard, due to obsolescence issues with the original mechanical protection and control relays.
Summary of Solution: The Barnard Asset Plan presents a strategy to replace assets on a component-by-component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. The safety issues associated with the feeder sections of compact size will be addressed concurrently with equipment replacement projects. In the short and medium term, the focus will be on higher priority investments required for safe and reliable transmission and distribution of energy and to meet the requirements to phase out PCBs by the end of 2025. The longer-term activities are anticipated to focus on the remaining feeder sections and the transformers. **Short and Medium-Term:** • Address the safety and reliability risks associated with the older feeder section that has high risk by replacing it with a new indoor feeder section; • Address the reliability risks associated with protection and control equipment for the other older feeder section and the 230 kV switchyard by replacing the associated protection and control panels; and • Remove equipment with PCB levels at or above 50 ppm by the December 31, 2025 Federal Regulation deadline.
Long-Term: • The equipment at the Barnard substation will continue to degrade over time, and a level of investment is anticipated in the longer term to preserve the reliability of the substation and address emerging risks. Expected investments are required to address the risks associated with the transformers.

Name of Capital Strategy, Plan or Study:
BC Hydro Transmission System Seismic Vulnerability Analysis
Summary of Issue: BC Hydro has significant exposure to major earthquakes that present a risk to the reliability of the transmission system including at our substations, overhead structures, and underground and submarine cables. In 2014 BC Hydro commissioned a study of the seismic vulnerability of the transmission system to better understand this risk. BC Hydro engaged specialist consultants to evaluate the key transmission assets in and around the Metro Vancouver and Victoria load centers including the substations, major overhead, underground and submarine lines, and their resiliency to transfer power to the B.C. load centres. The analysis reported that BC Hydro has been diligent in managing and mitigating the exposure to seismic risk over the past 30 years, with our performance matching or exceeding that of many other high voltage transmission system operators along the west coast of the United States. Over the past 30 years, BC Hydro has actively reduced seismic vulnerabilities to the transmission system, by a combination of construction of new submarine and buried cables; equipment replacement in high voltage yards; selective upgrades of seismically-weak control buildings; seismic upgrade of many 230 kV potheads; and selective upgrade of towers at major river crossings. Most of these upgrade efforts have been concentrated in the Lower Mainland and Vancouver Island, where the seismic hazard is highest. The analysis also identified some key vulnerabilities to BC Hydro including our buried and submarine high voltage cables, power transformer bushings, cable slack, potheads, tsunami inundation, and transmission towers subject to liquefaction or landslides. A prioritized list of system upgrades was identified to further reinforce the transmission system.
Summary of Solution: To continue addressing the known issues and risks, the following staging of investments is recommended: **Short-Term:** • Address very high priority seismic vulnerabilities including upgrading of bushings and potheads and seismic reinforcement of key infrastructure; and • Maintain robust spare strategy and response planning. **Medium and Long-Term:** • Execute the recommended capital investments in order of priority over the long-term; • Reinforce critical overhead crossings vulnerable to liquefaction including 2L003/2L49; • Monitor and reinforce critical lines vulnerable to seismic generated landslide activity including 5L42, 5L29, 5L30, 5L31, 5L32; • Seismic upgrades and reinforcement of substation yards and apparatus including ground improvement in liquefaction zones; and • Upgrades and replacements of vulnerable buried and submarine cables.

Name of Capital Strategy, Plan or Study: Bridge River Transmission System Upgrade – Network Integrated Transmission Service Study
Summary of Issue: Generation from the Bridge River System[1] and several nearby Independent Power Producers (**IPP**) is transmitted through three regional paths towards the Lower Mainland load center. By 2022, approximately 400 MW of IPP generation is expected to be connected to the Bridge River Transmission System. While BC Hydro's Bridge River 1 and 2 Generating Stations have been de-rated over the past decade, BC Hydro is now investing in these units to restore their capacity. Units 5 and 6 at the Bridge River 2 Generating Station were replaced in fiscal 2019 and fiscal 2020, respectively. Generating Units 7 and 8 at the Bridge River 2 Generating Station are being replaced in fiscal 2021 and fiscal 2022. The Bridge River 1 Project will replace Units 1 to 4 at the Bridge River 1 Generating Station. Collectively, these projects will restore the overall capacity of the Bridge River Facility to 532 MW. In 2017, BC Hydro conducted a transmission study to assess the impact of increased IPP generation and the restoration of generation capacity at the Bridge River Facility to the Bridge River Transmission System. The system study shows that by 2030, during the summer months, when generation output is high and local load is low, the amount of electric current flowing through the 2L90 circuit will reach up to 838 A (338 MVA), or over 160 per cent of its thermal rating of 510 A (203 MVA).
Summary of Solution: The strategy is to provide adequate transmission capacity to eliminate system constraints and avoid the need for generation curtailment during summer months. In all alternatives the refurbishment of 2L90 is included, as a significant number of wood structures on that circuit are in poor condition and require replacement, and there are other associated defects that require repair. **Short and Medium-Term:** Alternatives that are being considered to deliver on this strategy include: • Uprating the 230 kV transmission line (2L90) between Bridge River Terminal and Kelly Lake substation; • Upgrading Rosedale transformer and sustaining circuit 2L90; and • Curtailing local generation and sustaining circuit 2L90.

1 The Bridge River System consists of the La Joie Generating Station, Bridge River 1 and Bridge River 2 Generating Stations, and Seton Generating Station.

Name of Capital Strategy, Plan or Study:
Burrard Synchronous Condenser Replacement Study
Summary of Issue: The Burrard Synchronous Condenser Station (**BSY**) is the former Burrard Generation Station, and in past years four of the original six generating units were converted to run as synchronous condensers, each providing nominally -50/+100 MVar of reactive power to the Lower Mainland regional transmission system, and also providing support for the Interior-to-Lower Mainland power transfer. This Capital Plan addresses two issues: • Issue 1: End-of-Life BSY Asset Condition - The Burrard synchronous condensers are nearing end of life and the reactive power capacity that the units provide to the transmission system needs to be retained or replaced. • Issue 2: Fraser Valley Regional Reactive Power Support - Based on recent Transmission Planning performance assessments, the Fraser Valley regional transmission system is expected to experience voltage regulation and voltage stability constraints within next five to 10 years due to load growth. In order to meet the performance criteria required under the current Mandatory Reliability Standards, additional reactive power support is required in the Fraser Valley regional system.
Summary of Solution: The strategy is to retain or replace the capacitive and reactive power functions of Burrard synchronous condensers in the short- and medium-term using the minimum capital investment that can meet the timeline of the synchronous condenser end of life issues and Fraser Valley regional transmission system's voltage constraint problem. The two needs are addressed in one project to optimize the reactive power planning in Lower Mainland and further save the system investment and operation cost by reducing total reactive power requirement and deferring the system investment in Fraser Valley regional transmission system. The long-term strategy is to develop a plan to meet long term domestic load supply and firm transmission service requirement for the Fraser Valley regional transmission system and the Interior-to-Lower Mainland bulk transmission system. **Short and Medium-Term:** A capital plan project was initiated to retain or replace the Burrard capacitive and reactive power functions, with a projected in-service date of October 2025. The Leading Alternative comprises of installing equipment at the following substations: • Ingledow: 2 x 230 kV, 125 MVAr capacitor banks, • Meridian: 2 x 230 kV, 132 MVAr shunt reactors, • Fleetwood: 2 x 230 kV, 125 MVAr capacitor banks, • Meridian: 1 x 230 kV, 125 MVAr capacitor banks, and • Clayburn: 1 x 230 kV, 125 MVAr capacitor banks. **Long-Term:** BC Hydro will develop a long-term strategy for the Fraser Valley regional transmission system and the Interior-to-Lower Mainland bulk transmission systems once a long-term load forecast, generation resource plan and BC Hydro's 2021 Integrated Resource Plan are completed.

Page 1 of 1

Name of Capital Strategy, Plan or Study:

Downtown Vancouver Electric Supply Plan

Summary of Issue:

The Downtown Vancouver study area is comprised of the Downtown, West End, Strathcona, and Grandview-Woodland neighborhoods. The area is supplied by a 230 kV and 69 kV transmission network and three substations:

- Cathedral Square substation which has a capacity of 302 MVA was built in 1984;
- Dal Grauer substation which has a capacity of 195 MVA was built in 1953; and
- Murrin substation which has a capacity of 200 MVA was built in 1947.

The study area contains the largest commercial centre in Vancouver and has the highest load density in B.C. The area has approximately 100,000 customers and had a peak load of 409 MVA in fiscal 2020. The present area firm capacity is 697 MVA.

BC Hydro has made investments in this area in the past 20 years totaling over $300 million. Recent investments include the addition of a transformer and a feeder section at Cathedral Square substation in 2009 and the construction of a new 230 kV transmission cable circuit from Mount Pleasant substation to Cathedral Square substation in 2014.

The most significant issues and risks remaining in the Downtown Vancouver area include:

- There are elevated reliability risks at Dal Grauer and Murrin substations where more than half of the substation assets are expected to be in an assessed Asset Health Rating of Poor or Very Poor condition within the next 10 to 20 years;
- Seven of the 11 transmission cable circuits supplying the three stations are expected to be in an assessed Asset Health Rating of Poor or Very Poor condition within 20 years;
- More than half of the distribution cables at Dal Grauer and Murrin substations are expected to be in Poor or Very Poor condition within 20 years;
- The 12 kV equipment at Dal Grauer and Murrin substations exposes workers to safety risks due to limited clearance between energized equipment and ground. This risk is currently partially mitigated through physical barriers and warning signs;
- The indoor circuit breakers and exposed bus at Dal Grauer and Murrin substations expose workers to safety risks from potential arc flashes in the event of insulation failures; and
- Murrin substation is on seismically unstable soil. Approximately half of the 230 kV switchyard, which supplies both Murrin and Dal Grauer substation loads, is vulnerable to severe earthquake damage from liquefaction and settlement. All loads being served from Dal Grauer and Murrin substations may experience a prolonged outage after a seismic event.

Summary of Solution:

The long-term strategy for the area is to mitigate the above reliability and safety risks by replacing Murrin and Dal Grauer substations with new substations. The addition of the new substations will be timed to precede the need to retire major existing equipment as the assets approach their end of life. This means that new capabilities will need to be created, while older assets are still in service, in anticipation of the declining condition of a large population of assets. The sequencing of activities will need to be carefully planned and staged over the long-term, to minimize or avoid stranded investments in assets that may not be required in the long-term.

The Downtown Vancouver Electricity Supply Plan examined four alternatives, each of which considered:

- The need to reduce seismic risk exposure;
- The health of each substation’s assets, and their expected degradation over time;
- The present area capacity and future load growth;
- Opportunities to transfer load to neighboring substations outside the study area;
- Opportunities to permanently decommission substations;

- The feasible timing of required work and the need to maintain sufficient area capacity;
- The costs of the different solutions;
- Performance and reliability requirements in the downtown area;
- Local stakeholder support; and
- Environmental impacts.

In light of the sizeable and complex issues noted above, the criticality of load in the downtown area, and the lead time required to build new substations in the Downtown Vancouver Area, it was particularly important to consider a long-term planning horizon.

For the Downtown Vancouver Area the following strategy is being implemented:

Short and Medium-Term:

- West End Substation:
  - Build a new underground 230/25 kV substation in the West End neighbourhood. This substation will have an ultimate capacity of 400 MVA; and
  - Build new 230 kV cable circuits to connect the new substation to the existing system.
- East Vancouver Substation:
  - Build a new indoor 230/25 kV, substation in the Strathcona neighbourhood. This substation will also have an ultimate capacity of 400 MVA.

Both new substations above represent important infrastructure in critical locations that are anticipated to be in place for more than 50 years. The ultimate 800 MVA capacity of the two substations will not be installed immediately, but provides flexibility for growth over time, as the need for the load materializes.

Long-Term:

The activities outlined above have a relatively long lead time, and will enable a number of activities in the long-term:

- Offload the Dal Grauer substation to the West End substation;
- Offload the Murrin substation to the East Vancouver substation;
- Decommission the Dal Grauer and Murrin substations, as well as the 69 kV circuits;
- Replace the 230 kV cables that are in poor condition as required; and
- Add new 230 kV transmission circuits as required to meet future load growth.

Name of Capital Strategy, Plan or Study: Fraser Valley Reinforcement Study
Summary of Issue: The Telecom Transport asset strategy identifies single points of failure at mountaintop telecom repeaters as a key system resiliency risk. The Fraser Valley Reinforcement study identifies Sumas Mountain (**SMS**) microwave repeater as a telecom site with a particularly significant impact in the event of a failure. A failure of the telecom system at the SMS microwave repeater would result in the loss of operational communications to: • One 500 kV substation in the U.S. (Custer); • One BC Hydro 500 kV substation (Clayburn); • Two 360 kV substations (Rosedale; Upper Harrison Terminal); • Three 230 kV substations (Atchelitz; McLellan; Mount Lehman); and • Three generating stations (Wahleach; Ruskin; Stave Falls New). Of these, only McLellan substation has an alternative communications path via fiber to another site on the communication network. The SMS microwave repeater is also a component of the microwave ring connecting the Lower Mainland and the South Interior. The loss of this site would reduce the communications capacity and reliability of the network supporting teleprotection, remedial action scheme and supervisory control and data acquisition services for the bulk electric system. In December 2019, a failure of telecom equipment at the SMS microwave repeater led to a four-hour outage to teleprotection and remedial action scheme circuits. Fortunately, impacts to the power system were avoided due to the rapid restoration of the failed equipment. Additional single points of failure related to mountaintop repeaters at other locations in the province will be addressed by projects resulting from the Telecom Resiliency Strategy.
Summary of Solution: The study identifies alternatives to provide diverse network paths to maintain communications in the event of a telecom system failure at the SMS microwave repeater. These alternatives include the building of new microwave repeaters and links, the building of fiber optic cables between the affected stations, the obtaining of dark fiber leases from carriers, or some combination of the above. **Short-Term:** • Reinforce the telecom system in the Fraser Valley to mitigate the risks of a failure at SMS microwave repeater. **Medium-Term:** • Complete the Fraser Valley Reinforcement project. **Long-Term:** Certain electronic components of the telecom system in the Fraser Valley have been identified as being end of life and will be replaced under another investment.

Page 1 of 1

Name of Capital Strategy, Plan or Study:

Integrated Planning Report for Capilano and Lynn Valley Substations and Distribution Area / Norgate Asset Plan

Summary of Issue:

North Vancouver is comprised of two municipalities, the City of North Vancouver and the District of North Vancouver. The area is bounded by the Capilano River to the west, the North Shore mountains to the north, Burrard Inlet to the south and Indian Arm to the east. There are approximately 64,000 customers in this area. The total load in 2020 was 206 MVA.

The City and District of North Vancouver and surrounding areas are supplied by five main substations, which together have a winter capacity of 331 MVA:

- North Vancouver has a capacity of 67 MVA and was built in 1950s;
- Lynn Valley has a capacity of 100 MVA and was built in the 1980s;
- Norgate has a capacity of 53 MVA and was built in the 1960s;
- Capilano has a capacity of 56 MVA and was built in the 1950s; and
- John Lawson has a capacity of 55 MVA and was built in the 1950s.

Over the past 10 years BC Hydro has undertaken investments to maintain and upgrade three of these substations, including the addition of a new feeder section at Lynn Valley in 2013, a complete 12 kV rebuild of the North Vancouver substation in 2012, and cable upgrades, additional feeder positions and circuit breaker replacements at John Lawson substation between 2009 and 2016. At Capilano and Norgate substations, most of the assets are at end of life and there are safety and other issues which need resolution.

The Capilano substation serves over 12,000 customers, and consists of:

- A 60-12 kV switchyard;
- Two power transformers; and
- One feeder section.

The most significant issues and risk at the Capilano substation include:

- A significant portion of the equipment has a poor Asset Health Rating, including both of the 60 kV circuit breakers, 85 per cent of the 27 protection and control assets, 88 per cent of the 56 disconnect switches, and 50 per cent of the 42 the instrument transformers; and
- The existing feeder section building does not meet current seismic standards. The feeder section has limited clearance between energized equipment and ground. The risk is currently partially mitigated through physical barriers and warning signs. The building also sustained a major water leak in 2019.

The Norgate substation serves over 4500 customers and consists of:

- A 60 -12 kV switchyard;
- Three power transformers; and
- One feeder section.

The most significant remaining issues and risks at Norgate substation include:

- All three power transformers are in poor condition and subject to oil leaks;
- Seven circuit breakers and three voltage transformers contain Polychlorinated Biphenyl (**PCB**) at levels at or above 50 ppm which will be replaced by the December 31, 2025 Federal PCB Regulation deadline;
- The majority of the remaining substation assets have a Poor Asset Health Rating including: 42 per cent of the 17 circuit breakers, 64 per cent of the 11 reactors, 94 per cent of the 31 protection and control assets, and 87 per cent of the 52 disconnect switches; and
- The feeder section has worker safety issues related to limited clearance between energized equipment and ground. The risk is currently partially mitigated through physical barriers and warning signs which create access restrictions during maintenance and operations.

Summary of Solution:

Performing work at these substations is complex. Space is often limited, meaning that workers have to work in close proximity to the energized equipment when the major construction needs to be done to replace/add the equipment. To continue to supply the load to the customers during construction, the new equipment and infrastructure has to be added before it is possible to take existing equipment out of service since there is a limited capacity to transfer the load to neighboring stations. Creating space within the substations would sometimes be challenging or require expansion of the substation footprint.

The strategy for the area is intended to sequence work in such a way that the issues and risks outlined above are mitigated, while continuing to provide reliable supply to customers. The development of a strategy for the area will consider a number of factors, including:

- The current capacity and projected growth of the area;
- The condition of the assets at different area substations, and their expected degradation over time;
- The sequencing and timing of required sustainment work at area substations combined with the need to manage overall area capacity;
- Minimize/avoid stranded investment in the area substations by optimizing the planning and the staging of work; and
- Opportunities to utilize capacity at neighboring substations.

Short and Medium-Term:

- A project is underway to rebuild Capilano substation with a capacity of 100 MVA.
  - A new substation will be built within the footprint of the existing substation fence;
  - The load from the existing 56 MVA substation will be transferred to the new substation; and
  - The existing 56 MVA substation will be decommissioned.
- A project will start in the short-term to decommission Norgate substation.
  - Cascading transfer of load from Norgate substation to North Vancouver substation and from North Vancouver to Lynn Valley substation; and
  - Decommission all equipment from Norgate substation.

When all the above investments are completed there will be significant improvements in the overall equipment condition and reliability of the area supply. The safety and seismic risks will be mitigated, and PCBs will have been removed ahead of the end of 2025 Federal PCB Regulation deadline. The area will have the necessary capacity to accommodate the future growth in the area.

Long-Term:

In the longer term, it is anticipated that a component-by-component replacement strategy will be undertaken at the different substations to address risks with discrete assets as they degrade over time.

Name of Capital Strategy, Plan or Study: Kidd 1 Asset Plan
Summary of Issue: Kidd 1 substation is a transmission and 100 MVA distribution substation that serves Vancouver South. First commissioned in 1951, the substation consists of: • One 69 kV switchyard which has nine transmission line terminal positions and four transformer positions; • Four power transformers; • One 4 kV feeder sections and two 12 kV feeder section; • One control building; and • One 230 kV cable terminal. Kidd 1 is an important substation given its dual role as both a transmission substation and a distribution substation. The station serves over 20,000 customers and has the fifteenth largest peak load (69 MVA) in the Lower Mainland Metro region. Kidd 1 substation provides the primary transmission source for George Dickie and Big Bend substations. Kidd 1 substation also supplies six transmission voltage customers and the distribution is adjoined by Sperling substation providing some flexibility to transfer load between the two substations. Since commissioning in 1951, BC Hydro has expanded the Kidd 1 substation over time and made investments in the past 20 years totaling over $35 million. Recent investments have included the replacement of two transformers and addition of a feeder section in 2014. The most significant remaining issues and risks associated with Kidd 1 substation include: • One power transformer has an assessed Asset Health Rating of Very Poor and has significant leaks; • There are elevated reliability risks associated with the 69 kV switchyard, due to an assessed Asset Health Rating of Poor of 92 per cent of the 12 circuit breakers and 95 per cent of the 37 disconnect switches. The oil-filled circuit breakers also contain polychlorinated biphenyl (**PCB**) levels at or above 50 ppm which need to be replaced by the December 31, 2025 Federal PCB Regulation deadline. The 69 kV bus structure was not designed or built to the latest seismic standards. A study indicates that the structure is likely to collapse in an earthquake would occur, on average, 1 in 475 years; • There are elevated reliability and safety risks associated with the control building due to leaking, cracking, severe deterioration, overcrowding, asbestos and seismic deficiency of the control building. Approximately 40 per cent of the Protection & Control relays and panels in the control building have an assessed Asset Health Rating of Poor and approximately 70 per cent are mechanical type from the original installation and are obsolete; and • The 4 kV feeder section at Kidd 1 is obsolete and no longer provides any benefit for the system. All of the 4 kV load has been converted to 12 kV. The equipment associated with the 4 kV feeder section has an assessed Asset Health Rating of Poor and has reached end of life.
Summary of Solution: The Kidd 1 Substation Asset Plan presents a strategy to replace assets on a component-by-component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. The safety issues associated with the compact sections of the substation will be addressed concurrently with the equipment replacement projects or by the decommissioning of the equipment. In the short- and medium-term, the focus will be on higher priority investments required for safe and reliable transmission and distribution of energy and to meet the requirements to phase out PCBs by the end of 2025.

Short and Medium-Term:

- Decommission the 4 kV feeder section, two 4 kV power transformers and control building;
- Replace the 60 kV circuit breakers and protection and control system; and
- Remove equipment with PCB levels at or above 50 ppm by the December 31, 2025 Federal PCB Regulation deadline.

Long-Term:

The equipment at the Kidd 1 substation will continue to degrade over time, and a level of investment is anticipated in the longer term to preserve the reliability of the substation and address emerging risks. Expected investments are required to address those risks associated with the remaining outdoor feeder section and the 69 kV switchyard that are not resolved in the short or medium term.

Name of Capital Strategy, Plan or Study:

Mainwaring Asset Plan

Summary of Issue:

The 211 MVA Mainwaring substation is a transmission and distribution substation serving Vancouver South. First commissioned in 1957, the substation consists of:

- Two switchyards: 230 kV and 12 kV;
- Three power transformers; and
- Two feeder sections.

Mainwaring is an important substation given its dual role as both a transmission station and a distribution station. The substation serves over 65,000 customers and has the fourth largest peak load (177 MVA) in the Lower Mainland Metro region. Mainwaring substation provides one of the two transmission supplies to Camosun substation. There is also flexibility to transfer the distribution load between the adjoining Newell and Mount Pleasant substations.

Since commissioning in 1957, BC Hydro has expanded the Mainwaring substation over time and made investments in the past 20 years totaling $25 million. Recent investments have included the replacement of a transformer in 2006 and replacement of the 230 kV circuit breakers in 2007 and 2011.

The most significant remaining issues and risks associated with Mainwaring substation include:

- One of the power transformers has an assessed Asset Health Rating of Poor and is gassing. One other transformer has significant oil leaks. It does not have on-load tap changer; therefore, voltage regulators in the feeder sections are required to regulate the voltage;
- Both feeder sections were designed to be compact in size and pose safety risks for workers due to limited clearance between energized equipment and ground. The risk is currently partially mitigated through physical barriers and warning signs;
- There are elevated reliability risks associated with the 12 kV switchyard, due to Asset Health Rating of Poor of 35 per cent of the 51 circuit breakers, 87 per cent of the 38 voltage regulators, 56 per cent of the 41 current limiting reactors and 80 per cent of the 153 disconnects; and
- One circuit breaker in the 12 kV switchyard and the bushings on two of the transformers also contain polychlorinated biphenyl (**PCB**) levels at or above 50 ppm which will need to be replaced by the December 31, 2025 Federal PCB Regulation deadline.

Summary of Solution:

The Mainwaring Substation Asset Plan presents a strategy to replace assets on a component-by-component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. The safety issues associated with the compact sections of the substation will be addressed concurrently with equipment replacement projects. In the short and medium term, the focus will be on higher priority investments required for safe and reliable transmission and distribution of energy and to meet the requirements to phase out PCBs by the end of 2025. The longer-term activities are anticipated to focus on the remaining equipment and the control building.

Short and Medium-Term:

- Address reliability risk associated with two of the power transformers;
- Address the safety and reliability risks associated with the two feeder sections; and
- remove equipment with PCB levels at or above 50 ppm by the December 31, 2025 Federal PCB Regulation deadline.

Long-Term:

The equipment at the Mainwaring substation will continue to degrade over time and investment is anticipated in the longer term to preserve the reliability of the substation and address emerging risks, including those associated with the control building.

Name of Capital Strategy, Plan or Study:
Natal Asset Plan

Summary of Issue:

Natal substation is a transmission substation located in the Southern Interior region, near Sparwood, that consists of:

- Two switchyards: 230 kV and 60-138 kV; and
- Four power transformers and one voltage regulator

The 60-138 kV switchyard was commissioned in 1968 and the 230 kV switchyard was commissioned in 1972. Natal substation is an important transmission substation given its role both as a bulk transmission substation and a source of supply for industrial customers. The station serves 10 industrial customers. Natal substation is also a point of intertie with the Alberta transmission system.

BC Hydro has made investments in the past 20 years totaling over $5 million. Recent investments have included replacement of 60 kV surge arrestors, 138 kV circuit breakers and 230 kV circuit breakers.

The most significant remaining issues and risks associated with Natal substation include:

- There are elevated reliability risks due to the Asset Health Rating of Poor of two of the four power transformers, one voltage regulator, 35 per cent of the 14 circuit breakers, 49 per cent of the 44 instrument transformers, as well as a significant proportion of the protection and control systems supporting the 60-138 kV switchyard;
- Three of the 60 kV circuit breakers contain polychlorinated biphenyl (**PCB**) levels at or above 50 ppm which need to be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline; and
- The 60 kV structure is wood pole and timber type, while the 138 kV structure is mixed wood and steel; they were designed and built to electrical clearance at the time and pose safety risks for workers due to limited clearance between energized equipment and ground. This risk is currently partially mitigated through physical barriers and warning signs.

Summary of Solution:

The Natal Substation Asset Plan presents a strategy to replace the 60-138 kV switchyard. The safety issues associated with the substation will be addressed concurrently with the equipment replacement projects or by the decommissioning of the equipment. In the short term, the focus will be on higher priority investments required for safe and reliable transmission of energy and to meet the requirements to phase out PCBs by the end of 2025. The medium to long-term activities are anticipated to focus on sustain activities of the remaining equipment.

Short Medium-Term:

- Address the reliability, environment and safety risks of the 60 kV and 138 kV equipment. The scope of this work will include the replacement of the power transformers, voltage regulator, circuit breakers, instrument transformers, bus structure, protection and control systems and control building in the switchyard.

Long-Term:

- The equipment at the Natal substation will continue to degrade over time, and investment is anticipated in the longer term to preserve the reliability of the substation and address emerging risks. Investments will be required to address the risks associated with the 230 kV switchyard as it approaches poor asset health.

Name of Capital Strategy, Plan or Study:
Newell Asset Plan

Summary of Issue:

The Newell substation is a transmission and 234 MVA distribution substation that serves South Burnaby. First commissioned in 1955, the substation consists of:

- One 230-60 kV switchyard;
- Five power transformers;
- Four 12 kV feeder sections; and
- One control building.

Newell is an important substation given its dual role as both a transmission station and a distribution station. The station serves over 50,000 customers and has the third largest peak load (186 MVA) in the Lower Mainland Metro region. There is flexibility to transfer the distribution load between the adjoining Big Bend and Mainwaring substations.

Since commissioning in 1955, BC Hydro has expanded the substation over time and made investments in the past 20 years totaling over $25 million. Recent investments have included addition of a new feeder section in 2003 and replacement of the 230 kV circuit breakers in 2011.

The most significant remaining issues and risks associated with Newell substation include:

- One power transformer (**T1**) has an Asset Health Rating of Poor, has significant oil leaks and contains polychlorinated biphenyl levels at 25 ppm; and
- One of the feeder sections was built in the 1950s (50/60 Series). The feeder section is compact in size and poses safety risks for workers due to limited clearance between energized equipment and ground. This risk is currently partially mitigated through physical barriers and warning signs. Of the feeder section, 16 of 18 circuit breakers, 17 of 18 voltage regulators, 16 of 18 current limiting reactors and 46 of 54 disconnect switches have an Asset Health Rating of Poor or Very Poor.

Summary of Solution:

The Newell Substation Asset Plan presents a strategy to replace assets on a component-by-component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. The safety issues associated with the compact sections of the substation will be addressed concurrently with equipment replacement projects. In the short-term, the focus will be on higher priority investments required for safe and reliable transmission and distribution of energy and to meet the requirements to phase out polychlorinated biphenyls by the end of 2025. The medium to longer-term activities are anticipated to focus on the remaining feeder sections, substation security and the control building.

Short and Medium-Term

- Address reliability and safety risks associated with the power transformer and feeder section. The recommended alternative is to remove the power transformer T1 and replace feeder section 50/60 Series.

Long-Term:

- The equipment at the Newell substation will continue to degrade over time and investment is anticipated in the longer term to preserve the reliability of the substation and address emerging risks. Expected investments are required to address the risks associated with the two remaining feeder sections, enhance the security of the substation, and address risks associated with the degrading control building.

Name of Capital Strategy, Plan or Study: North Burnaby Area Study
Summary of Issue: The North Burnaby study area is comprised of a 230 kV and 69 kV transmission network and the following three substations: • Horne Payne substation which has a capacity of 340 MVA was built in 1910; • Lougheed substation which has a capacity of 55 MVA was built in 1957; and • Barnard substation which has a capacity of 188 MVA was built in 1950. The area has approximately 95,000 customers and had a peak load of 343 MVA in fiscal 2020. The present area firm capacity is 583 MVA. Recent investments include the construction of a new 230 kV to 25 kV switchyard at Horne Payne substation in 2019 and the refurbishment of the 69 kV switchyard at Barnard substation in 2019. The most significant issues and risks remaining in the North Burnaby area include: • There are elevated reliability risks at Horne Payne, Lougheed, and Barnard substations where 15 per cent of the substation assets have an Asset Health Rating of Poor or Very Poor and an additional 57 per cent are expected to be in an Asset Health Rating of Poor or Very Poor within the next 10 to 20 years; and • Some of the 12 kV equipment at the Horne Payne, Lougheed and Barnard substations exposes workers to safety risk due to limited clearance between energized equipment and ground. The risk is currently partially mitigated through physical barriers and warning sings.
Summary of Solution: The North Burnaby Area Study presents a strategy to mitigate the reliability and safety risks in the short-term by adding a new 25 kV switchyard at Horne Payne (completed in 2019) and using this supply to offload and decommission higher risk feeder sections. In the long term, assets would be replaced on a component-by-component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. The study examined two alternatives in detail, each of which considered: • The health of each substation’s assets, and their expected degradation over time; • The present area capacity and future load growth; • Opportunities to transfer load to neighboring substations outside the study area; • Opportunities to permanently decommission substations; • The feasible timing of required work and the need to maintain sufficient area capacity; • The costs of the different solutions; • Performance and reliability requirements of the area; • Local stakeholder support; and • Environmental impacts. **Short-Term:** • Address the safety and reliability risks associated with the feeder section at Barnard substation that has high risk by replacing it with a new indoor feeder section; • Address the safety and reliability risks associated with Lougheed substation by voltage converting and transferring the load to Horne Payne substation and decommissioning Lougheed substation; • Address the safety and reliability risks associated with the feeder section at Horne Payne substation that has higher risk by voltage converting and transferring the load to the newly constructed 25 kV switchyard at Horne Payne substation and decommissioning the feeder section; and

- Remove equipment with polychlorinated biphenyl (**PCB**) levels at or above 50 ppm by the December 31, 2025 Federal PCB Regulation deadline.

Medium-Term:

- Add a new half feeder section in the Horne Payne 25 kV switchyard to facilitate further voltage conversions and offloading of higher risk feeder sections at Horne Payne substation.

Long-Term:

- In the longer term, it is anticipated that a component-by-component replacement strategy will be undertaken at the different substations to address risks with discrete assets as they degrade over time.

Name of Capital Strategy, Plan or Study:

Oldfield Asset Plan

Summary of Issue:

Oldfield substation is a 66 MVA distribution station located in the northeast corner of Yellowhead Highway 16 and 11th Ave East in Prince Rupert. First commissioned in 1967, the substation consists of:

- One 60 kV switchyard;
- Four power transformers;
- One 12 kV feeder section and one 25 kV feeder section; and
- One control building.

The station is the main source of electricity for 7357 customers in the Prince Rupert area.

Since commissioning in 1967 with 12 kV capacity, BC Hydro added 25 kV capacity to the substation in 1982. The 25 kV transformer capacity is sufficient to supply all the current load at 12 kV and 25 kV, so the 12 kV load could be converted to 25 kV.

The most significant remaining issues and risks associated with Oldfield substation include:

- There are elevated reliability risks associated with the 12 kV feeder section due to the Asset Health Rating of Poor of all the eight circuit breakers, all of the 6 voltage regulators, two 69-12 kV power transformers, lack of a transfer bus in the 25 kV feeder section and obsolete protection and control relays; and
- Five circuit breakers and three voltage regulators in the feeder section contain polychlorinated biphenyl (**PCB**) levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline.

Summary of Solution:

The Oldfield Substation Asset Plan presents a strategy to replace assets on a component-by-component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. The safety issues associated with the compact sections of the substation will be addressed concurrently with equipment replacement projects. In the short term, the focus will be on higher priority investments required for safe and reliable transmission and distribution of energy and to meet the requirements to phase out PCBs by the end of 2025. The medium to longer term activities are anticipated to focus on the remaining power transformers, substation security and the control building.

Short-Term:

- Two new 25 kV feeders will be constructed. The 12 kV load will be converted and transferred to the new 25 kV feeders;
- The 12 kV feeder section and the associated protection & control relays will be decommissioned;
- Two 69-12 kV power transformers, the associated disconnect switches and protection & control relays will be decommissioned; and
- The equipment containing PCBs at levels at or above 50 ppm will be removed by the December 31, 2025 Federal PCB Regulation deadline.

Medium-Term:

- Three 25 kV vacuum circuit breakers, trench covers, and switchyard gravel are planned to be replaced by fiscal 2027 when they are expected to reach end of life.

Long-Term:

- The equipment at the Oldfield substation will continue to degrade over time, and investment is anticipated in the longer term to preserve the reliability of the substation and address emerging risks. Investments will be required to address the risks associated with the two remaining power transformers, to enhance the security of the substation and address risks associated with the degrading control building.

Name of Capital Strategy, Plan or Study: Patricia Asset Plan
Summary of Issue: The 87 MVA Patricia substation is a distribution substation that serves Prince George. First commissioned in 1964, the substation consists of: • Two switchyards: 60 kV and 12 kV; • Three power transformers; and • One feeder section. Patricia substation is the only distribution station supplying load to the downtown area of Prince George. The station serves over 14,000 customers making it the second largest substation by customer count in the Northern Interior region. The Patricia substation load cannot be served from the surrounding substations due to different distribution voltages (12 kV vs 25 kV). Since being commissioned in 1964, BC Hydro has expanded the Patricia substation over time and made limited investments in the past 20 years totaling over $2 million. Investments have included replacements of circuit breakers and surge arresters in the 12 kV and 60 kV switchyards. The most significant remaining issues and risks associated with Patricia substation include: • The three power transformers were manufactured in the 1960s and do not have on-load tap changers, therefore voltage regulators are required to regulate the voltage. One of the power transformers has an Asset Health Rating of Poor; • All 12 kV voltage regulators have an Asset Health Rating of Poor; • The 12 kV feeder section was designed to be compact in size and poses safety risks for workers due to limited clearance between energized equipment and ground. This risk is currently partially mitigated through physical barriers and warning signs; and • Thirteen 12 kV bulk oil circuit breakers have an Asset Health Rating of Poor and contain PCB levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline.
Summary of Solution: The Patricia Substation Asset Plan presents a strategy to address asset risks on a component-by-component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. The safety issues associated with the compact section of the substation will be addressed concurrently with equipment replacement projects. In the short-term, the focus will be on higher priority investments required for safe and reliable distribution of energy and to meet the requirements to phase out PCBs by the end of 2025. The medium to longer-term activities are anticipated to focus on the remaining feeder section issues and the control building. **Short and Medium-Term:** • Address the environment risks of the 12 kV bulk oil circuit breakers containing PCBs; and • Address the reliability and safety risks of the equipment. The leading alternative is to replace the existing transformers with new transformers that have on-load tap changers, enabling the removal of the voltage regulators in the feeder section and mitigate the electrical clearance issues. **Long-Term:** • The equipment at the Patricia substation will continue to degrade over time, and investment is anticipated in the longer-term to preserve the reliability of the substation and address emerging risks. Investments will be required to address the risks associated with the two substation service transformers, and also address risks associated with the degrading control building.

Name of Capital Strategy, Plan or Study:
Sperling Asset Plan

Summary of Issue:

The 214 MVA Sperling substation is a transmission and distribution substation that serves Vancouver West. First commissioned in the 1940s, the substation consists of:

- Three switchyards: 230 kV, 69 kV and 12 kV;
- Two power transformers; and
- Four feeder sections.

Sperling is an important substation given its dual role as both a transmission station and a distribution station. The station serves approximately 60,000 customers and has the fifth largest peak load (171 MVA) in the Lower Mainland Metro region. There is also flexibility to transfer the distribution load between the adjoining Camosun, Mount Pleasant and Kidd 1 substations. The Sperling 69 kV switchyard is in the process of being decommissioned to alleviate the elevated reliability risk due to the poor condition of the disconnect switches and control panels, etc.

Since commissioning in the 1940s, BC Hydro has expanded the Sperling substation over time and made investments in the past 20 years totaling over $30 million. Recent investments have included the addition of a new indoor feeder section in 2009 and the replacement of the circuit breakers in an older indoor feeder section in 2012.

The most significant remaining issues and risks associated with Sperling substation include:

- The two outdoor feeder sections were designed to be compact in size and pose safety risks for workers due to limited clearance between energized equipment and ground. This risk is currently partially mitigated through physical barriers and warning signs;
- There are elevated reliability risks associated with one of the outdoor feeder sections and transformer circuit breakers due to the Poor Asset Health Rating of 90 per cent of the 10 circuit breakers, and 93 per cent of the 56 disconnect switches. The oil-filled circuit breakers in these feeder sections also contain Polychlorinated Biphenyl (**PCB**) levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline; and
- All eight indoor transformer circuit breakers pose safety risks for workers due to the potential for arc flash hazards in the event of failures.

Summary of Solution:

The Sperling Substation Asset Plan presents a strategy to replace assets on a component-by-component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. The safety issues associated with the two feeder sections of compact size will be addressed concurrently with other equipment replacement projects. In the short and medium-term, the focus will be on higher priority investments required for safe and reliable transmission and distribution of energy and to meet the requirements to phase out PCBs by the end of 2025.

Short and Medium-Term:

- Address the safety and reliability risks associated with one of the outdoor feeder sections and the bus breakers by replacing them with a new indoor feeder section in a new building;
- Remove equipment with PCB levels at or above 50 ppm by the December 31, 2025 Federal PCB Regulation deadline; and
- Complete addressing the reliability risk associated with the 69 kV switchyard by decommissioning the switchyard and control building at Sperling. The transfer of the UBC load to the adjoining Camosun substation was completed in 2020.

Long-Term:

The equipment at the Sperling substation will continue to degrade over time, and investment is anticipated in the longer term to preserve the reliability of the substation and address emerging risks. Expected investments are required to address the risks associated with the remaining outdoor feeder section and transformers that were installed in the 1970s.

Name of Capital Strategy, Plan or Study:

Telecom Resiliency Strategy

Summary of Issue:

The Telecom Transport asset strategy identifies single points of failure at mountaintop telecom repeaters as a key system resiliency risk. The Telecom Resiliency Strategy further defines risks and sets forth the strategy to address these risks.

The telecom network is built in parallel to the 500 kV bulk electric system using mostly microwave radio links. This system provides Teleprotection, Remedial Action Scheme and Supervisory Control and Data Acquisition services in support of the bulk system. The telecom network must meet Western Electricity Coordinating Council availability and redundancy requirements for BC Hydro to safely and reliably operate of the power system and to remain interconnected with neighbouring entities.This results in a maximum permissible outage duration of four hours to key telecom circuits before actions must be taken on the power system to reduce transmission line or interconnection capacity.

On long radial circuits, BC Hydro uses frequency diversity radios and equipment redundancy to meet the Western Electricity Coordinating Council redundancy requirements. However, single points of failure still exist in this arrangement, and there are many failure modes:

- Line of sight obstructions (icing, smoke, atmospheric conditions);
- Power interruptions (fuses, diesel generator problems, distribution power outages); and
- Infrastructure problems (antenna and waveguide breaks, tower or building issues).

It is difficult or impossible to resolve the above failures within the four-hour limit. In addition, even for simple failures, mountaintop sites can be difficult to access in a safe and timely manner to effect repairs, especially during winter storm conditions. As a result, mountaintop sites are presently engineered for very high reliability, with many redundant systems, requiring high capital and maintenance costs. Even with the high level of investment, the single points of failure are not eliminated.

The issues identified in this strategy were also studied specificially in the Fraser Valley Telecom Reinfocement study as pertaining to risks at the Sumas Mountain Microwave Repeater.

Summary of Solution:

Two independent networks, operating in parallel and having no common single points of failure, provide a higher level of availability than a single network with multiple single points of failure. Having two networks with a maximum four-day restoration time would provide equivalent performance of a single network with a four-hour restoration time. This study recommends building such a parallel network for key portions of the system.

Adding a second network in parallel would also enable the reduction of investment in capital and maintenance costs to the existing network, as the existing network would then have lower effective performance requirements. In addition, capital replacements of telecommunications network equipment would be simplified, as the old equipment would not need to be maintained in service while the cutovers are effected. This would reduce the cost and complexity of equipment replacement projects.

This study identified key areas of the telecom network that would most benefit from having a second network added in parallel, including the Peace to Kelly Lake, Prince George to Terrace, and Kelly Lake to Vernon networks. Alternatives to provide parallel paths could consist of building new microwave repeaters, building new fiber optic cables, or obtaining dark fiber leases from carriers.

Short-Term:

- Initiate a resiliency project that would build a parallel network for key segments of the system in advance of the planned major telecom equipment replacement project. This investment would enable cost and complexity savings for the equipment replacement project.
  - Confirm the priority of the network areas to receive parallel links;
  - Select a leading alternative; and

- Build the leading alternative. Coordinate the construction schedule so it is completed in advance of the equipment replacement project in order to maximize the benefits to the other project.
- Initiate a resiliency project for Sumas Mountain.

Medium-Term:

- Complete the resiliency project;
- Study the performance of the sections of the system having parallel, diverse networks;
- Optimize the capital and maintenance plans to reflect the lower level of performance required due to the presence of parallel network links; and
- Plan future network resiliency projects.

Long-Term:

- Execute further network resiliency projects;
- Optimize the capital and maintenance plans to reflect the lower level of performance required due to the presence of parallel networks; and
- Plan future network resiliency projects.

Name of Capital Strategy, Plan or Study:
Transmission Load Interconnection Studies for North Montney Region Electrification
Summary of Issue: The North Montney natural gas field has numerous gas producers for well drillings and gas extractions northeast of BC Hydro's G.M. Shrum Generating Station. Presently, BC Hydro does not have transmission facilities in this region and is not able to provide electricity supply to the natural gas producers. Recently, natural gas producers have expressed their strong interest in powering their facilities from BC Hydro's grid to reduce greenhouse gas emissions. Because this region is far from BC Hydro's existing electric grid, a major transmission system extension to North Montney region is required to accommodate transmission voltage customer load interconnections, which would be uneconomical for any single natural gas producer to undertake. BC Hydro initiated a North Montney Region Electrification project. The government funding support and First Nations' involvements would make the transmission extension project economically viable to interconnect multiple natural gas producers. This transmission extension would contribute to the Government of B.C.'s CleanBC goal of increasing access to clean electricity for large operations.
Summary of Solution: BC Hydro plans to construct a new 230 kV transmission circuit from the main grid to a new 230/138 kV substation in the vicinity of Wonowon community, which could potentially be the North Montney load centre, with an expected in-service date in 2027. **Short and Medium-Term:** BC Hydro launched an expression of interest process to learn the interest of gas producers to electrify their facilities. More technical and economic analysis will be performed to optimize the solution. The transmission extension project is currently in Conceptual Design Stage, and investigations are underway to assess the two alternatives: • Construct a 230 kV transmission line between G.M. Shrum Generating Station and the new 230/138 kV substation; and • Construct a 230 kV transmission line between South Bank substation and the new 230/138 kV substation.

Page 1 of 1

Name of Capital Strategy, Plan or Study: West Kelowna Area Study
Summary of Issue: The 138/25kV Westbank (**WBK**) Substation supplies the West Kelowna area and is connected only to Nicola Substation by a single 80 km long radial 138 kV transmission line. Westbank Substation has no ties to any other substations and there is no local generation to serve the load in the area. Consequently, if the radial transmission line is out of service, the 22,000 customers in the West Kelowna area will experience an outage. In the past, the geographic area of the transmission line has been subjected to wildfires. In addition, there is a need to increase the station capacity at Westbank Substation. The substation has three 138 kV/25 kV transformers with a summer firm capacity of 80 MVA (assumes the loss of a transformer). Firm capacity was exceeded by 15 per cent in fiscal 2019 by the summer load demand. Also, some equipment that has been in-service since the early 1970s, is nearing end-of-life and needs replacement.
Summary of Solution BC Hydro is evaluating alternatives to address the above issues with an integrated approach. **Short- and Medium-Term:** • The West Kelowna Transmission Project (**WKTP**) will mitigate the natural hazard risks to the West Kelowna transmission system by providing redundancy to the system; and • Westbank Substation Upgrade Project will increase firm transformation capacity, replace end-of-life assets at WBK and interconnect the new transmission line.

Name of Capital Strategy, Plan or Study:

Wood Pole Substation Strategy

Summary of Issue:

There are 48 substations that have been classified as Wood Pole substations for asset management and planning purposes. Collectively, all of these substations serve approximately 75,000 customers. Their common characteristics generally include:

- Individually, these are small distribution stations, the majority of which have a load of less than 15 MVA and serve less than 3,000 customers;
- Usually located in remote rural locations, often at the end of a radial line;
- A wooden structure is used to mount electrical equipment such as disconnect switches;
- A single power transformer;
- A small number of feeder positions (usually less than four);
- No control room; and
- Mobile transformers are required in the event of a failure.

The general issues and risks associated with Wood Pole substations include:

- Reliability:
  - The poor condition of the wooden structures represents an elevated reliability risk. The wooden cross members in the structure can fail, physically contacting nearby equipment, and causing customer outages; and
  - The Poor Asset Health Rating of equipment such as transformers, disconnect switches and voltage regulators represents an elevated reliability risk. Limited redundancy in these substations means that a failure of any one component has a high likelihood of causing a total outage of the station.
- Safety:
  - The degrading condition of the wooden structure represents a safety hazard to workers inside the substation; and
  - The compact size poses safety risks for workers due to limited clearance between energized equipment and ground. This risk is currently partially mitigated through physical barriers and warning signs.
- Environmental:
  - Much of the oil filled equipment in wood pole substations contains Polychlorinated Biphenyl (**PCB**) levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline.

Over the last 20 years, BC Hydro has invested approximately $60 million in addressing the most pressing risks at 12 of the 48 Wood Pole substations. Work at another three Wood Pole substations is also currently underway. BC Hydro has also invested in mobile transformers to act as emergency replacements in the event of failures at the Wood Pole substations.

Approximately 68 per cent of the 48 Wood Pole substations are over 50-years old, with 50 per cent over 60-years old. Approximately 45 per cent of equipment within the Wood Pole substations has been assessed as having an Asset Health Rating of Poor or Very Poor, indicating that there is an increased likelihood of failure.

Summary of Solution:

Wood Pole substation investments are prioritized considering factors such as the age and condition of the wood poles, the condition of equipment within the substation, as well as the criticality of the substation. To address the above issues and risks, the following staging of investments is recommended:

- Firstly, capital projects have been identified to remediate the risks associated with the Wood Pole substations. The scope of these projects will be tailored to suit the specific Wood Pole substation, and the risks, ranging from the replacement of targeted assets to a redevelopment of the substation;

- Secondly, a contingency strategy, utilizing mobile transformers, will continue to be implemented, as necessary, to ensure mobile transformers are available to minimize the impacts of equipment failure; and
- Finally, consideration has been given to find opportunities to decommission stations where replacement can be avoided by finding other economical solutions.

Short and Medium-Term:

The condition of assets is reviewed on a regular basis considering such factors as recurring test results, visual inspections, and, where required, detailed engineering assessments. This information is used to assess the risk of failure at each Wood Pole substation to help prepare a consolidated list across the fleet and identify the potential timing to address the risks. Below is a list of those substations with a higher priority:

- Clinton - Substation Wood Pole Replacement;
- Chase - Substation Wood Pole Replacement;
- Joseph Creek Substation Upgrade;
- Sandspit Substation Replacement;
- Lumby #2 - Substation Wood Pole Replacement;
- Diana Lake - Substation Wood Pole Replacement;
- Canal Flats - Substation Wood Pole Replacement;
- Skookumchuck - Substation Wood Pole Replacement;
- Woss - Substation Wood Pole Replacement; and
- Telegraph Creek - Substation Replacement.

Long-Term:

The investments outlined above will address the highest priority risks. However, considering that some Wood Pole substations were constructed in the 1970s and 1980s, additional work is anticipated in the long term. The strategy and prioritization will continually be monitored over time.

Name of Capital Strategy, Plan or Study:

Asset Management Strategy - Section 3.1.8: Street Lighting

Summary of Issue:

BC Hydro owns and maintains approximately 90,000 street lights mounted on BC Hydro or Joint Use (co-owned with TELUS) poles, and 4,970 leased private outdoor lighting units installed on customer or BC Hydro owned poles located on private property. Most BC Hydro street lights are high pressure sodium technology while most private outdoor lights are mercury vapour technology.

BC Hydro provides street lighting and private outdoor lighting service to various customers to:

- Support night-time safety for the general public and for private properties; and
- Contribute to reliability by reducing outages due to vehicular accidents through improved visibility.

The main issues and risks associated with street lighting and private outdoor lights include:

- Approximately 20 per cent of BC Hydro's lights may contain Polychlorinated Biphenyls (**PCB**), which must be removed from the system by December 31, 2025 in accordance with Federal PCB Regulations;
- Municipalities are increasingly interested in implementing various cost and energy-saving initiatives such as Light Emitting Diode (**LED**) technology lights;
- The private outdoor light rate schedule was closed in 1975 and assets including lights and poles are at or near end of life. Investing in replacing these assets without upfront cost paid by customers puts BC Hydro at financial risk of not recovering these costs from these closed rate schedule lights; and
- High pressure sodium and mercury vapour lamps fail every five to seven years on average resulting in outages that need repairs in a timely manner. Meeting the street lighting outage response target of 10 working days is challenging in certain smaller districts of the province due to lack of dedicated resources.

Summary of Solution:

BC Hydro is currently implementing a LED Street Light Conversion project that will replace all 90,000 street lights to LED and remove approximately 4,600 private outdoor lights off of the system. The remaining 370 private outdoor lights will be converted to LED and transitioned to the street light rate schedule. The project began installing LED street lights starting in December 2020.

LED street lights offer an approximate 20-year life span with no lamps or other consumables to be replaced during this period.

A Street Light Rate Application was submitted to the BCUC in November 2020 to amend the existing street light rates to include LEDs and rescind private outdoor light service.

Short-Term:

With 54,000 units planned to be addressed in fiscal 2021 and fiscal 2022, fiscal 2023 through fiscal 2025 will see approximately 36,000 street lights and 370 private outdoor lights converted to LED and 4,600 private outdoor lights removed. Beyond fiscal 2025, the program will transition to sustainment to address units that fail in-service.

Medium and Long-Term:

Sustainment will continue for approximately 20 years after installation.

BC Hydro
Power smart

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix L

Asset Health - Generation

Table of Contents

1 Introduction

BC Hydro assesses the asset health of its Generation, Transmission and Distribution assets to inform the life-cycle management of the assets, including supporting the need for capital investments. BC Hydro uses two different asset health methodologies each of which provide a systematic, objective, repeatable, and transparent assessment of asset health.

BC Hydro uses a methodology called Equipment Health Rating to evaluate the health of Generation assets. For reporting purposes, results are presented using a common Asset Health Rating for Generation, Transmission and Distribution assets on a scale of Good, Fair, Poor and Very Poor.

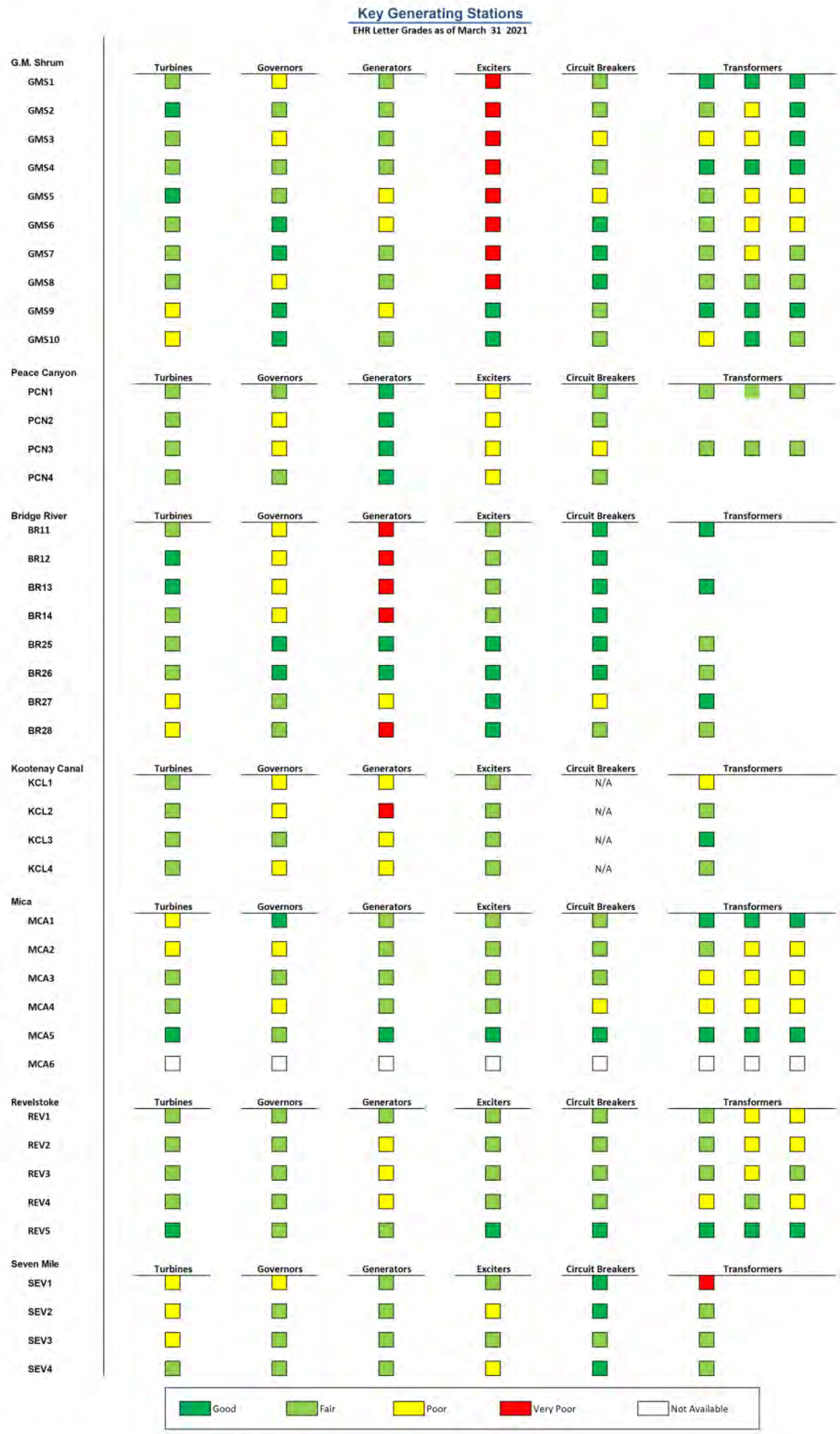
2 Generation Equipment Health Ratings

BC Hydro periodically evaluates the condition of its major generation assets (turbines, generators, governors, exciters, transformers, and circuit breakers) based on the latest available maintenance test and inspection data. Health assessments are based primarily on asset condition, but also consider safety and environmental issues, reliability, design deficiencies, asset age and industry expected life and availability of spare parts and technical expertise.

Each health assessment results in a rating of Good, Fair, Poor, or Very Poor:

	Description
Good	As new condition, with no noticeable deterioration or defects
Fair	Normal deterioration of the asset with one or more minor defects; function is not affected
Poor	Serious deterioration of the asset or serious defects
Very Poor	Extensive serious deterioration of the asset or asset function is affected

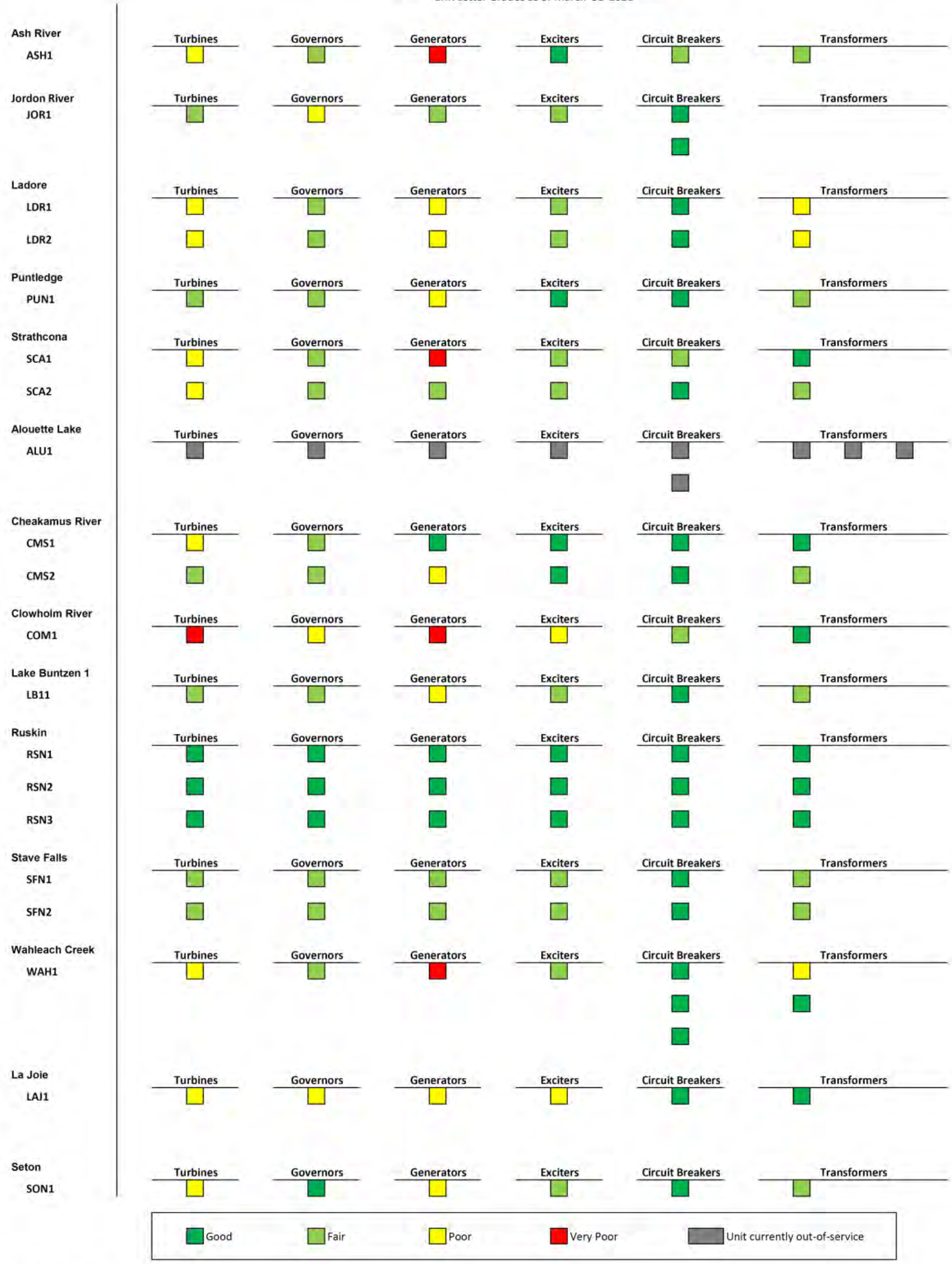
Asset Health Ratings for Generation assets as of March 2021 are provided below.



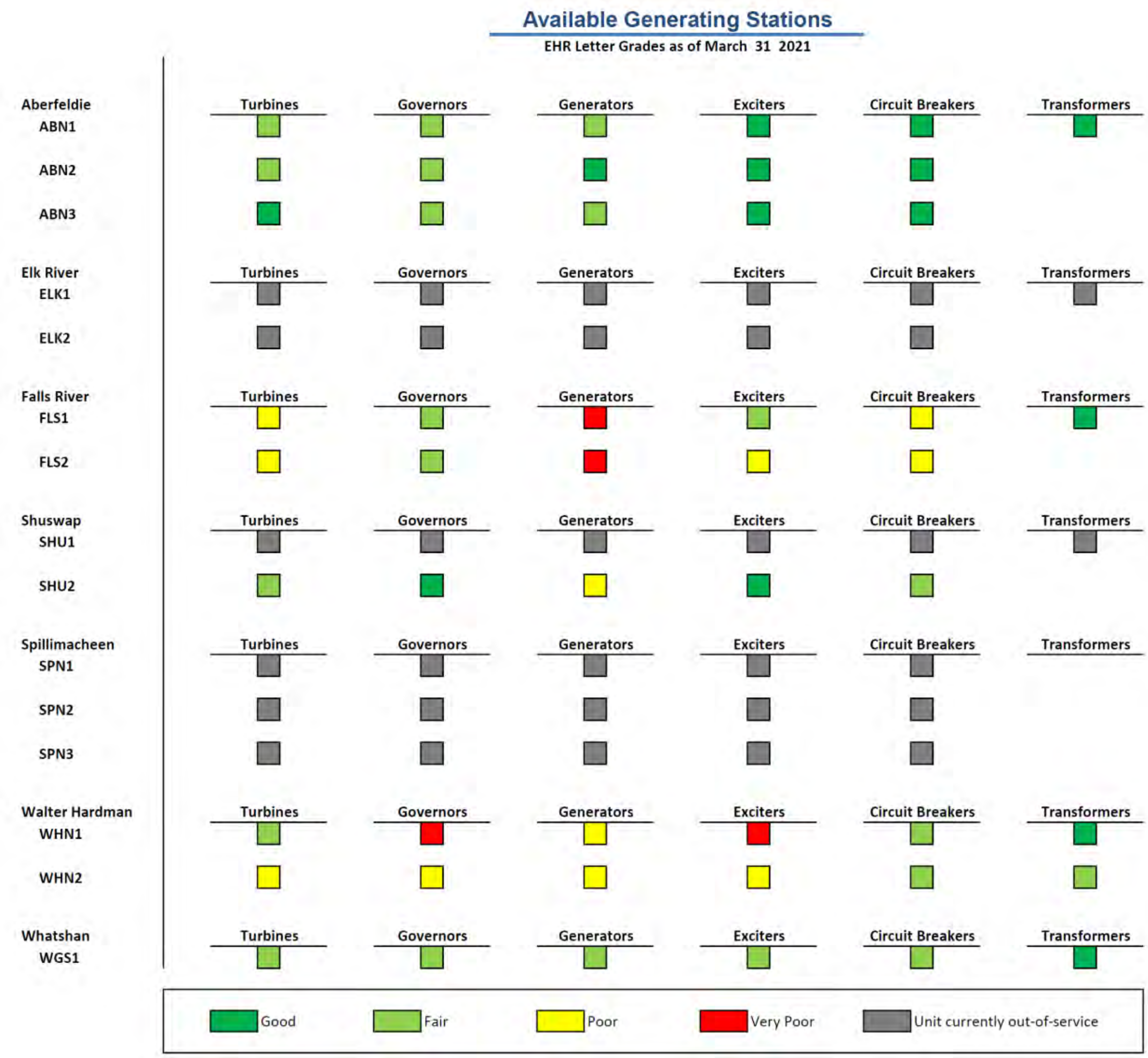
Note: Condition assessments for the newly constructed Mica (MCA) generating station Unit 6 assets are underway will be completed in 2021. Waneta (WAN) generating station is leased to Teck Metals Limited until 2038 and Teck is responsible for the management of the assets and therefore BC Hydro's Asset Health Ratings do not apply at this time.

Strategic Generating Stations

EHR Letter Grades as of March 31 2021



Note: The assets related to the three new units at the John Hart New (JHN) generating station are not currently included in BC Hydro's Asset Health Rating system. The assets are maintained by InPower BC under the terms of an operating agreement out to 2033.


Available Generating Stations
EHR Letter Grades as of March 31 2021
Aberfeldie
ABN1
ABN2
ABN3
Elk River
ELK1
ELK2
Falls River
FLS1
FLS2
Shuswap
SHU1
SHU2
Spillimacheen
SPN1
SPN2
SPN3
Walter Hardman
WHN1
WHN2
Whatshan
WGS1
Turbines
Governors
Generators
Exciters
Circuit Breakers
Transformers
Good
Fair
Poor
Very Poor
Unit currently out-of-service

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix M

Asset Health – Transmission and Distribution

Table of Contents

List of Tables

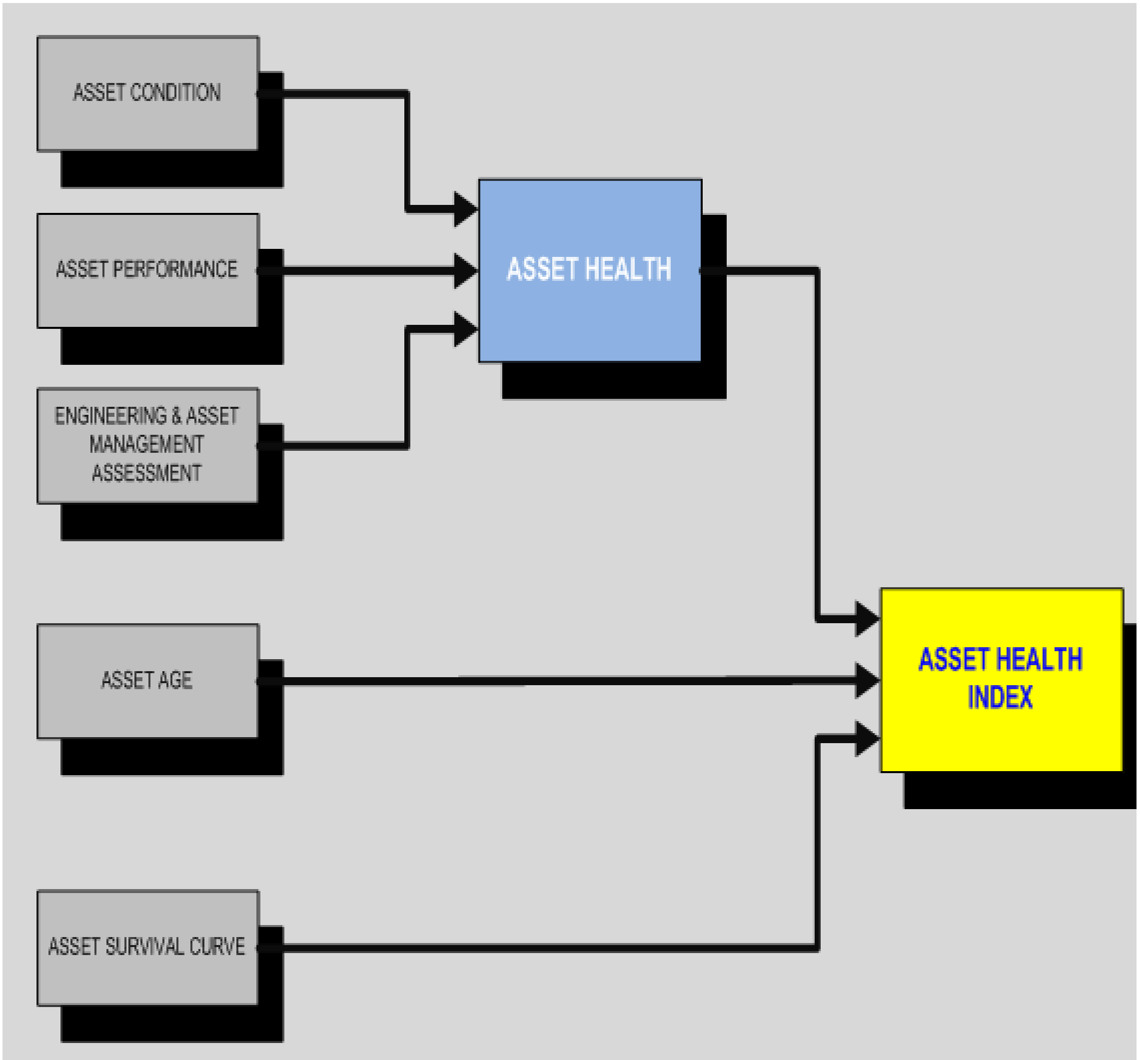
1 Introduction

BC Hydro assesses the asset health of its Generation, Transmission and Distribution assets to inform the life-cycle management of the assets, including supporting the need for capital investments. BC Hydro uses two asset health methodologies, each of which provide a systematic, objective, repeatable, and transparent assessment of asset health:

BC Hydro uses a methodology called Asset Health Index to evaluate the health of Transmission and Distribution assets. For reporting purposes, results are presented using a common Asset Health Rating for Generation, Transmission and Distribution assets on a scale of Good, Fair, Poor and Very Poor.

2 Transmission and Distribution Asset Health

The Asset Health Index is derived from maintenance and asset management data. The methodology is illustrated below.



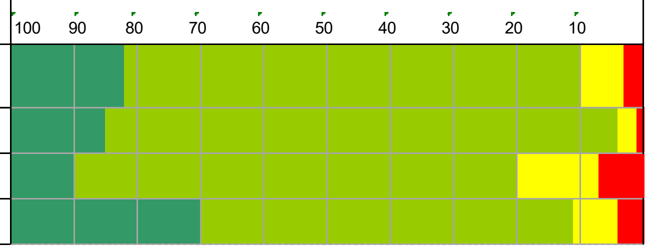
1 Asset Health Ratings and possible investment needs are:

	Description
Good	As new condition, with no noticeable deterioration or defects
Fair	Normal deterioration of the asset with one or more minor defects; function is not affected
Poor	Serious deterioration of the asset or serious defects
Very Poor	Extensive serious deterioration of the asset or asset function is affected

Asset Health Rating can be grouped and analysed by asset class and/or criticality. Below are Asset Health Rating charts for Transmission and Distribution asset classes as of March 2021.

Table M-1 Asset Health Rating Summary

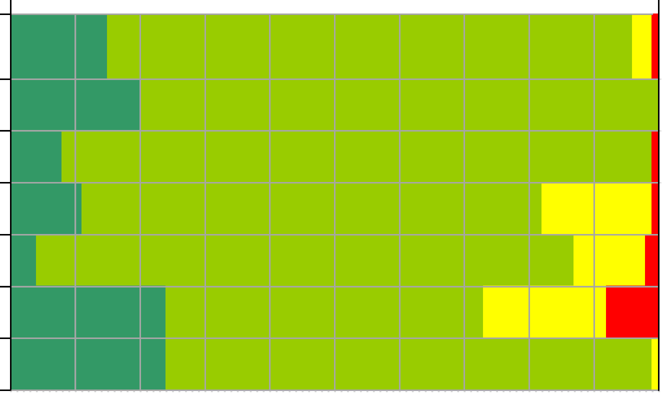
T&D Assets	Number of Assets	% of Asset Replacement Value
T&D Assets - 39 Asset Classes	4,173,150	
Transmission - 6 Asset Classes	124,586	
Substation - 20 Asset Classes	58,074	
Distribution - 13 Asset Classes	3,990,490	



Good Fair Poor Very Poor

Table M-2 Asset Health Rating for Transmission Line Assets

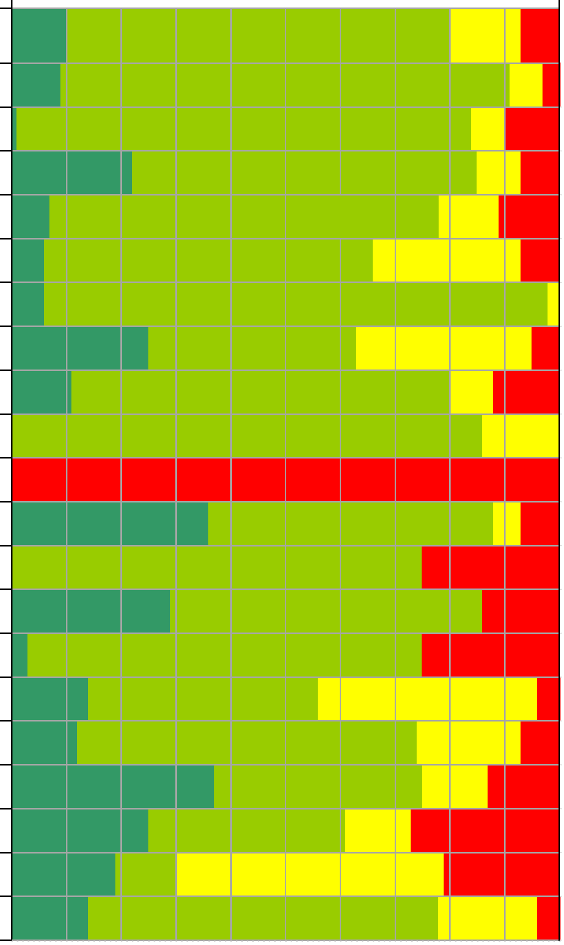
All Transmission Assets	Number of Assets	% of Asset Replacement Value
All Transmission Assets	124,585	
1 - Metal Support Structures	26,432	
2 - Conductor Systems (km)	19,726	
3 - Wood Pole Structures	77,499	
4 - Underground Cables (km)	346	
5 - Line Disconnect Switches	263	
6 - Others	319	



Good Fair Poor Very Poor

Table M-3 Asset Health Rating for Substation Assets

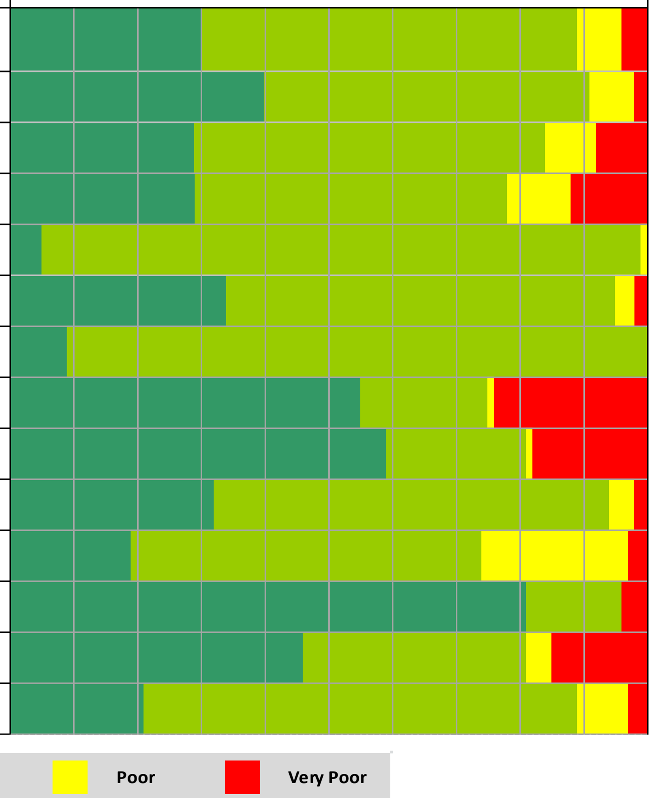
All Substation Assets	Number of Assets	% of Asset Replacement Value
All Substation Assets	58,074	
1 - Transformers	1,480	
2 - Gas Insulated Switchgear	540	
3 - Circuit Breakers	4,002	
4 - Reactors	1,983	
5 - Protection & Control Relay Systems	15,385	
6 - Shunt Capacitors	434	
7 - Disconnect Switches	14,439	
8 - Instrument Transformers	8,593	
9 - Series Capacitors	14	
10 - HVDC Pole 2 (To be decommissioned)	1	
11 - Surge Arrestors	6,559	
12 - Synchronous Condensers	4	
13 - Static VAR Compensator	5	
14 - Station Insulators	434	
15 - Standby Generators and Fuel Systems	77	
16 - Batteries	344	
17 - Mobile Transformers & Mobile Unit Substations	8	
18 - Fire Protection Systems	176	
19 - Voltage Regulators	371	
20 - Others	3,225	



Good Fair Poor Very Poor

Table M-4 Asset Health Rating for Distribution Assets

Distribution	Number of Assets	% of Asset Replacement Value
All Distribution Assets	3,990,490	
1 - Distribution Poles	894,247	
2 - Underground Transformers	70,609	
3 - Overhead Transformers	285,649	
4 - Overhead Primary Conductors (km)	47,740	
5 - Underground Primary Cables (km)	11,242	
6 - Revenue Meters	2,120,073	
7 - Cutouts	414,534	
8 - Overhead Switches	13,073	
9 - Overhead Reclosers	1,567	
10 - Street Lights	91,623	
11 - Voltage Regulators	613	
12 - Capacitors	252	
13 - Others	39,268	



BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix N

Capital Planning and Delivery Processes

Table of Contents

List of Figures

List of Tables

1 BC Hydro's Capital Investment Planning Process

This section describes BC Hydro's enterprise wide capital planning process for capital investments and how this process is applied to create the Capital Plan which forms the basis for the capital-related evidence contained in this application.

BC Hydro has planning and governance processes in place across the organization so that the capital investments required to sustain, expand and operate its assets appropriately balance affordability and system performance.

This section is organized around the following points:

- Section 1.1 discusses how BC Hydro's Enterprise Capital Planning Process facilitates the use of a common approach to planning, prioritizing and governing investments across the company.
- Section 1.2 discusses how BC Hydro's Executive Team sets the strategic direction and priorities for the annual capital planning process.
- Section 1.3 explains how the bottom up planning process is used for each of the asset categories.
- Section 1.4 discusses how BC Hydro uses a collaborative approach to review the capital portfolios across the enterprise and to develop the Capital Plan.
- Section 1.5 explains that BC Hydro has robust processes for the governance, oversight and ongoing management of the Capital Plan.

In 2017, BC Hydro established an Enterprise Capital Planning Working Group. The purpose of the Enterprise Capital Planning Working Group is to apply a common approach to planning, prioritizing and governing investments across the company. The Enterprise Capital Planning Working Group has representatives from the major portfolios included in BC Hydro's capital planning process which are: Integrated Planning, Properties, Technology, Finance and Fleet Services.

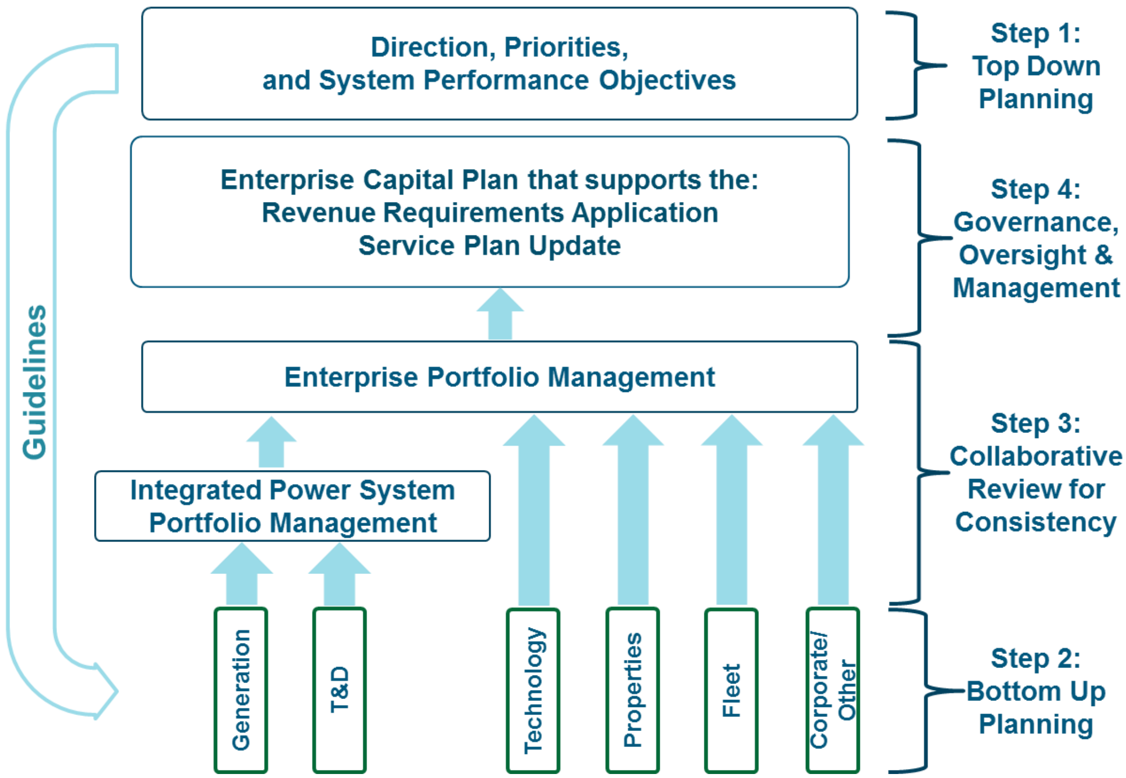
BC Hydro must be flexible and responsive to the investment needs of the system. The Enterprise Capital Planning Working Group manages the annual capital planning process so that the Capital Plan is updated and prioritized to respond to the latest information on the system risks and needs.

1.1 The Capital Planning Process and Deliverables are Clearly Articulated

The enterprise wide capital planning process that is overseen by the Enterprise Capital Planning Working Group is clearly defined and the deliverables are well understood by the relevant areas of the business.

Figure N-1 below provides a simplified depiction of our capital planning process and identifies major outcomes and deliverables of the process. Each step of the process is described in the following sections.

Figure N-1 Annual Enterprise Capital Planning Process



1.2 Step 1- Top Down Planning

A key element of the annual enterprise capital planning process is the direction provided by the Executive Team on long-term capital investment levels. In providing this direction the Executive Team considers BC Hydro's capital investment needs while balancing affordability, system performance and the need to manage the risks of our assets.

1.3 Step 2 – Bottom Up Planning

Once the long-term capital investment levels have been established, preliminary financial targets are developed for each of the asset categories considering the factors discussed in Step 1, as well as the historical composition of the capital plan.

These preliminary financial targets are an input into the bottom-up planning process, as shown in Figure N-1 above.

Within the common Enterprise Capital Planning process, each asset category uses a bottom-up planning process that is tailored to the characteristics of the portfolio, considering:

- The function, criticality, volume and complexity of the different assets;
- The magnitude of the risks, issues and opportunities;
- The size, scope, complexity and costs of the capital investments; and
- The internal stakeholders that should be involved in the process.

The processes used for the asset categories are scaled as required. For example, the largest and most complex portfolios such as Generation or Transmission and Distribution, which collectively comprise the Power System, generally require more complex and detailed planning processes, and involve a broader discussion with internal stakeholders across BC Hydro.

1.4 Step 3 – Collaborative Review for Consistency

Once bottom up planning has concluded, capital planning information is consolidated for:

- Collaborative peer reviews at the enterprise level;
- Validation of alignment with BC Hydro’s strategic direction and priorities; and
- Identification of any potential areas for improvement in the process for the next annual capital planning cycle.

Peer reviews are conducted by the Enterprise Capital Planning Working Group, before the enterprise capital plan is submitted to BC Hydro’s Executive Team and Board of Directors. Generally, these reviews focus on three main areas:

- An overall summary of each asset category portfolio;
- The quality of information used to develop the Capital Plan; and
- The risk profile of the consolidated Capital Plan.

The risk profile of the Capital Plan is based on BC Hydro's enterprise-wide framework for capital prioritization. This framework describes the assessment and prioritization process related to proposed capital investments. Investments are assessed based on the primary driver of the proposed investment, as follows:

- Investments that primarily mitigate risk are scored for prioritization using a methodology that is aligned with the BC Hydro Corporate Risk Matrix; and
- Investments that primarily create value are scored for prioritization using a net value per dollar invested metric. The value prioritization is mainly used for Technology capital expenditures expected to enhance business capability.

Through BC Hydro's enterprise-wide framework for capital prioritization, capital investments are classified into one of three categories:

- Mandatory investments driven by legal and regulatory requirements;
- Committed investments not to be postponed. This category includes projects that were prioritized in previous capital plans and are now economically unreasonable to cancel; and
- Investments to be prioritized. This category includes projects that could be re-prioritized without significant costs.[1]

[1] Risk scores are included on appendix I for to be prioritized investments.

1.5 Step 4 - Oversight and Review

The final step in BC Hydro's annual enterprise capital planning process is the review and approval of the Capital Plan by the Executive Team and Board of Directors, which occurs as part of the annual budget and five-year forecast approval process. This review is conducted to assess whether the plan meets overall business objectives and provides a consistent and appropriate management of risks across all asset categories.

Once the Capital Plan is approved by the Executive Team, it is monitored, on an ongoing basis, by the Capital Delivery Management Committee. The committee focuses on the early years of the Capital Plan so that actual and forecast capital expenditures remain aligned with the original Capital Plan. This management is done at a portfolio level so that, if required, adjustments can be made to re-direct the capital budget, as new information becomes available. To make these decisions, the committee considers financial impacts, the enterprise risk profile, and labour resource availability.

Decisions to reallocate the budget within the Capital Plan are governed through an ex-plan governance process, which considers the size of the ex-plan request. Requests less than $3 million are reviewed at the Enterprise Capital Planning Working Group level, while requests greater than $3 million are reviewed and approved at the Capital Delivery Management Committee level. Reallocations may result in the approval of new projects to address emerging issues, the advancement of future investments based on new information or the increase of funding to existing programs, in response to identified needs.

2 Power System Assets Planning & Delivery Processes

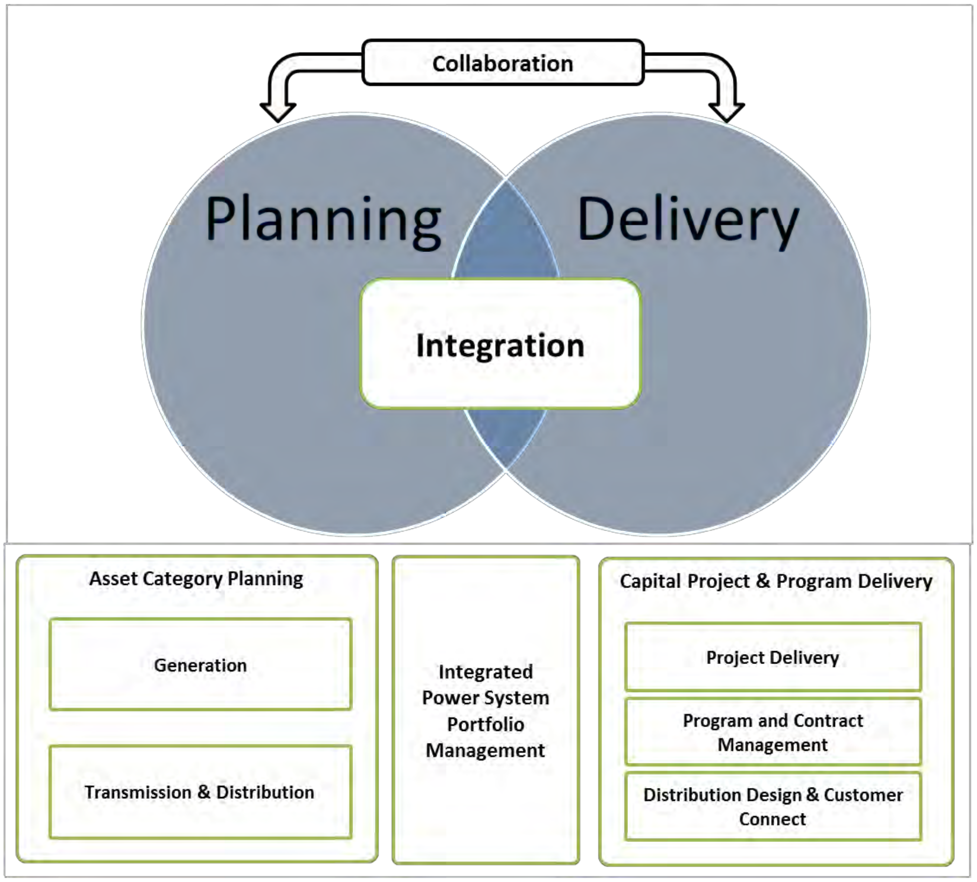
The Power System includes BC Hydro's Generation, Transmission and Distribution assets.

Over time, the condition and performance of existing assets degrade, regulatory and safety requirements change, and new assets are required to address load growth and connect new customers. Together, these factors create issues, risks and opportunities to be addressed through capital investment.

The planning and delivery processes for the Power System are integrated, requiring a high degree of collaboration across the organization.

Figure N-2 below represents a high-level depiction of the interaction between functional groups responsible for asset management and planning, and portfolio delivery when planning and delivering capital investments for the Power System.

Figure N-2 Integrated Power System Planning and Delivery



Planning processes are in place to understand the issues, risks and opportunities associated with the assets and to identify the recommended capital investments.

- Sections 2.1 to 2.4 provide further information on the Power System assets, the bottom-up planning processes for each asset category and the integrated portfolio planning process for the Power System; and
- Sections 2.5 to 2.6 provide an overview of the collaboration and integration between planning and delivery through the annual capital planning process, the work planning process and the release of projects and programs to the Key business Units (**KBUs**) responsible for delivery.

Delivery processes are in place to deliver projects and programs on time and on budget, and within scope. Investments associated with the Power System are delivered by three different KBUs: Project Delivery, Program and Contract Management and Distribution Design and Customer Connect.

- Sections 2.7 to 2.9 explain the project delivery practices used to deliver those investments;
- Section 2.10 describes the financial approval policies and procedures applicable to all capital investments; and
- Section 2.11 describes our portfolio risk adjustment.

2.1 Generation Assets Capital Investments

Capital investments in generation assets include asset sustainment, dam safety and growth investments.

2.1.1 BC Hydro Prudently Manages Generation Assets Over Their Lifecyle

BC Hydro's generation assets are aging, and a number of generation assets are now at end of life. BC Hydro's generation assets include 83 generating units at 30 hydroelectric generating facilities as well as 85 dams located at generating stations and at additional locations to provide water storage and water diversion functions. Generation assets also include three gas-fired units at BC Hydro's two thermal generating stations and four synchronous condenser units at a dedicated synchronous condenser station. BC Hydro also has 17 diesel generating stations and one hydroelectric generating station in areas not connected to the integrated electric system.

Construction of most of BC Hydro's large capacity generating facilities occurred in the 1960s, 1970s and 1980s, while the majority of BC Hydro's medium capacity facilities were constructed in the 1950s. Asset Health assessments indicate that a number of generation assets are now at end of life. An overview of generation asset health is provided in Appendix L.

BC Hydro manages its generation assets over their lifecycle by:

- Maintaining the assets so that they perform safely and reliably throughout their operating lives;
- Investing in the assets to extend their operating lives, enhance capability, manage risk, and increase efficiency and cost-effectiveness; and
- Managing public and worker safety risks associated with facilities, especially around reservoirs and dams.

Planning processes are in place to support these objectives and to align the portfolio of investments to effectively manage risk and customer needs within financial and labour resource constraints.

With the exception of the Site C Clean Energy Project, which is a growth project, the majority of capital investments in the Generation portfolio are driven by the need to address issues and risks associated with existing facilities. These investments are categorized as Generation Asset Sustainment and Dam Safety investments. The following sections describe BC Hydro’s Generation Asset Sustainment and Dam Safety portfolios in more detail and then explain BC Hydro’s bottom-up planning process for generation assets.

2.1.2 Generation Asset Sustainment Addresses the Highest Risks

Generation sustainment capital investments mitigate or resolve the highest risks identified with BC Hydro’s generation assets. The risk assessment considers how important generation facilities are to the overall system, as well as the asset condition.

BC Hydro's generation facilities are categorized as "Key", "Strategic" or "Available", according to the significance of the facility to BC Hydro's system. An investment strategy is in place for each category which reflects the significance of the category of facility to the power system. Table N-1 below provides a list of BC Hydro's generation facilities by category.

Table N-1 BC Hydro's Generating Facilities by Category

Facility Abb'n	Facilities	Facility Category	Year of Initial Operation	Current Age (Years) 2021	Current Maximum Capacity (MW)	Number of Units
BRR	Bridge River 1 & 2 (Originally developed 1934)	Key (Hydro)	1948	73	495	8
GMS	GM Shrum	Key (Hydro)	1968	53	2916	10
KCL	Kootenay Canal	Key (Hydro)	1975	46	582	4
MCA	Mica	Key (Hydro)	1976	45	2781	6
PCN	Peace Canyon	Key (Hydro)	1980	41	736	4
REV	Revelstoke	Key (Hydro)	1984	37	2368	5
SEV	Seven Mile	Key (Hydro)	1979	42	817	4
WAN	*Waneta (Acquired 2018)*	*Note 1*	*1954*	*67*	*492*	*4*
ALU	Alouette	Strategic (Hydro)	1928	93	0	1
ASH	Ash River	Strategic (Hydro)	1959	62	26	1
CMS	Cheakamus	Strategic (Hydro)	1957	64	192	2
COM	Clowhom	Strategic (Hydro)	1957	64	30	1
JHN	John Hart (Originally developed 1947)	Strategic (Hydro)	2018	3	135	3
JOR	Jordan River (Originally developed 1912)	Strategic (Hydro)	1971	50	167	1
LAJ	La Joie	Strategic (Hydro)	1957	64	22	1
LB1	Lake Buntzen (Originally developed 1903)	Strategic (Hydro)	1951	70	60	1
LDR	Ladore	Strategic (Hydro)	1956	65	52	2
PUN	Puntledge (Originally developed 1912)	Strategic (Hydro)	1955	66	26	1
RSN	Ruskin (Originally developed 1930)	Strategic (Hydro)	2016	5	106	3
SCA	Strathcona	Strategic (Hydro)	1958	63	63	2
SFN	Stave Falls	Strategic (Hydro)	1999	22	90	2
SON	Seton	Strategic (Hydro)	1956	65	44	1
WAH	Wahleach	Strategic (Hydro)	1952	69	61	1
FNG	Fort Nelson	Strategic (Thermal)	1999	22	72	2
RPG	Prince Rupert Gas	Strategic (Thermal)	1973	48	46	2
BSY	Burrard Synchronous Condenser [note 2]	Strategic (Synchronous Condenser)	1962	59	N/A	4
ABN	Aberfeldie (Originally developed 1922)	Available Energy (Hydro)	2008	13	25	3
ELK	Elko	Available Energy (Hydro)	1924	97	11	2
FLS	Falls River	Available Energy (Hydro)	1930	91	7	2
SHU	Shuswap	Available Energy (Hydro)	1929	92	6	2
SPN	Spillimacheen	Available Energy (Hydro)	1955	66	5	3
WGS	Whatshan (Originally developed 1951)	Available Energy (Hydro)	1972	49	60	1
WHN	Walter Hardman	Available Energy (Hydro)	1960	61	10	2
Note 1	On July 26, 2018, BC Hydro became the sole owner of Waneta. Teck Metals Ltd ("TML") continues to act as the Operator of the facility during the 20 year lease term, and is required to operate, manage, and maintain Waneta in accordance with the terms of the Co-Possessors and Operating Agreement ("COPOA").					
Note 2	Burrard Synchronous Condenser facility was previously the Burrard Thermal generating facility.					

- **"Key" generating facilities:** Seven "Key" generating facilities represent the largest hydro-electric facilities on the BC Hydro system and produce approximately 90 per cent of BC Hydro's average annual energy;
- **"Strategic" facilities**: Eighteen "Strategic" facilities represent all generating stations on Vancouver Island, all stations located on cascading systems, all thermal generation stations and generating stations required to provide voltage support to the transmission network. These facilities produce approximately 9 per cent of BC Hydro's average annual energy and provide significant additional value to BC Hydro due to their geographic location and system support services;
- **"Available" facilities:** Seven "Available" facilities represent those facilities that are of lower strategic importance and produce less than 1 per cent of BC Hydro's average annual energy; and
- **Waneta two-thirds:** On July 26, 2018, BC Hydro became the sole owner of Waneta. Teck Metals Ltd. continues to act as the Operator of the facility during the 20-year lease term. In that role, Teck is required to operate, manage, and maintain Waneta in accordance with the terms of the Co-Possessors and Operating Agreement (**COPOA**), which includes capital planning and operating to a prudent owner standard, exercising the degree of care and skill of an experienced dam operator and acting in accordance with Good Utility Practice.

  As Teck is the Operator of Waneta, processes that BC Hydro generally uses for internal asset management and planning purposes will not be applied. BC Hydro will retain an oversight role as part of the Waneta Operating Committee, including reviewing the annual operating plans for Waneta.

The condition of assets across BC Hydro's generation fleet is a foundational input to the planning process. BC Hydro evaluates the condition of its major equipment (turbines, generators, governors, exciters, transformers, and circuit breakers) based on the latest available maintenance test and inspection data, following BC Hydro's Equipment Health Rating methodology. This provides a systematic, objective, repeatable, and transparent assessment of equipment health. Factors influencing the Equipment Health Rating include:

- Equipment health;
- Maintenance history;
- Equipment reliability;
- Availability of spare parts;
- Availability of technical support; and
- Known equipment type design problems.

Asset health or condition information is used to assess and manage risk and to prioritize the need to make investments to preserve and sustain the generating units. Each health assessment results in a rating of Good, Fair, Poor, or Very Poor.

2.1.3 Dam Safety Investments Focus on Key Areas of Risk

BC Hydro's dams are subject to the British Columbia *Dam Safety Regulation*, which defines a "Dam" as:

(a) A barrier constructed for the purpose of enabling the storage or diversion of water diverted from a stream or an aquifer, or both; and

(b) Other works that are incidental to or necessary for the barrier described in paragraph (a).

Consistent with the *Dam Safety Regulation*, BC Hydro's Dam Safety portfolio comprises all physical features, structures and mechanisms - both constructed and natural - that retain the reservoirs and control the passage of flows past the dam.

The *Dam Safety Regulation* classifies dams according to the consequences of their failure, such as the potential for loss of life, environmental damage and economic impacts. Classifications range from “Low Consequence” to “Extreme Consequence”. These classifications dictate the required frequency of safety activities performed on the dam and are further used to guide the selection of the dam’s design and performance criteria.

Dam Safety issues and risks involve:

- The safe storage and controlled passage of water under normal conditions;
- The ability to pass floods (from the annual freshet to extreme events); and
- The ability to withstand a major earthquake without any harmful release of water.

Dam Safety risks generally have a low probability of occurrence but, if realized, a high consequence. Key drivers of Dam Safety capital investments include:

- ***Seismic Risk:*** The Canadian Dam Association Guidelines provide recommended seismic performance criteria for regulated dams based on their consequence classification. The guidelines define target performance levels in terms of an Annual Exceedance Probability (AEP). The expectation is that a dam will have no uncontrolled release of the reservoir during and following earthquake ground motions that would be expected to occur on that site no more than the frequency defined by the target AEP. Capital investments to upgrade a dam are sometimes required to improve its seismic performance to meet current Canadian guidelines.
- ***Reliability of Spillway Gates:*** A spillway is an essential component of any dam facility. It provides a means for passing sufficient quantities of water from the reservoir to the downstream water course when power generation is unavailable or insufficient to maintain required downstream flows or prevent the

reservoir from rising above its maximum safe elevation. Discharge through a spillway may also be required for emergency reservoir drawdown, such as if a defect develops within the dam and there is a need to reduce the load on the dam. Discharge through a spillway is regulated by gates located at its upstream end. BC Hydro assesses its spillway gates for design or condition-based deficiencies that impinge upon their operational reliability and which, due to their critical safety function, pose a risk. Once identified, those risks are prioritized and addressed through investments in the dam safety portfolio.

- ***Condition of Civil Structures:*** Over time and due to wear and tear the integrity or degradation of the existing civil structures poses a risk to the ability to store or pass water safely. For example, reservoir booms naturally deteriorate over time. Poorly functioning booms can allow large debris in the reservoir to reach the dam, blocking spillways and other water passages and interfering with or preventing the proper function of these critical features of a dam. These and other deficiencies are prioritized and addressed through investments in the dam safety portfolio.
- ***Condition and Function of Water Passages:*** Over time degradation of the existing water passages poses a risk to the ability to pass water safely. For example, steel penstock coatings degrade over time and, if not addressed, lead to metal loss and loss of integrity of the penstock. Furthermore, passage of water under a variety of operational and upset conditions must be managed to protect people, assets, and the environment. Upgrades to penstocks, intake gates, valves and their associated monitoring and controls are prioritized through investments in the dam safety portfolio.

2.2 Generation Bottom-Up Capital Planning Process

The following sections describe the steps of BC Hydro's bottom-up capital planning process for generation assets.

2.2.1 Step 1 - Generation Strategic Asset Management Plan

First, BC Hydro considers its Generation Strategic Asset Management Plan. This plan sets out ten-year strategies for each facility category – Key, Strategic and Available - to support appropriate resource allocations and performance targets for the facilities.

- **Key facilities:** BC Hydro has implemented a component replacement strategy for its Key facilities. Under this strategy, all major equipment at Key facilities will be restored to Good or Fair condition or will have work underway to restore them to Good or Fair condition, within ten years. This strategy means that, in aggregate, the reliability of Key facilities will be maintained at or slightly above the average of similar facilities, as reported by the Canadian Electricity Association;
- **Strategic facilities:** Equipment in "Poor" or "Very Poor" condition at Strategic facilities will either be refurbished or replaced within ten years, will have work underway to be refurbished or replaced within ten years or will have a long-term plan developed to mitigate the risk of equipment failure. This strategy means that, in aggregate, the reliability of Strategic facilities will be maintained at or restored to the average of similar facilities, as reported by the Canadian Electricity Association; and
- **Available facilities**: With the exception of Whatshan and Aberfeldie (the largest and newest Available facilities) all other Available facilities will receive minimal capital investment and will be taken out of service when they are no longer able to safely generate electricity. BC Hydro will perform regular

maintenance and inspection on these assets to keep them safe and inform investment and operating decisions. Options to re-furbish, re-develop or decommission Available energy facilities that have been taken out of service will be developed as required. Decisions on these options will be informed by BC Hydro's long-term load resource balance. Over time, this strategy may result in a gradual reduction of the energy produced by Available facilities.

2.2.2 Step 2 - Dam Safety Investment Strategy

Second, BC Hydro's level of investment in Dam Safety is targeted to address identified deficiencies in the dams and their appurtenant structures so that:

- There is no significant deterioration of BC Hydro's overall risk position with respect to these assets; and
- The overall level of risk is kept well within tolerable limits as guided by the Canadian Dam Association's Dam Safety Guidelines and the International Commission on Large Dams' Bulletin on Dam Safety Management.

In addition, BC Hydro's dam safety investments also consider qualitative judgements made, on a case by case basis, with regulators and government representatives, First Nations and stakeholders.

This targeted level of investment accounts for both the experienced and expected future wear and tear of the dams, identification of new issues, and improved understanding of previously identified issues through engineering investigations.

Identified deficiencies are rated by a "Vulnerability Index"[2] that considers:

- The extent to which the design or performance of a particular dam feature (deficiency) differs from accepted good practice;

[2] Further information on the Dam Safety Vulnerability Index is included in Appendix FF - Long-Term Dam Safety Plan.

- The extent to which that feature contributes to the safe performance of the dam;
- The frequency at which the feature is potentially stressed to the limits of its performance; and
- The effectiveness of any interim risk controls that might be in place.

At each dam, issues and risks are grouped to form a project or set of projects based on asset type, similarity of issues or solutions, and location within the facility or system. These projects are then prioritized across the system by considering:

- The potential reduction of the Vulnerability Index;
- The consequence classification of the dam;
- The cost and time to effect remediation compared to the benefits from risk reduction;
- The sequencing of required enabling projects; and
- The completeness of BC Hydro's understanding of the issue and potential remediation.

In addition to the considerations above, the Dam Safety investment strategy must provide for inclusion of investments for improvements of infrastructure deficiencies, such as those that enable access, monitoring, and management of hazards at BC Hydro's dam sites.

2.2.3 Step 3 - Growth Driven Generation Investments

Third, BC Hydro identifies opportunities to enhance the capability or increase the efficiency of existing facilities. Generation growth investments are integrated into the Capital Plan when there is an identified need for increased energy or capacity resources.

2.2.4 Step 4 - Facility Asset Plans

Fourth, BC Hydro considers the Facility Asset Plans for its hydroelectric generating facilities, thermal generating and synchronous condenser stations. Facility Asset Plans formulate, document and recommend a ten-year investment strategy for each facility, with a focus on the near years of the plan. These strategies account for the facility's role in BC Hydro's system, its Asset Health Ratings, dam safety issues and deficiencies, performance levels and targets, risks, and growth opportunities. Capital upgrade projects to implement these strategies are carefully planned so that unit outages and maintenance work are coordinated with power system requirements.

As they are developed, each Facility Asset Plan is presented to the Asset and Risk Planning Committee for agreement in principle and endorsement. This committee provides input to the Facility Asset Plan on all issues, risks and planned investments.

Facility Asset Plans are updated periodically to reflect the latest information, including changes in priorities and strategies which influence the scope and timing of facility plans and investments. A Facility Asset Plan may also be updated if new information emerges that affects the investment strategy for the facility. Between updates, BC Hydro continues to monitor the risks and issues associated with the facilities and makes adjustments, if needed.

Summaries of Facility Asset Plans are provided in Appendix K – Summaries of Capital Project, Strategies Plans and Studies.

2.2.5 Step 5 – Annual Capital Planning Review

Fifth, as part of the annual capital planning process, BC Hydro undertakes a review of the planned investments for each facility. Investments are reviewed to check that the facility asset planning process has been applied consistently, the data quality is sufficient, and the investments are appropriately prioritized and timed. These investments are then submitted into the Integrated Power System Portfolio Management process, as described in section 2.5 below.

2.3 Transmission and Distribution Assets Capital Investments

The following sections describe the needs, risks and opportunities that are driving investment requirements on BC Hydro's transmission and distribution assets including substations.

2.3.1 Transmission and Distribution Assets Are Aging and Many Require Investment in the Near Term

BC Hydro's transmission and distribution assets are aging, and the asset health assessment of these assets indicate that a number of them are now at end of life.

BC Hydro's transmission and distribution assets include over 18,000 circuit km of transmission overhead lines, approximately 350 km of transmission subterranean and submarine cables, 323 substations, an integrated telecommunication system, approximately 49,000 circuit km of distribution primary overhead lines and 11,000 circuit km of distribution primary underground lines. Overall, BC Hydro has approximately four million individual transmission and distribution assets.

A large portion of the transmission system was built in the 1960s and 1970s and these assets are, or soon will be, reaching or exceeding end-of-life condition. Similarly, a large portion of the distribution system has, or soon will be, exceeding its design life. Asset Health assessments indicate that a portion of the transmission and distribution assets are in Poor to Very Poor condition, which requires either remediation work or replacement within the next ten years. This is to be expected that a certain portion of assets will be in Poor or Very Poor condition at any point in time. An overview of transmission, distribution and substation asset health is provided in Appendix M.

BC Hydro has established planning processes in place to:

- Develop transmission and distribution system plans for the safe and reliable delivery of electricity to customers;
- Connect new customers and distributed generation;
- Expand networks with existing capacity constraints to meet anticipated load growth;
- Manage asset performance; and
- Meet regulatory requirements.

Sustainment expenditures are made so that the assets perform as required throughout their lifecycle. Investments in existing assets include activities such as:

- Replacement of assets based on condition;
- Enhancements to maintain or improve customer reliability and extend asset life;
- Upgrades to mitigate risks including safety, environment, security and seismic;
- Improvements to meet evolving regulatory standards; and
- Relocations to address third-party requests.

2.3.2 BC Hydro Is Continuing to Replace Existing Assets

Assets are replaced when the equipment performance can no longer be managed due to comparatively high cost, lack of parts, or inadequate manufacturer support. Asset replacements are also required to mitigate increasing public and worker safety risks as well as environmental and regulatory risks, which could result from asset failures.

The Asset Health Index is used to assess the condition of the transmission and distribution assets. This approach considers factors such as asset age and available test and inspection data. For reporting purposes, results are presented using a common Asset Health Rating scale of Good, Fair, Poor and Very Poor. These ratings can be grouped and analyzed to assist with investment decisions.

Most replacements are the result of proactive inspections and maintenance. For example, cedar wood poles are tested and treated 20 to 29 years after initial installation and then every ten years thereafter. Units that fail the test criteria are then scheduled for replacement.

In cases where the impacts of asset failure on customer reliability are low and proactive maintenance is ineffective in extending asset life, a 'run to failure' strategy is used to minimize the life cycle costs of managing the assets. Examples of asset classes that are 'run to failure' include new LED street lights that will operate without maintenance (other than one mid-life cleaning) over their useful lives.

2.3.3 Customer Reliability Investments Are Aimed at Managing Current Reliability Levels

Customer reliability investments include upgrades to existing assets as well as adding new assets to manage reliability. Customer reliability capital expenditures are required during the test period to manage current levels of system performance. Examples of customer reliability projects include backup circuit ties to enable faster restoration in the event of customer outages as well as circuit re-locations and re-configurations to avoid potential outage causes, such as tree and vegetation contacts.

2.3.4 A Portion of the Sustainment Budget is Directed at Mitigating Other Risks

A portion of the transmission and distribution capital investment portfolio is to address a variety of other risks including public and worker safety, environment, fire, security, seismic and extreme weather. This includes:

- **Safety risk mitigation**: Examples of safety projects include the replacement of H-Frame structures in the alleys of downtown Vancouver that pose a public safety risk due to reduced clearances to buildings, and the replacement of pad mounted distribution live-front switchgear that may pose a safety hazard to employees operating them as the switchgear reaches end of life.
- **Environmental risk mitigation**: Examples of environmental projects include those to manage oil-filled equipment to address the Federal *PCB Regulations* deadline of December 31, 2025 and avoid the risk of spills as well as projects to modify structures in areas where protected bird species congregate in order to avoid electrical contact incidents.
- **Fire and security risk mitigation**: Examples of projects to address fire and security risk at substations include the installation or upgrading of fire protection systems or the installation of access detection and control, video monitoring, perimeter fencing and gate upgrades.
- **Extreme weather risk mitigation**: Examples of projects to address risks related to extreme weather include installing piles, reinforcing foundations and constructing protective structures such as retaining walls, riprap berms and debris deflectors around transmission structures and their foundations, to withstand storms, floods, landslides, and avalanches.

2.3.5 Growth Investments Have Multiple Drivers

Growth expenditures are required to expand the transmission and distribution system to accommodate load growth, to connect new customers and to mitigate other risks. This type of investment includes:

- Upgrades and additions of station equipment;
- Upgrades and additions of transmission lines and distribution feeders; and
- New service connections and upgrades.

Demand for electricity continues to increase in some areas of the province and certain parts of the BC Hydro system are reaching capacity. In certain sectors of the economy, such as the oil and gas sector in the Peace and North Coast regions, economic growth is driving the need to reinforce the system in areas that do not have the infrastructure to meet the emerging demand. In addition, new investments continue to be required to connect new customers to the BC Hydro system.

Growth investments and their timing are informed by forecast load growth, resource supply additions and existing system capacity.

Capital investments to interconnect transmission customers are also difficult to forecast. Due to uncertain timing, location and scope, only known transmission customer interconnection projects are included as specifically identified projects in the forecast capital expenditures for the test period.

BC Hydro also includes provision for emerging transmission customer interconnection projects. These amounts are aligned with the historical levels of spend and anticipated future activity. Deviations from these provisions, to respond to emerging interconnection needs, require an adjustment of the timing or scope of other projects and programs within the Capital Plan.

Distribution customer interconnection expenditures are more stable and are forecast based on historical levels.

The balance of the Growth portfolio is required to mitigate other system risks such as providing reliable service and/or allowing for the retirement of end-of-life assets. These Growth investments improve the reliability of the system or reduce the need for continued sustaining investments in assets that are at, or approaching, end-of-life. Examples include the construction of a new line to West Kelowna and a new substation in the West End of Vancouver to allow for the offloading of Dal Grauer substation. Even though these investments may be driven by the need to sustain the existing system, as is the case in the latter example, they are classified as Growth expenditures in the Capital Plan because they are adding new assets to the Power System.

2.4 Transmission and Distribution Bottom-Up Capital Planning Process

The following sections describe the steps of BC Hydro's bottom-up capital planning process for transmission and distribution assets.

2.4.1 Step 1 – Identify the System and Asset Needs

First, BC Hydro identifies system and asset needs to be considered for system reinforcement or remediation. This assessment includes reviews of system performance data to identify assets with degrading conditions, representing safety or environmental risks, not performing adequately or not meeting regulatory requirements. System and substation load forecasts are also developed to identify areas in the system that may require reinforcement. Based on these reviews, BC Hydro develops a preliminary approach and timeline for reinforcement or remediation.

The following information and data are used to assess system and asset needs:

- ***Asset Health and Performance:*** BC Hydro evaluates the condition of the Transmission and Distribution assets, based on the latest available maintenance test and inspection data, as well as engineering assessments and assigns an Asset Health Rating to each asset. The methodology provides assessments that are objective, repeatable, and consistent across asset classes. Assets with an index of Very Poor are generally considered for reinvestment within three years and assets with an index of Poor are generally considered for reinvestment within ten years. The Asset Health Index methodology and summary Asset Health Ratings for transmission and distribution assets is provided in Appendix M;
- ***Customer reliability:*** BC Hydro also reviews reliability statistics, identifies assets with poor performance and develops solutions for improvement. For example, distribution feeders are studied to determine the areas of under-performance, conduct root cause analysis and assess solutions for future investment to improve reliability;
- ***Regulatory Requirements:*** BC Hydro also evaluates the compliance of assets with the regulatory requirements of the *Workers Compensation Act*, B.C. *Wildfire Act, Canadian Environmental Protection Act* (e.g., *PCB Regulations*) and other environmental laws, as well as requirements of Mandatory Reliability Standards, Measurement Canada, and Transport Canada; compliance is addressed within the requirements of each regulation;
- ***Load and Energy Forecasts:*** BC Hydro assesses the capability of the transmission and distribution system to meet expected peak demand and accommodate forecast load and generation additions; and
- ***Other Risks:*** BC Hydro assesses the potential severity and likelihood for a range of risks including safety, seismic, environment, fire, extreme weather,

and security. High risks, as determined by BC Hydro's enterprise-wide framework for capital prioritization, are considered for remediation. The enterprise-wide framework is discussed further in section 1.4.

2.4.2 Step 2 – Determine the Scope of Strategies, Plans and Studies

Second, BC Hydro determines the scope of strategies, plans and studies to assess identified needs. Multiple needs, impacting the same parts of the system, within a similar timeframe are integrated in this step so that they can proceed through the planning process together.

In this step, identified needs are reviewed by regionally-focused cross-functional teams to determine integration opportunities. These teams consider how needs relate to each other as well as the required timelines for remediation and the risks of delay. These reviews may result in certain needs being addressed through province-wide work programs or deferred due to low risk.

Third-party interconnection requests are not typically considered for integration with other needs. These projects normally proceed individually through their respective mandated and schedule-driven processes.

2.4.3 Step 3 – Develop Strategies, Plans and Studies

Third, BC Hydro develops strategies, plans and studies to evaluate the identified needs in detail and to identify technically feasible alternatives to remediate these needs through projects or work programs. The completion of strategies plans and studies may vary from a few weeks to several years depending on the complexity of the needs and alternatives. Examples of these documents include:

- ***Area Plans:*** Area Plans are specialized technical planning studies to identify alternatives to address needs related to issues such as load growth, new generation and system reliability. The Downtown Vancouver Electric Supply

Plan and the Abbotsford Area Reinforcement Study are example of integrated Area Plans;

- ***Facility Asset Plans:*** Facility Asset Plans are developed for substations with multiple pieces of equipment that require replacement within a similar timeframe. The Barnard Substation Asset Plan is an example of a substation asset plan; and
- ***Asset Class Strategies:*** Asset Class Strategies determine the appropriate remediation approach for each asset class. Asset Class strategies include replacing the asset or continuing to perform maintenance on the existing asset.

Summaries of Area Plans, Facility Asset Plans and Asset Class Strategies are provided in Appendix K.

2.4.4 Step 4 – Annual Capital Planning Review

Fourth, as part of the annual capital planning process, BC Hydro undertakes a review of planned investments. Investments are reviewed by cross-functional teams to align investments across the portfolios. In addition, investments are reviewed to check that the data quality is sufficient and that the investments are appropriately prioritized and timed. These investments are then submitted into the Integrated Power System Portfolio Management process, as described in section 2.5 below.

2.5 Integrated Power System Portfolio Management Brings Planned and Ongoing Projects and Programs into One Portfolio

Once a year, forecasts for the planned generation, transmission and distribution projects and programs, developed through the bottom up processes described in the preceding sections, are brought together with projects and programs already being delivered. This consolidation of a single Power System capital investment portfolio begins the final stage of the preparation of the Power System Capital Plan.

The enterprise wide framework for capital prioritization, described in section 1.4, is used to categorize each investment in the initial portfolio, and assign risk to the deferral of the investments. Where labour resources have been identified as a risk to the delivery of the portfolio, the demands on the labour pool to deliver each investment are assessed and the availability of those resources are estimated.

The final step of the process is to review the Power System capital investment portfolio to determine the highest priority projects and programs within the labour and financial constraints that have been identified. These results are then reviewed with the leadership team of the Integrated Planning Business Group. This provides an opportunity for senior leaders to offer input and to align the portfolio business objectives. Once endorsed by the Integrated Planning leadership team, the Power System Capital Plan is submitted into the Enterprise Capital Planning process, which is described in section 1.4.

2.6 Planning and Delivery Processes Are Well Integrated

This section provides an overview of the collaboration and integration between planning and delivery through the annual capital planning process, work planning and the release of projects and programs to the KBUs responsible for delivery.

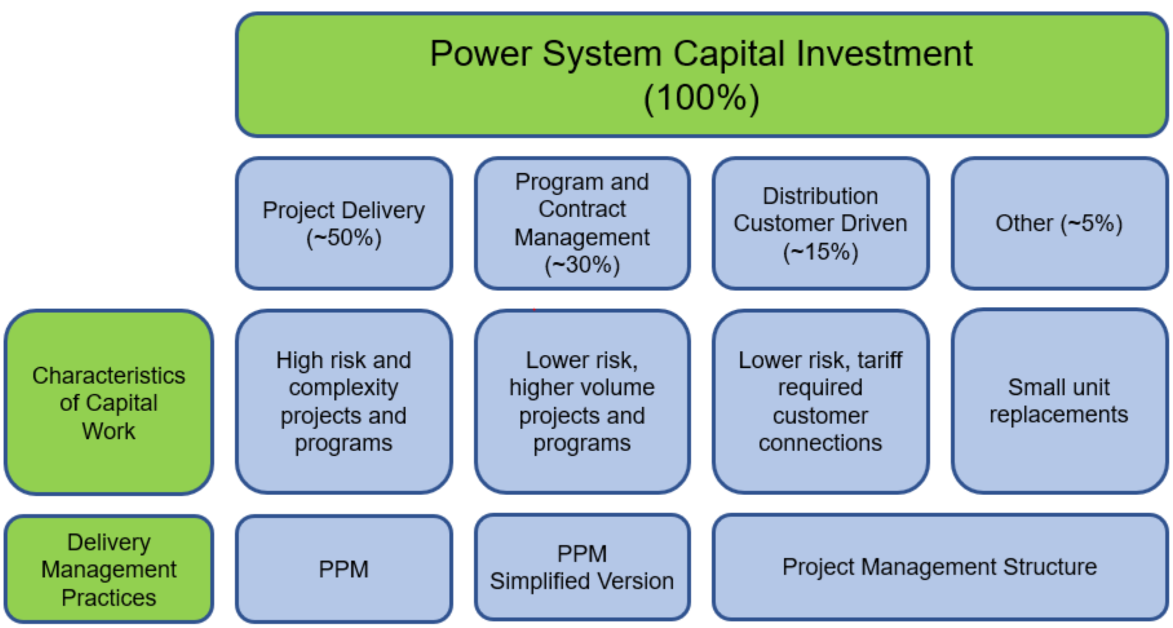
Investments associated with the Power System are delivered by three different KBUs: Project Delivery, Program and Contract Management, and Distribution

Design and Customer Connect. The processes followed by each KBU are adapted to suit the types of investment that they are responsible for delivering.

Large and complex investments generally require more rigorous delivery processes, involve a larger and broader group of internal and external stakeholders, and call for a high level of oversight and governance. Smaller projects or higher volume replacements of less complex assets require a scaled approach. Therefore, BC Hydro utilizes a range of delivery management practices to suit the range of investments that need to be delivered.

Figure N-3 below provides a summary of the Power Systems capital investments to be delivered by each KBU as well as the delivery management practice used to deliver those investments.

Figure N-3 Summary of Power Systems Capital Investments by Delivery KBU



2.6.1 Established Process Allows Early Identification of Issues and Resources

BC Hydro has an established process for early identification of issues and resources, so that work is assigned to the correct KBU with the appropriate delivery process for the nature of the investment and with resources to complete the work.

During the annual capital planning process to develop the Capital Plan for the Power System, the planning and delivery KBUs collaborate to:

- Consider labour resource availability, and validate that the Capital Plan for the Power System can be delivered with available internal and external resources;
- Determine the delivery model and assign capital investments to the appropriate KBU for delivery, considering factors such as:
  - Asset types and characteristics;
  - The size, scope, complexity, duration and costs of the projects or programs; and
  - The number of internal and external stakeholders that need to be involved.
- Review the larger and more complex projects that are proposed to be delivered by the Project Delivery KBU. This includes a review of the problem statement, possible alternatives, project scope, project duration, delivery risks and potential operational constraints.

2.6.2 Integrated Planning Remains Involved Throughout the Delivery Process

After the completion of the annual capital planning process, BC Hydro begins work planning. This involves reviews of specific investments targeted for release in the next fiscal year. The planning and delivery KBUs review the scope of planned capital investments in greater detail and consider the portfolio of planned work as well as investments already underway, to determine the appropriate time to start new work.

After work planning is complete, capital investments are prepared for release to the appropriate KBUs for delivery. This step includes final planning reviews and required financial approvals to initiate the work.

Capital investments to be delivered by the Project Delivery KBU are planned annually for release on a quarterly basis. This quarterly release plan is reviewed by the planning and delivery KBUs regularly to confirm that adequate resources are available prior to project release and may be updated in response to changing resource availability that may require the timing of work to be adjusted. Capital investments to be delivered by the Program and Contract Management KBU and the Distribution Design and Customer Connections KBU are typically released on an annual basis, prior to the start of the fiscal year. After planned capital investments have been released to the appropriate delivery group, the Integrated Planning Business Group continues to be involved throughout the delivery process and participates in key decisions and accountability meetings as the initiating group representatives.

2.7 Project Delivery KBU Uses the Project and Portfolio Management System to Deliver Larger, More Complex Projects

The Project Delivery KBU is responsible for delivering larger, more complex Power System projects. Approximately 50 per cent of the planned capital investments in the Power System are be delivered by the Project Delivery KBU.

A rigorous project delivery process is critical to delivering large or complex projects effectively. The Project Delivery KBU uses the Project and Portfolio Management System (**PPM**) system for consistent management of project risk, scope, schedule and cost.

2.7.1 Project and Portfolio Management System is Consistent with Industry Standards

PPM is BC Hydro's framework to manage engineering and construction projects that require engineering and/or project management services. It provides a consistent approach to minimize delivery risks. PPM practices are consistent with industry standards such as the Project Management Institute's Project Management Book of Knowledge and the Association for the Advancement of Cost Engineering International Recommended Practices. PPM is structured as a Quality Management System, consistent with the principles of ISO 9001, 2008 Quality Management Systems - Requirements.

There are three key components to the PPM system: practices, tools and learning. These components are described further in the sub-sections below.

2.7.2 PPM Practices Standardize the Management of Large, Complex Projects

All capital projects managed within PPM are delivered using a standard set of defined practices. BC Hydro's six defined Project Delivery Practices are:

- **Project Management** - The objective of this practice is to ensure efficiency and discipline in our work by providing a consistent framework for delivering projects and producing associated documentation. Application of these practices ensures safety for the public and employees, the quality of work delivered through the projects and our future capacity by sharing knowledge and lessons learned;
- **Design** – This practice aims to ensure efficiency and consistency in engineering design to provide facilities and equipment that are fit for purpose and will operate safely, reliably, economically and in an environmentally responsible manner, over the asset lifetime;

- **Construction and Contract Management** – This practice documents the services that we apply to construction projects, programs, and portfolios to achieve project objectives with regards to safety, security, environment, project scope, quality, schedule, cost, and Mandatory Reliability Standards;
- **Indigenous Relations** – This practice manages consultation and engagement with Indigenous Nations on BC Hydro's capital projects;
- **Procurement** – The objective of this practice is to ensure efficiency, consistency and quality in major capital project procurement by providing a framework for producing and delivering contracts that meets project requirements; and
- **BCUC Regulatory –** This practice is to provide regulatory advice to BC Hydro's business areas, and to facilitate the successful management of the company's business issues and initiatives through regulatory review processes that result in rates to BC Hydro customers that are fair, just and reasonable, and allow for the recovery of BC Hydro's revenue requirements.
- **Environment–** The objective of this practice is to strategically manage environmental risks in all life-cycle phases while ensuring regulatory compliance requirements are achieved and aligned with our Environmental Strategy and supporting BC Hydro's consent/license to operate.
- **Stakeholder Engagement -** The purpose of the Stakeholder Engagement Practice is to support the delivery of the communications, stakeholder engagement, issues management, media relations and government relations services to capital projects.
- **Properties** – The purpose of this practice is to support the delivery of Property related services to capital projects by developing and maintaining processes, tools, templates and guides to promote consistent and high quality Properties

deliverables to successfully achieve the scope, schedule, quality and cost objectives provided in the Project Statement of Objectives.

In addition to the nine Project Delivery Practices, PPM also includes Program Management and Portfolio Management Practices.

The specific objectives of the Program Management Practice are to:

- Integrate program management with other Project Delivery practices including portfolio management and project management;
- Provide a common approach to the management of programs within Project Delivery at BC Hydro;
- Support the planning and delivery of programs, including objectives, outcomes and benefits; and
- Support program managers with processes, techniques and templates.

The Portfolio Management Practice aims to establish consistent standards to support effective management of portfolios of project, program, and work program expenditures for Project Delivery projects. In particular, portfolio management guides the creation of a Portfolio Delivery Plan that describes the optimal approach to delivery of the entire portfolio, considering aggregation and coordination of opportunities and risk responses.

The Portfolio Management Practice also supports development of a baseline for measuring actual performance of the Portfolio Delivery Plan against the identified targets. This performance measurement allows management to understand and make more informed decisions on the interactions between projects, programs and work programs, to identify potential problems or opportunities, and to make timely interventions.

Underlying all of the Project, Program and Portfolio Practices are four “global” Practices:

- Document and Records Management – defines the framework in which documentation and records are required and dealt with for portfolio, program and project delivery;
- Performance Management – defines key performance indicators that are implemented to measure the project, including projects that are managed as part of a program;
- Reporting – provides background on reporting, its structure, the basics about the reporting process as well as what is required to develop quality reports; and
- Resource Management – ensures that resources are planned for and assigned to complete projects on schedule.

2.7.3 PPM Incorporates the Consistent Use of Technology in Project Management

BC Hydro’s PPM process uses technology solutions to manage project components. The following provides a high-level summary of these solutions and their application.

- There are two modules in the SAP system:
  - The Project Systems module provides a single system of record for work breakdown structures and financial data; and
  - The Business Warehouse module provides automated reporting on projects in the PPM process.
- The Primavera system has three components:
  - P6 software provides cost and schedule forecasts for each project;
  - Unifier is a contract management tool that is linked to the project schedules in Primavera P6; and

    - ▶ Primavera Risk Analysis performs schedule risk analysis on complex projects with a higher degree of risk.

- The PPM Workspace system (Microsoft SharePoint) provides document management functions.
- The PPM Information Centre is a web-based system that provides a record of the PPM practices.

2.7.4 PPM Includes a Learning Component to Support Best Practices

The Learning component of PPM involves the development of BC Hydro’s staff and the sharing of knowledge and experience. This is achieved through:

- **PPM Information Centre** – A website of learning and reference materials associated with Project and Portfolio Management;
- **Community of Practice** – Team sessions for all BC Hydro staff and contractors facilitated by internal and external subject matter experts;
- **Communication Hub** – an online newsletter that provides role-specific, directed communications of changes that affect how we deliver PPM projects;
- **Learning Plans** - including role-based learning available online for Document Coordinators, Schedulers and Work Package Managers to provide easy access to role specific training information;
- **Career Development site** – career pathways and progression models based on Project Delivery roles;
- **Training Sessions** – BC Hydro hosts regular Community of Practice Learning events as well the International Project Management day, where internal and external presenters share their knowledge of best practices, lessons learned and provide an opportunity to network with others; and

- **Industry Organizations** – BC Hydro participates in industry groups to share Project Management best practices, including the Project Management Institute West Coast Chapter, Western Energy Institute, Canadian Electric Utility Project Management Network and Utility Peer Group (consisting of North American utilities).

2.7.5 Project Delivery Lifecycle Involves Staged Refinement of Scope and Estimates and Gate Approvals

The delivery lifecycle of PPM projects is divided into four phases: Initiation, Identification, Definition and Implementation. Each phase is further divided into various stages. The lifecycle represents a staged approach to project definition and gate approvals.

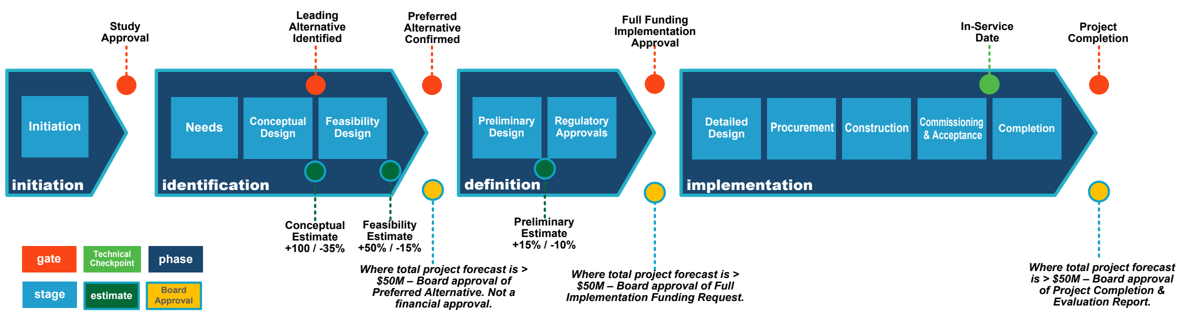
As projects move through this process, they become more defined. The increased level of definition allows for updated cost estimates to be developed. Cost estimates are provided at completion of the following stages:

- Conceptual Design: This estimate has an expected accuracy range of +100 per cent and -35 per cent;
- Feasibility Design: This estimate has an expected accuracy range of +50 per cent and -15 per cent; and
- Preliminary Design: This estimate has an expected accuracy range of +15 per cent and -10 per cent.

Gate approvals occur at defined points of the project lifecycle. Each gate is a formal approval point where key information on project cost, schedule, scope, procurement and risk is presented to the Gate Board. Further information on Gate approvals is provided in section 2.7.10 below.

Figure N-4 below provides a summary of the project delivery lifecycle. The Gates following each phase of the project lifecycle are shown as red circles, and approvals by the Board of Directors are shown in yellow circles. These project lifecycle phases and stages are non-discretionary.

Figure N-4 PPM Project Lifecycle



The following sections describe the four phases of the PPM Project Lifecycle: Initiation, Identification, Definition and Implementation.

2.7.6 Phase 1 in PPM Project Lifecycle: Initiation

The Initiation Phase begins by establishing an issue, risk or opportunity to be addressed through a planned capital project. A Study Approval Gate occurs at the end of the Initiation phase to conclude this phase and provide approval to proceed to the Needs and Conceptual Design Stages of the Identification Phase. This Gate represents the release of the project from Integrated Planning to Project Delivery. A Project Manager is then assigned to manage the specific project through to completion.

2.7.7 Phase 2 in PPM Project Lifecycle: Identification (+100/-35 per cent)

The Identification Phase consists of three stages: Needs, Conceptual Design and Feasibility Design.

- **The Needs Stage** clarifies and validates the risk, issue or opportunity to be addressed and develops a selection of high-level solution alternatives for further consideration. In this stage, an initial Work Breakdown structure, Statement of Objectives and Project Plan are developed. This includes the development of documents and systems to support the project delivery process throughout the lifecycle of the project;

- **The Conceptual Design Stage** analyzes the alternatives developed in the Needs stage and selects the alternatives to be carried forward into the Feasibility Design stage. For each selected alternative, an overall concept plan is developed including preliminary drawings of major project features, a general definition of equipment and system requirements and an overview of First Nations, stakeholder, environmental, socio-economic and procurement considerations. The selected alternatives are refined to eliminate the alternatives that do not meet the project objectives and to recommend a Leading Alternative that is technically and economically feasible and should be considered further. The main deliverable in the Conceptual Design stage is a business case which describes the alternatives considered, the methodology for evaluating those alternatives and the recommended Leading Alternative. The recommended Leading Alternative is confirmed through the Leading Alternative Identified Gate. Once this approval is provided, a conceptual design level estimate is prepared, with an expected accuracy range of +100 per cent and -35 per cent; and
- **The Feasibility Design Stage** conducts the investigations and analysis required to confirm that the Leading Alternative should be selected as the Preferred Alternative, to be carried forward to the Preliminary Design Stage of the Definition Phase. This analysis may include field and laboratory investigations as well as further evaluation of First Nations interests, environmental and other non-technical considerations. This analysis provides the required detail to prepare plans for the Definition Phase and to develop a feasibility design level estimate, with an expected accuracy range of +50 per cent and -15 per cent. At the end of the Feasibility Design stage, an

updated business case is developed and a Preferred Alternative Gate is held to confirm the Preferred Alternative. After the Gate, for projects with an Estimate at Completion greater than $50 million, the Executive Team reviews the Preferred Alternative before it proceeds to the Board of Directors for approval.

2.7.8 Phase 3 in PPM Project Lifecycle: Definition (+15/-10 per cent)

The Definition Phase defines the major project components in sufficient detail to develop a Preliminary Design cost estimate with an accuracy range of +15 per cent and -10 per cent. In this phase, implementation funding and any required regulatory authorizations are obtained. In addition, the Project Manager verifies that sufficient input has been received from First Nations via engagement and/or consultation as well as from internal and external stakeholders. To complete the Definition Phase, the Statement of Objectives, the Project Plan for the Implementation Phase and the final Business Case are examined through the Full Funding Approval Gate. Where required, projects greater than $100 million will be subject to a BCUC capital projects application. In those cases, an approval may be required prior to completing the Definition Phase. This Gate confirms that the risks associated with executing the work in the Implementation Phase are well managed and acceptable, before proceeding to that phase. After the Gate, for projects with an Estimate at Completion greater than $50 million, the Executive Team reviews the Full Funding Approval request before it proceeds to the Board of Directors for approval.

2.7.9 Phase 4 in PPM Project Lifecycle: Implementation

The Implementation Phase consists of five stages: Detailed Design, Procurement, Construction, Commissioning and Acceptance, and Completion.

- The Detailed Design stage is the final stage in the design process. This stage refines the Preferred Alternative so that it can be represented in a manner that allows work to be procured, manufactured and constructed in accordance with objectives, requirements, industry standards and accepted practices. Drawings and specifications are prepared in this stage and depending on the scale of the project, several design reviews may be required.

- The Procurement Stage initiates the sourcing process and issues tenders or requests for bids and proposal documents. In this stage, contracts are awarded for the supply, installation and construction of required work.
- The Construction Stage develops, manufactures, supplies, installs and constructs the required work in accordance with the contract specifications, drawings, and criteria.
- The Commissioning and Acceptance Stage tests and commissions the constructed facility or component in accordance with the prescribed criteria and applicable Mandatory Reliability Standards. Once the facility or component has been successfully commissioned, accepted and is fit for service, operational authority is transferred from the Project Delivery KBU to the appropriate KBU within the Operations Business Group.
- During the Project Completion Stage, the Project Delivery KBU provides a list of post-project commitments and conditions of permits, approvals and agreements to the responsible KBU within the Operations Business Group. The final deliverable in this stage is the project completion and evaluation report. Once this report is accepted, the project is classified as complete.

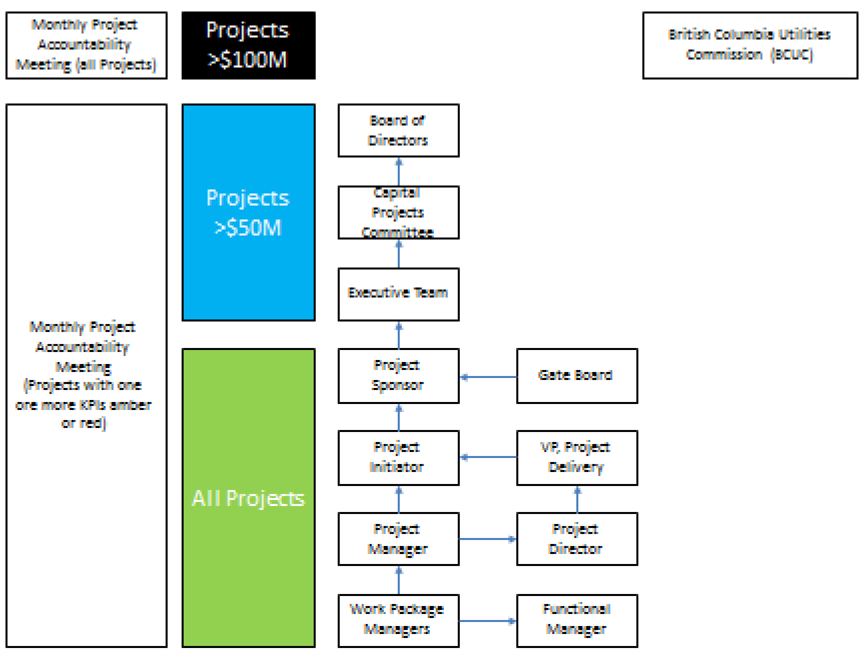
2.7.10 Project Delivery Roles and Responsibilities are Well Defined

Another important attribute of our project delivery process is that roles and responsibilities are well defined in advance. The process we employ streams projects based on their size and complexity, with additional levels of oversight for complex or higher risk projects.

BC Hydro deploys a matrix organization for resourcing and managing people assigned to capital investments delivered by the Project Delivery KBU. This means that staff are assigned to a project from various KBUs across the company to perform the required roles. Staff can be assigned to a project on a full-time or part-time basis and are accountable to the Project Manager for all project related work and decisions. The Project Manager is responsible for the day to day direction and decisions on the project. The KBUs that assign staff are responsible for setting standards, process and practices for their staff, conducting training on those practices and processes and for providing collegial support, approval of expenses and performance management.

Figure N-5 below illustrates the project governance structure for projects delivered by Project Delivery.

Figure N-5 Project Delivery KBU - Project Governance Structure



The following provides a summary of the various roles within this governance structure:

- ***Work Package Manager:*** The Work Package Manager is responsible and accountable for the planning and delivery of the Work Package within the approved scope, cost, and schedule as detailed in the Work Package Agreement. The Work Package Manager works with the Project manager and related Work Package Managers to create and develop the Work Package agreement (an element of the project scope);
- ***Functional Manager:*** The Functional Manager is responsible for the review of the Work Package agreement with the Work Package Manager to assess expectations for resource needs and review assumptions, scope, deliverables, milestones and activities related to the Work Package Agreement;
- ***Project Manager:*** The Project Manager is responsible for leading the project team to complete the objectives of the project. The Project Manager is accountable to the Project Initiator to determine the need, justification and objectives (scope, schedule and cost) of the project as well as to the Project Delivery Director for the delivery of the project against approved objectives and in accordance with approved policy and practice;
- ***Project Delivery Director:*** The Project Delivery Director is accountable to the Vice President of Project Delivery and is responsible for the execution of the projects in their portfolio against approved objectives and in accordance with approved policy and practice. The Project Delivery Directors chair the gate board meetings for projects with a cost of less than $10 million;
- ***Vice President, Project Delivery:*** The Vice President, Project Delivery is responsible for the delivery of the projects assigned to the Project Delivery KBU and is accountable to the Senior Vice President of Capital Infrastructure Project

Delivery. The Vice President, Project Delivery chairs the gate board meetings for projects with a cost of greater than $10 million;

- ***Project Initiator:*** The Project Initiator is the person with the authority to initiate work and is responsible for defining the work through the Statement of Objectives and justifying the work through the Business Case. The Project Initiator is also responsible for securing all required financial approvals. The Project Initiator sets project requirements which are then translated by the Project Manager into project scope, schedule and cost. The Project Initiator is accountable to the Project Sponsor for the definition and justification of the project; and
- ***Project Sponsor:*** The Project Sponsor supports the success of the project, by approving the project and liaising with senior management. At Gate board meetings, the Project Sponsor receives and considers Gate board recommendations to decide whether to approve key project decisions.

The following committees provide oversight of projects and endorsement of project funding requests:

- **Project Accountability Meetings:** BC Hydro conducts monthly Project Accountability Meetings to allow the Project Manager to update Gate Board members and internal stakeholders on the ongoing status of each project and provide a forum for participants to ask questions and deliver input and guidance. All projects with forecast capital costs greater than $80 million and projects under $80 million where one or more Project Key Performance Indicators are amber or red are reviewed monthly. The discussion at these meetings includes items such as project schedule, cost, scope, safety, operations, Indigenous relations, stakeholder engagement and project risks.

Table N-2 below identifies Project Accountability Meeting attendees.

Table N-2 Project Accountability Meeting Attendees

Senior Vice President, Integrated Planning	Senior Vice President, Capital Infrastructure Project Delivery
Director, Engineering Design	Executive Vice President, Operations
Director, Engineering Services	Vice President, Project Delivery (*Chair*)
Vice President, Asset Planning	Director, Indigenous Relations
Director, Stations Asset Planning	Director, Environment
Director, Dam Safety	Director, Properties
Director, Finance	Director, Stations Field Operations
Director, Interconnections	Senior Safety Advisor, Safety

- **Gate Board Meetings:** Depending on the stage of the capital project, the project's estimated cost, scope, alternatives assessment, and implementation plans are subject to endorsement by a review at a Gate Board Meeting, before a funding request is approved. The Gate Board reviews the project to determine if it is ready to progress to the next stage of its lifecycle. In addition to funding and stage progression approvals, these meetings provide an avenue for discussions with, and guidance from, key delivery partners on the status of projects and potential future issues.

  As shown in Table N-3 below, there are two types of Gate Board Meetings, depending on the cost of the capital project:

Table N-3 Types of Gate Board Meetings

Meeting Type	Capital Project Size
Major Gate Meeting	Projects ≥ \$10 million
Non- Major Gate Meeting	Projects < \$10 million

Table N-4 below identifies major and non-major Gate standing members. Additional participants may be invited when applicable.

Table N-4 Major and Non-Major Gate Board Standing Members

Major Gate Board Members	Non-Major Gate Board Members
VP of Project Delivery (Chair)	Project Director (*rotate chair between portfolios*)
SVP of CIPD	
EVP of Operations	
SVP of Integrated Planning	
VP of Asset Planning	
Directors of Engineering	Directors of Engineering
Director, Stations Asset Planning	Director, Stations Asset Planning
Director, Dam Safety	Director, Dam Safety
Director, Line Asset Planning	Director, Line Asset Planning
Director, Interconnections	Director, Interconnections
Director, Stations Field Operations	Director, Stations Field Operations
Director, Line Field Operations	Director, Line Field Operations
Senior Manager, Field Safety Assurance	Safety Manager
Director, Finance Capital Project Delivery	Finance
Director, Indigenous Relations	PMO Indigenous Relations
Director, Environment	Manager, Project Environmental Risk Management
Director of Properties	

The following additional governance roles are performed for all projects with a forecast cost greater than $50 million:

- ***Executive Team:*** The Executive Team reviews the project to determine if the project is the appropriate response to the identified risk, issue or opportunity. This review occurs at the end of the Identification Phase. The Executive Team also conducts a review at the end of the Definition Phase to determine whether the project is ready to proceed to the Implementation Phase, given the assessment of residual risks. This review supports the recommendation for approval to the Board of Directors;
- ***Capital Projects Committee:*** The Capital Projects Committee is one of the standing committees of BC Hydro's Board of Directors. This committee assists

the Board of Directors in fulfilling its obligations and oversight responsibilities related to the delivery of capital projects. Specifically, this includes, but is not limited to, dam safety, the execution of long-term capital plans and budgets, project oversight and relationships with First Nations. For capital projects with a forecast cost greater than $50 million, the Committee reviews the status of capital projects during the Identification and Definition phases, reviews and recommends the preferred alternative for approval by the Board of Directors, following the completion of the Identification Phase, and reviews and recommends financial approval by the Board of Directors, before the start of the Implementation Phase. When making its recommendations to the Board of Directors, the Capital Projects Committee reviews potential impacts to Aboriginal rights and title as well as planned mitigations and considers whether, in moving forward with a project, BC Hydro's consultations with First Nations uphold the honour of the Crown. The Capital Projects Committee meets quarterly in conjunction with the Board of Directors Meeting; and

- ***Board of Directors:*** BC Hydro's Board of Directors is appointed by and accountable to the B.C. Government. The Board of Directors is responsible for safeguarding BC Hydro's resources by approving annual operating and capital budgets as well as individual capital projects with a forecast cost greater than $50 million. For these projects, BC Hydro has established processes in place to facilitate Board of Directors review and approval of the preferred alternative, following the completion of the Identification Phase, and financial approval, prior to the start of the Implementation Phase. When considering approval, the Board of Directors reviews potential impacts to Indigenous peoples as well as planned mitigations and ensures that in moving forward with a project, the honour of the Crown is maintained.

In addition to the roles and responsibilities described above, the BCUC provides independent third-party review and approval of the need for projects greater than

$100 million or of significant public interest, unless a project has been exempted by government regulation. The BCUC also reviews the status of projects through quarterly or semi-annual progress reporting, and may undertake a prudency review of projects, once implementation is complete.

2.8 We Use a Simplified Framework for Routine Power System Investments

The Program and Contract Management KBU is responsible for delivering less complex and repetitive Power System capital investments on BC Hydro's power system. The KBU is the single point of contact for the annual delivery of the maintenance and small capital investment portfolio that is developed and optimized by the Integrated Planning Business Group.

When the annual maintenance and small capital investment portfolio is received from the Integrated Planning Business Group, the Program and Contract Management KBU develops annual program and project delivery plans in collaboration with the KBUs in the Integrated Planning and Capital Infrastructure Project Delivery Business Groups. This includes consideration of First Nations and environmental issues. Internal resource commitments to deliver the work are obtained from the Engineering, Distribution Design and Customer Connect, Line Field Operations, Stations Field Operations and Construction Services KBUs. Contracting plans are then developed to deliver the balance of the portfolio. Internal FTEs are used to deliver a significant volume of the small capital work, with external contractors being used to provide scalability due to fluctuations in demand.

The capital investments delivered by Program and Contract Management are typically “like for like” replacements of assets or system upgrades that are based on pre-defined design standards, developed by BC Hydro's Engineering KBU. Examples of capital investments delivered by the Program and Contract Management KBU include duct-bank construction, some end-of-life equipment replacement and overhead line relocations within an existing or public right-of-way. These investments are routine in nature, have a lower risk profile and require minimal, if any acquisition of property or rights of way. The standardized nature of these investments means that there are limited, if any alternatives to evaluate. Standard procedures are established to select the most feasible alternative when required.

These investments generally do not require specific equipment procurement and the required materials are typically inventoried by BC Hydro's Materials Management department. When specialized services, equipment or materials are required, standing blanket services contracts or master purchasing agreements are used. Work is completed through unit-based contracts with external contractors.

The Program and Contract Management KBU applies a simplified version of the PPM practices that is suited to the lower complexity of the projects it delivers. For program investments that involve standardized units of work, the Program and Contract Management KBU applies simplified work management processes.

2.9 We Use a Standardized Process for Routine Customer Driven Work

The Distribution Design and Customer Connections KBU is responsible for work related to customer requests for new or upgraded connections to BC Hydro's distribution system. This KBU provides technical design services and project management for customer driven new connections work, under 5 MW in size. More complex projects over 5 MW or over $2 million in cost are managed by the Program and Contract Management KBU, with the Distribution Design and Customer Connections KBU providing design services.

The Distribution Design and Customer Connections KBU designs to standards, with engineering support where required, and follows a project management structure that involves standardized work order packages, with environmental, archeological, safety and job planning processes and checklists. This simplified process enables project cycle times to align with customer requirements.

The Distribution Design and Customer Connections KBU issues approximately 11,000 work order packages in support of new customer connections and customer driven improvement work. These work orders require customer interactions, design work and project coordination. A dedicated Express Connections Contact Centre within this KBU issues 37,000 service orders per year. Express service orders are simple customer connections which do not require design work.

While the Distribution Design and Customer Connections KBU plans for customer connections at a system level, individual customer connection projects depend on actual customer requests. Therefore, these projects are driven by customer timelines and are not planned in detail. Program volumes and characteristics are forecast based on historical trends. The staffing model for the Distribution Design and Customer Connections KBU includes full time regular designers, full time temporary designers and external service providers to provide flexibility and to balance internal work program and customer program demands so that customer requests are prioritized for delivery to the agreed in-service dates.

2.10 Financial Approval Policies and Procedures Apply to All Capital Investments

BC Hydro has well established Management and Accounting Policies and Procedures **(MAPP)** and Financial Approval Authority Policy (**FAAP**) that set funding approvals required for capital investments through each phase of the project lifecycle. These approval requirements and processes have been developed to balance financial controls with operational efficiency, based on the nature and risk of the capital investments. The policies and procedures apply to all groups delivering BC Hydro’s capital investments.

2.10.1 Company-Wide Approval Policies Are Documented

The policies that govern capital investment approvals are primarily included in:

- Management and Accounting Policies and Procedures 1.2.3A (Expenditure Authorization Requirements Policy);
- Management and Accounting Policies and Procedures 1.2.3B (Expenditure Authorization Requirements Procedure); and
- Management and Accounting Policies and Procedures 1.2.1B.2 (Financial Approval Authority Procedure).

The required financial approval processes set out in these documents depend on the type of capital investment. Capital investments are categorized into the following four main categories for financial approval processes:

- Phased Capital Projects;
- Non-Phased Capital Projects;
- Recurring Capital Programs; and
- Expenditure Authorization Request Exempt Capital Investments.

The financial approval processes for each category are discussed further in the sections below.

2.10.2 Phased Capital Projects Require Phase-by-Phase Funding Approval

For capital projects which are delivered using PPM phases, funding approval is required prior to the commencement of work for that stage or phase. Typically, funding is approved only for the next stage or phase once the required work for the prior stage or phase has been completed. The financial approver level is dependent on the stage or phase as well as the funding amount being requested. For projects that meet the BCUC thresholds for a Certificate of Public Convenience and

Necessity (**CPCN**) and section 44 reviews, applications are generally submitted to the BCUC during the Definition Phase.

Table N-5 below provides information on the funding approval process for phased capital projects, delivered by the Project Delivery KBU and Technology.

Table N-5 Funding Approval Process for Phased Capital Projects (Project Delivery KBU)

Phase	Primary Budget	Estimate Accuracy Level	Funding Approval Documents	Project Approvers and Finance Review	Basis of Approval	FAAP Approver
Identification Phase (Needs Stage)	O&M (CPI)[3]	N/A	• Annual Release Plan from Capital Plan • Maximum request is generally $200,000	• Project Release Committee • No Finance Review	Amount requested	Manager, Portfolio Optimization and Management
Identification Phase (Conceptual Design Stage)	O&M (CPI)	End of Stage provides +100% / -35%	• Statement of Objective (SOO) • If over $2M, business case and Expenditure Authorization Request (EAR) Form also prepared	• Project Sponsor • Project Initiator • No Finance Review unless requested amount is more than $2M	Based on cumulative O&M amount requested	Chief Executive Officer (CEO): Up to $50M Others: 25% of FAAP Planning limit
Identification Phase (Feasibility Design Stage)	Capital	End of Stage provides +50% / -15%	• SOO • Business Case • EAR Form	• Gate Board • Project Sponsor • Project Initiator • Finance Review required	Based only on capital amounts requested going forward	CEO: Up to $50M Others: 25% of FAAP Planning limit

[3] CPI refers to Capital Project Investigation cost.

Phase	Primary Budget	Estimate Accuracy Level	Funding Approval Documents	Project Approvers and Finance Review	Basis of Approval	FAAP Approver
Definition Phase	Capital	End of Stage provides +15% / -10%	• SOO • Business Case • EAR Form	• Gate Board • Project Sponsor • Project Initiator • Finance Review required	Based on cumulative capital amount requested starting from Feasibility Design Stage	CEO: Up to $50M Others: 25% of FAAP Planning limit
Definition Phase with Partial Implementation Phase costs (not including construction)	Capital	End of Stage provides + 15% / - 10%	• SOO • Business Case • EAR Form	• Gate Board • Project Sponsor • Project Initiator • Finance Review required	Based on cumulative capital amount requested starting from Feasibility Design Stage	CEO: Up to $50M Others: 25% of FAAP Planning limit
Partial Implementation Phase costs including construction	Capital	N/A	• SOO • Business Case or CPCN if applicable • EAR Form	• Gate Board • Project Sponsor • Project Initiator • Finance Review required	Total Project Estimate	Ultimate FAAP approver for Total Project Estimate
Implementation Phase	Capital	N/A	• SOO • Business Case or CPCN if applicable • EAR Form	• Gate Board • Project Sponsor • Project Initiator • Finance Review required	Total Project Estimate	Ultimate FAAP approver for Total Project Estimate

Table N-6 below provides information on the general funding approval process for phased capital projects delivered by other KBUs.

Table N-6 Funding Approval Process for Phased Capital Projects (Projects Delivered by Other KBUs)

Phase	Primary Budget	Estimate Accuracy Levels	Approval Documents	Project Approvers and Finance Review	Basis of Approval	FAAP Approver
Identification	O&M	N/A or Various	• SOO or business case or equivalent • EAR form (Technology)	• Business group dependent • Finance Review dependent on amount requested and type of capital	Amount requested or based on Total Project Estimate (Technology)	CEO: Up to $50M Others: 25% of FAAP Planning limit
Definition	Capital	Various	• Business Case • EAR Form	• Business group dependent • Finance Review required	Cumulative amount being requested or based on Total Project Estimate (Technology)	CEO: Up to $50MOthers: 25% of FAAP Planning limit
Implementation	Capital	Various	• Business Case • EAR Form	• Business group dependent • Finance Review required	Total Project Estimate	Ultimate FAAP approver for Total Project Estimate

2.10.3 Non-Phased Capital Projects Require Business Case and Authorization

Non-Phased Capital Projects are capital investments that are not delivered using project phasing but are similar to a one-time capital investment. Examples include the purchase of new equipment or office furniture. For Non-Phased capital investments over $0.5 million, an approved business case and Expenditure Authorization Request (**EAR**) form are required prior to any capital spending. These authorization documents are approved based on the total investment amount, in accordance with BC Hydro's Financial Approval Authority Policy requirements.

2.10.4 Recurring Capital Programs are Approved Annually

Recurring Capital Programs are generally completed each year, on an ongoing basis. This work is generally lower risk, involving like-for-like unit replacements, such as the annual distribution wood pole replacement program. These investments are authorized at the beginning of each fiscal year using the Recurring Capital Annual Expenditure Authorization Form.

2.10.5 Approved Work Orders Are Required for Low Cost Recurring Capital Projects

Expenditure Authorization Request Exempt Capital Investments are recurring capital projects with a low cost and high volume. Examples include work activities to connect distribution customers, which are required under the Electric Tariff and less than $1 million in cost. These investments are operationally approved through BC Hydro's Work Order system. A business case is required for any recurring capital project with a forecast cost of more than $1 million.

2.11 Portfolio Risk Adjustment Overview

BC Hydro's Capital Plan is based on project cost and schedule forecasts available at the time the Plan is developed. Variances to the planned fiscal year capital expenditures and capital additions of projects occur due to changing circumstances throughout the project lifecycle. The Portfolio Risk Adjustment is used to account for project level uncertainties to provide a more realistic portfolio level forecast (for both capital expenditures and additions) for the test period.

BC Hydro has used a Portfolio Risk Adjustment as part of our Capital Plan development since 2018 to account for the uncertainty in the schedule and cost of projects. The accuracy of project level forecast capital additions increases with the level of analysis and information on project scope, schedule and cost. Therefore, the largest uncertainties are associated with projects that are in early stages of the project lifecycle as their scope, schedule and cost are not as well defined as projects that are in later stages.

The Portfolio Risk Adjustment amount is calculated using a Monte Carlo simulation. A probability distribution is determined, based on historical project delivery performance information. The calculated Portfolio Risk Adjustment amount represents the difference (by fiscal year) between the expected value of the simulated portfolio forecast and the sum of individual project forecasts in the baseline Capital Plan.

Any differences between the forecast and actual amortization of capital additions are captured in the Amortization of Capital Additions Regulatory Account. This means that the actual amount recovered from ratepayers is ultimately based on the actual capital additions.

3 Supporting Portfolios Planning & Delivery Processes

3.1 Technology Capital Investments

The Technology KBU is responsible for the planning, design, delivery and operation of BC Hydro’s Information Technology (**IT**) systems and several Operational Technology (**OT**) systems. IT assets or systems are tools for commercial decision making, planning, business process management, and resource allocation. OT assets (or systems) provide operational monitoring and/or control of assets in the electric network in real time (or near real time).

3.1.1 Technology Planning

This section outlines the planning processes in place to understand the issues, risks and opportunities associated with these assets, and to identify the recommended capital investments. It also outlines the delivery processes in place to deliver projects and programs on time, on budget and within scope.

The Technology planning and delivery processes are integrated both within Technology and across the organization. They generally follow the same processes as described for the power systems portfolio, including both top-down and bottom-up asset planning processes.

3.1.1.1 Ongoing Technology Investment is Organized by Driver into Three Categories

BC Hydro's forecast Technology capital investments are grouped into the following three categories:

- **Manage compliance and security**: This category includes investments that address regulatory requirements, periodic foundational cybersecurity improvements, cybersecurity hardware replacements and software license renewals, and growing cybersecurity threats;
- **Manage risk and sustain productivity**: This category includes investments that address asset failure risk and new investments to help manage operational and business risks and expand information technology services as needed; and
- **Enhance business capability**: This category includes investments for new or improved business capabilities.

Table N-7 below summarizes the key capital investment drivers within each investment category.

Table N-7 Technology Investment Drivers by Category

Category	Investment Driver
Manage Compliance and Security	Regulatory compliance risk Investment toward achieving MRS, WorkSafe BC, or other compliance outcomes.
	Cybersecurity risk Investment driven by cybersecurity threats, vulnerabilities and incidents.
Manage risk and sustain productivity	Asset risk Investment to address declining asset health (including supportability), which increases the likelihood of asset failures including outages, declining performance and loss of capacity. The risk to business systems, capabilities, production and services are considered in a business-as-usual environment.
	Sustainment of productivity Investment to maintain the efficiency of IT assets, asset systems and the downstream business functions that rely on them. This includes recurring capital work programs (excluding enhancements), and software license purchases.
Enhance Business Capability	Enhancement of capability Investment to enable new or enhance existing business capabilities, to expand capacity, or to manage operational, financial, and reputational risks.

3.1.1.2 Ongoing Technology Investment is Organized Through Portfolio Management

The Executive Team provides top-down funding guidance for the Technology portfolio. Within this guidance, the Technology KBU enables desired business outcomes by sustaining the availability and security of our existing assets and providing new asset implementations and improvements as needed.

The required investments start as a list of mandatory or committed investments, and additional investment needs are prioritized into consolidated capital investment plans.

These capital investment plans address business needs and opportunities through upgrades and end of life replacements based on asset useful life or asset risk, periodic software license renewals and true-ups, enhancements to avoid functional obsolescence, capacity increases, and implementations to support new business capabilities. Individual investments are subsequently defined as projects, recurring work programs, or capital purchases.

The Technology leadership team oversees the implementation of its Capital Plan through monthly capital committee meetings. These meetings review variances between forecasts and budgets, manage risk adjustments, reallocate capital as needed to meet new priorities and business requirements and control the release of projects to delivery. Any in-year investment requests are managed through funding re-allocations and the ex-plan process.

3.1.1.3 Larger Investments undergo a Technology Benefits Realization Process

Each technology project has a business case outlining expected benefits. BC Hydro has developed a benefits realization process so that benefits claimed in business cases can be tracked and realized.

The benefits realization process monitors capital investments over $2 million in the delivery phase and once in service to help ensure the achievement of expected results. Benefits are monitored periodically over the asset life cycle.

3.1.1.4 Portfolio Risk Adjustment Overview

A portfolio risk adjustment helps provide a more accurate portfolio level forecast for the Test Period by applying a portfolio level discount to the bottom-up forecast expenditures and additions in order to offset forecasting bias.[4]

The Portfolio Risk Adjustment is assessed monthly based on project complexity, current delivery phase, distribution of forecast expenditures, and uncertainties related to specific costs.

3.1.2 Technology Portfolio Delivery Uses a Standard Framework

The capital investment portfolio consists of projects, work programs and acquisitions. Investments require approved business cases and adhere to a Technology-specific delivery framework called Information Technology Delivery Standard Practices (**ITDSP**).

3.1.2.1 We Use a Standard Technology Project Delivery Framework that Requires Approvals at Each Phase

ITDSP is used to aid managers, service providers and project teams in delivering successful technology projects. This framework was adopted in 2004 and is updated annually. The framework aligns with PPM Practices, which are discussed further in section 2.7 above and has been adapted to better support the unique character of technology projects.

[4] Bottom-up capital investment forecasts generally reflect estimation bias. This bias is visible at the portfolio level where risks associated with resource constraints are most evident. The most common bias is schedule optimism where project schedules are underestimated due to incomplete recognition of uncertainties related to project planning and delivery. A second source of risk is uncertainty of specific costs.

ITDSP uses standard PPM phases with uniquely defined stages. Gate approval points are positioned at the end of project stages so that management can confirm that the proposed project solution remains in alignment with business drivers and is ready to progress to the next phase or stage. Each gate is a formal approval point, where key information is presented to the gate board, typically related to cost, schedule, scope, procurement, and risk.

The following sections provide a high-level summary of the key activities within the project lifecycle phases.

3.1.2.2 Initiation Phase

The primary objective of the Initiation phase is the prioritization of a specific capital investment and the decision to prepare a business case. To support the decision to initiate a project, the Project Initiator is responsible for assembling a brief description of the problem or opportunity, key business drivers and any associated risks and estimated funding needs.

A decision is made to form and proceed with a project based on the understanding of the problem or opportunity and the risk to the business, support by the Project Initiator, the funding requirement, and the potential funding source.

The key outcomes of the Initiation phase are an Identification phase business case, a detailed Identification phase project plan, and firm Identification phase costs as well as an initial estimate on the overall project cost.

The Initiation phase concludes when the Identification phase business case is approved.

3.1.2.3 Identification Phase

The Identification phase includes three stages:

- **Needs Assessment** – to confirm the scope and business requirements;

- **Conceptual Design** – to review alternative solutions and select the leading alternative; and
- **Feasibility Design** – to evaluate the feasibility of alternative solutions and recommended an alternative to be taken forward to the Definition phase.

The key outcomes of the Identification phase are: approved and prioritized business requirements; an assessment of alternative solutions including a recommended solution and confirmed feasibility of the recommended solution; completion of a Process Impact Assessment; a Definition phase business case; a detailed Definition phase project plan; a firm Definition phase cost; and a refined range estimate for the overall project cost.

The Identification phase concludes when a decision is made on whether to proceed to the Definition phase (the Preliminary Approval Gate).

3.1.2.4 Definition Phase

The Definition phase includes two stages: High Level Design/Blueprint; and Regulatory Approvals.[5]

The objective of the Definition Phase is to carry out a detailed investigation of the selected alternative, and to prepare a high-level design, project implementation plan and estimate of the Implementation phase funding, including an Implementation phase business case. This phase also includes securing all required regulatory approvals as well as any key defining agreements.

The key outputs of the Definition phase are process documents, a High-Level Design/Blueprint (documented in the Architecture Definition Document), an

[5] Based on BC Hydro's Capital Filing Guidelines, the threshold for regulatory approvals is an estimated overall budget equal to or greater than $20 million.

Implementation phase business case, an Implementation project plan, and a firm overall cost estimate range to complete the project.

The Definition phase concludes when a decision is made on whether to proceed to the Implementation Phase (the Full Funding Approval Gate).

3.1.2.5 Implementation Phase

The Implementation phase includes seven stages: Detailed Design; Build; Test; User Acceptance Testing Deploy/Cut-over; Stabilization; and Completion.

The objective of the Implementation phase is to complete the detailed design, build, test and commission the solution into service.

The key outputs of the Implementation phase are a working solution, confirmed through testing, that meets project objectives and is fully transitioned into operation, and a Project Completion Report measuring success against the approved business case.

The Go Live Approval Gate represents a decision on whether to proceed to the Deploy/Cut-over stage.

The project is considered complete once the Project Initiator and Project Sponsor have accepted the project results by signing the Project Completion and Evaluation Report.

3.1.2.6 Technology Work Programs and Licenses Are Subject to Workflow Approval Processes

A Work Program is a program of high-volume sustainment or enhancements items, typically with a low cost per item, which utilizes simple workflows on highly standardized and repeatable work units to deliver an overall benefit. Work Programs are typically set up for one fiscal year at a time, for a specific asset or group of assets. As this work is less complex, the ITDSP framework and project life cycle do not apply. Similarly, capital purchases for licences and equipment are also not subject to the ITDSP framework as they are not projects.

3.1.2.7 We Optimize Internal and External Resources

Technology employs two primary delivery models to optimize the use of internal and external market-based delivery capacity:

- Projects are primarily delivered through managed teams, where BC Hydro staff or consultant project managers manage blended teams of employees, vendors and individual contractors; and
- For larger, more complex projects, BC Hydro uses an outsourced model, called the system integrator model, where teams of external service providers provide project delivery and a large number of developer resources are applied to a project.

This resourcing model is appropriate to deliver the Capital Plan in the Test Period. The use of blended teams and system integrators allows for rapid scaling of our workforce, as required.

3.1.2.8 Technology Project Delivery Governance

Governance of technology capital delivery is provided by project steering committees, project gate reviews and funding approval, the Executive Team and the Board of Directors.

- Project steering committees provide senior management level direction to projects to assist with resolving complex issues.
- Project gate reviews occur at various points of the project lifecycle. Each gate is a formal approval point where key information on project cost, schedule, scope, procurement and risk is presented to the gate board.
- The Executive Vice President approves projects greater than $6 million.

- The Board of Directors approves projects greater than $20 million.

Governance is also provided through BC Hydro's Management and Accounting Policies, which are discussed in section 2.10.

3.2 Properties Capital Investments

3.2.1 Properties Bottom – Up Asset Capital Planning Process

The Properties planning process follows a three-step bottom-up approach.

Step 1 – Identify the Asset Needs

The first step of this process is to identify the building and asset needs at each of the facilities that should be considered for remediation. This assessment includes reviews of existing asset issues and risks as well as asset condition assessments. This results in a list of proposed projects.

Step 2 – Formation of a Draft Capital Plan

The proposed projects are categorized, ranked by priority and then subjected to any funding constraints, in order to develop a draft capital plan.

Step 3 – Review the Investments in the Capital Plan Period

The draft plan then undergoes a series of reviews of the planned investments across the building portfolio to ensure that investments are appropriately prioritized and timed. This review also allows for validation of the operational requirements by Properties and BC Hydro operations and other KBUs. These reviews may result in a re-assessment of specific projects or shifting of projects within or beyond the capital plan period.

Properties proposed capital investments are subject to the BC Hydro enterprise-wide framework used to assist in prioritizing capital investment. Investments included in the BC Hydro 10-Year Capital Forecast are selected based on their prioritization score and other constraints, following the BC Hydro enterprise-wide process.

3.2.2 Properties Capital Investment Delivery Aligns with BC Hydro's Standard Approach

The delivery of Properties' capital projects are managed using both internal and external (contracted) resources following normal building construction industry practices. Properties' Capital Delivery processes align with the standard BC Hydro project lifecycle for managing projects, whereby:

- Projects progress through the four phases of delivery: Initiation, Identification, Definition, and Implementation; and
- Gate approvals are formal approval points positioned at the end of key stages in the project lifecycle to allow management to confirm that the proposed project solution remains in alignment with business drivers and that the project is delivering on key project objectives including cost, schedule, and scope.

3.3 Fleet Capital Investments

Fleet Services Asset Planning identifies and ranks vehicles and equipment for replacement using asset information (asset age/remaining life, mileage, maintenance costs, utilization rates, observed downtime frequency), input from fleet maintenance staff and end-users on asset condition, criticality and operational requirements. End-users also can identify requirements for upgraded or additional fleet assets. This information is used to assemble a list of vehicles and equipment for acquisition planning. The process is initiated in advance of the expected end-of-life replacement criteria (i.e., for a vehicle with a ten-year life replacement planning is started at approximately the seven-year mark). The general fleet replacement criteria are established based on historical data, as well as the suggested useful life in a commercial application as determined by BC Hydro fleet data, industry benchmarks and vehicle manufacturers. In addition, the work application and the environmental conditions in which the assets are operated are considered as they have an impact on the actual life of the vehicle.

Through the application of the enterprise-wide framework for capital prioritization, top-down planning and expenditure guidelines and other constraints, the list of vehicles for replacement, upgrades and vehicle additions are prioritized. Recommended acquisition plans are then vetted through senior management.

BC Hydro
Power smart

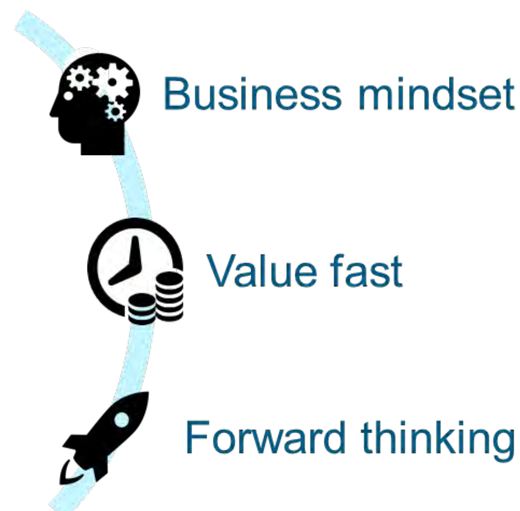
BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix O

Fiscal 2022 BC Hydro Technology Strategy and 5-Year Plan

BC Hydro
Technology Strategy and 5-Year Plan

Supporting BC Hydro's Service Plan Objectives



Prepared by the Technology Group

Updated September 2020

BC Hydro
Power smart

New in Fiscal Year 2021

Technology Strategy

Business mindset

Value fast

Forward thinking

Our strategy is to support BC Hydro in meeting its Service Plan objectives by optimizing our investments, delivering outcomes early and often, and leveraging future technology.

Over the past year we have made significant progress against the 5-Year Plan as well as in implementing the principles of the strategy. Our focus last year was on “making it easier to get work done” and using our principle of “delivering outcomes early and often” to rapidly make a difference for our front-line workers. We achieved this through mobile app development, deployment of robotic process automation and the introduction of rapid, iterative delivery methods where appropriate.

Two important areas of focus have emerged that require us to bring forward some elements of the plan. The first is the need to adapt to the COVID-19 pandemic and working from home. The second is the need to improve compliance outcomes related to Mandatory Reliability Standards (MRS) and NERC Critical Infrastructure Protection (CIP).

This year we are developing a compliance technology roadmap to identify areas for short and long- term improvements to our systems in support of compliance outcomes as well as advancing the deployment of collaboration tools such as WebEx for virtual meetings, training and events and Microsoft Teams.

To put our strategy into action, we continue to prioritize our investment. Our first priority is to ensure sufficient investment in cybersecurity and compliance, our second is to sustain our existing assets and capabilities, and our third is to support new business functionality. The majority of our capital funding is invested in sustainment. One of the largest sustainment investments we will make over the next 5 years is to move our SAP core systems onto the next generation SAP platform and database.

The 2020 BC Hydro 5-year strategy identifies digitizing work management as an objective for achieving cost effectiveness. Pre-initiation work on enterprise asset and work management is underway to determine our approach to achieving this objective.

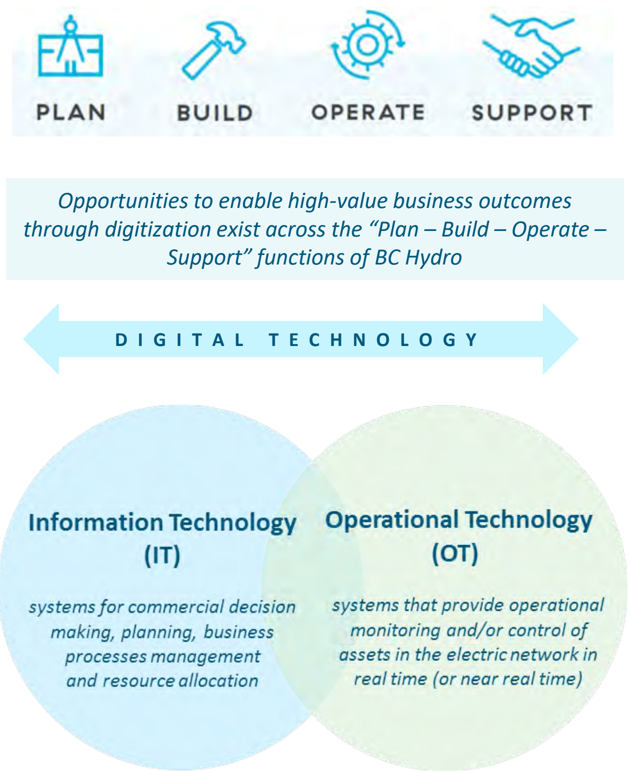
BC Hydro
Power smart

Introduction

Technology plays a critical role in the operation of BC Hydro and is embedded in virtually everything we do; from enterprise business systems, to the monitoring and controlling of field assets, to mobile devices in the hands of workers. Global trends, business competition, and high consumer expectations are driving rapid advances in technology. In the utility industry, the application of digital technology is viewed as essential in meeting future business objectives.

For BC Hydro, investment in technology can help us achieve our service plan objectives to provide reliable and responsive service, maintain affordable rates, continue to support clean, renewable energy and focus on safety above all else.

In this document, “technology” refers to digital technologies encompassing *information technology* (IT) as well as *operational technology* (OT). Traditionally separate domains in the electric utility business, the digital technology environments of IT and OT are now converging as the trend continues towards automation of all aspects of the power systems and the use of grid system data for business decision-making. New capabilities using rapidly evolving digital technologies such as cloud computing, mobility, internet of things, and machine learning, are being implemented as utilities modernize towards a more intelligent grid – this is the digitization of the utility industry.



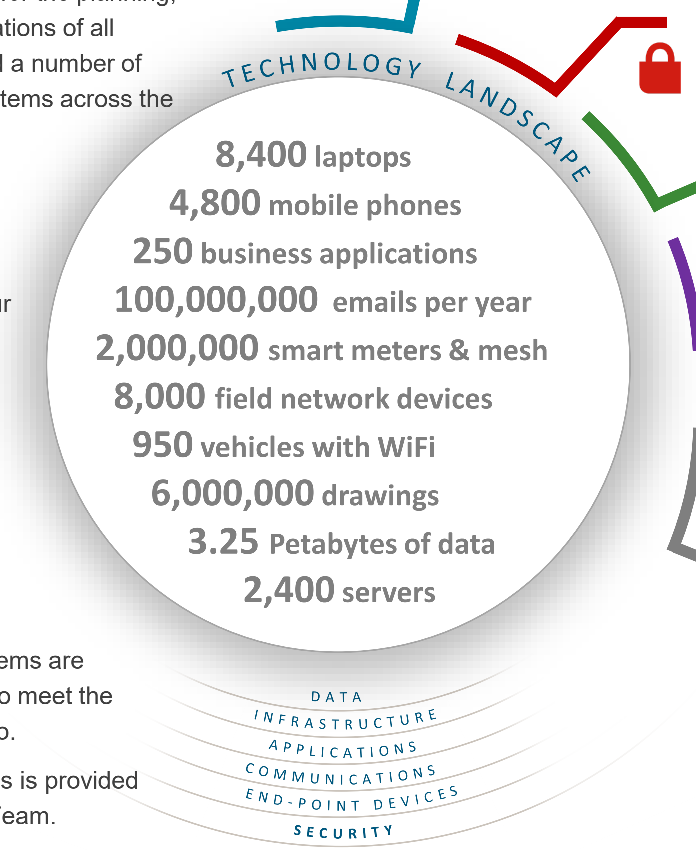
Introduction
Our role

Technology is responsible for the planning, design, delivery, and operations of all information technology and a number of operational technology systems across the enterprise.

We provide technology leadership and oversight across BC Hydro. We actively collaborate with our organization to understand current and future needs. We are responsible for the enterprise technology architecture, and selection of appropriate technology solutions to deliver strong business outcomes.

Our work ensures our systems are reliable, secure, and able to meet the growing needs of BC Hydro.

Governance of our activities is provided by BC Hydro's Executive Team.



Planning and operating our complex environment

Technology investment planning, architecture and design, performance management, data and information governance, portfolio and resource management, service management, service desk, systems monitoring, maintenance and support, incident response and recovery

Protecting our systems and information

System-wide cybersecurity, system design, monitoring and response, testing, education, policy, compliance, detection and protection tools, vulnerability assessment, securing perimeters, privacy protection, security risk management, records management, information protection, drawings management, library and archive services

Ensuring the resilience of our systems

Service continuity planning and response, disaster recovery, risk management, high-availability architecture, cloud-based services, internal capabilities for critical functions, asset maintenance and health management

Enabling new business capabilities

Engaging with the business to understand their current and future needs, managing our capital investments and on-going sustainment, delivering high value projects on-time, on-scope and on-budget

Improving operational efficiency

Effectively managing vendors and contracts, retiring legacy assets, balancing internal and external resources, modernizing tools and processes, introducing agile methods, use of cloud, out-of-the-box solutions

BC Hydro
Power smart

Introduction

About this document

This Technology Strategy and 5-Year Plan is the result of extensive collaboration across BC Hydro. Its primary goal is to provide guidance and direction for future technology investments to meet compliance and security objectives, sustain and modernize our existing operations, and enable new business capabilities.

Our strategy is to support BC Hydro in meeting its service plan objectives by optimizing our investments, delivering outcomes early and often, and leveraging future technology.

A clear strategy and plan is essential to inform the direction of future investments, but the approach looking forward must be flexible in order to adapt to, and exploit, the ever-changing technology landscape as well as to address new business opportunities as they arise. Given the rapid advancements in technology, and the continuing evolution of BC Hydro's business needs, the 5-Year Plan will be refreshed annually.

Our investment in technology is aligned with our capital plan over the next five years. The 5-Year plan describes the major investments we anticipate, however each will be supported by its own business case and initiated based on changing priorities, available funds and resources.

The purpose of this document is to:

- ✓ **Articulate BC Hydro's technology investment objectives**
- ✓ **Describe our strategy to meet these objectives**
- ✓ **Communicate the 5-Year Plan to guide investment and inform current and future regulatory submissions**

Context

- Our strategic objective
- Drivers for our strategy
- Digital value streams for electric utilities

BC Hydro
Power smart

Technology Strategy

Our strategic objective

This Technology Strategy and 5-Year Plan is designed to support BC Hydro in achieving its Service Plan Objectives:

- ✓ **Safety above all**
- ✓ **Set the standard for reliable and responsive service**
- ✓ **Help keep electricity bills affordable for our customers**
- ✓ **Help make renewable, clean power British Columbia's leading energy source**

Implementation of technology solutions has the potential to advance each of these objectives, for example:

- By maintaining the health, stability and security of our digital systems we assist in ensuring the reliability and responsiveness of our service.
- Providing tools to streamline workflows, optimize work and asset management, and inform decision making all enable productivity improvements that lead to affordable rates.
- Mobile applications can provide location and job specific information to assist with improving safety outcomes for field workers.

Technology Strategy

Drivers for our strategy

BC Hydro is affected by numerous drivers having a direct impact on the strategy we employ to meet our objective. These drivers affect the type of investments we make, how we prioritize investments and adapt to future trends.

Technology Strategy

BC HYDRO SERVICE PLAN OBJECTIVES

- Safety above all
- Set the standard for reliable and responsive service
- Help keep electricity bills affordable for our customers
- Help make renewable, clean power British Columbia's leading energy source

GOVERNMENT DIRECTION, REGULATION, AND COMPLIANCE

- BCUC regulation and rates forecast
- Mandatory Reliability Standards (MRS) and NERC CIP (Critical Infrastructure Protection) regulations requirements are increasing

BC HYDRO BUSINESS UNIT OUTCOMES

- Integrated Planning – optimize investments
- Capital Infrastructure Project Delivery – reduce delivery, safety and environment risk
- Operations – improve work management, productivity and maintain reliability
- Safety – improve safety outcomes, reduce risk
- Business Support Services – improve productivity and service
- Enterprise – Agile delivery, adapt to flexible work conditions

UTILITY INDUSTRY DIRECTION

- Security and compliance continues to be a rapidly increasing and growing market, ever changing and demanding
- Increased expectations for digital solutions to improve safety, productivity, and management visibility
- Increasing OT/IT convergence provides opportunities for knowledge and resource sharing
- A growing need to control distributed and customer side sources of energy as well as demand side management and load control
- Increasing electrification of transportation and management of charging infrastructure
- Climate change adaptation and mitigation

TECHNOLOGY ASSET HEALTH

- Existing systems are on ageing platforms that cannot be supported or are incompatible with newer operating systems
- Built in product obsolescence leads to regular upgrades to retain product support

TECHNOLOGY MARKET DIRECTION

- Subscription licensing is a major trend within the software industry changing our cost profile away from capital investment and towards operating costs
- Commoditization of technology services can result in lower costs, for example data network transport costs
- Everything as a service or cloud services are becoming the norm, changing our cost profile away from capital investment and towards increased operating costs

TECHNOLOGY TRENDS

- Cloud services are growing rapidly offering scalability, disaster recovery, and mobility enablement
- Mobility offers productivity benefits for field workers and a flexible COVID-19 response.
- Internet of things, Edge computing and Digital twin offers opportunities in asset monitoring and performance management
- Artificial intelligence and robotic process automation offer efficiency gains through replacement of manual processes
- Augmented and virtual reality for training, virtual mentoring, inspections and maintenance support
- Robotics and drones for inspections and progress reporting
- Blockchain for secure transaction processing

Technology strategy

Digital value streams for electric utilities

Digital technologies are used to enable new and improved capabilities and drive value across all functions of the utility.

PLANNING & DESIGN

High performance computing, cloud solutions, and advanced analytic and drafting tools enable more comprehensive and timely energy and system planning, load forecasting, resource management, engineering and design.

ASSET MANAGEMENT

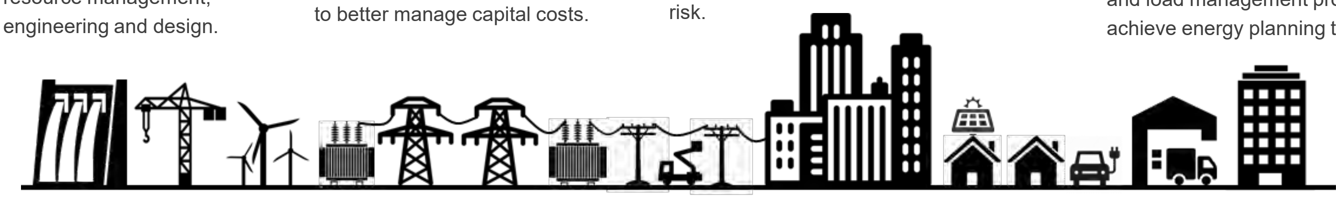
Real-time asset health information enables condition-based maintenance and just-in-time replacement to reduce asset sustainment costs. Asset health also provides for optimized investment planning to better manage capital costs.

MOBILE WORKFORCE

A fully mobile workforce seamlessly completes their field work. Job information is available, inspections are captured, drawings updated, and problems and progress automatically reported. Safety training and support is available on demand. Value is achieved through productivity, efficiency and reduced safety risk.

CUSTOMER ENGAGEMENT

Multi-channel technologies and relationship management tools improve quality and timeliness of customer interactions. Self-service reduces our costs and improves customer experience. Systems to support demand side management and load management programs help achieve energy planning targets.



WORK MANAGEMENT

Productivity, efficiency and risk reduction can be achieved through mobile applications, digital workflows to manage information and record keeping, use of drones to capture progress images, access to real-time data and business intelligence and analytics. Scheduling tools and optimization algorithms make managing work, during both normal and emergency situations, more efficient.

GRID INTELLIGENCE & CONTROL

Smart devices on the grid help optimize power delivery and resilience, and give operators and field service crews visibility into outages, faults, power quality issues, and the status of energized equipment. Digital systems manage distributed energy resources, automate connect and disconnect functions, power distribution and power quality.

SAFETY & SECURITY

Sensors, imaging and internet of things technologies provide visibility to facilities that are remote and/or unmanned. Monitoring and surveillance technologies improve identification and response to safety and security situations. Mobile field tools aid in worker and crew safety. Improved protection of digital information, systems and equipment reduces cyber security risk.

BUSINESS OPERATIONS

All business functions benefit from improvements to work processes, access to analytics, decision making, information management, and knowledge retention tools. Opportunities also exist to improve hiring, development and retention of valuable employees through specialized tools.

BC Hydro
Power smart

Our Strategy

- Principles
- Critical success factors

BC Hydro
Power smart

Technology Strategy

Our Strategy

We will adopt a business mindset, ensuring we work within our constraints to achieve the best outcomes for BC Hydro while maintaining the security and integrity of our information and systems at all times. We will adapt our solutions and processes to exploit short term opportunities and deliver outcomes early and often. We will develop technology roadmaps to ensure alignment on business solutions, leverage new technologies and prepare for technology obsolescence.

Business mindset

Optimize our investment

- ✓ Use a prioritization and selection methodology to achieve optimal outcomes
- ✓ Develop a plan that works within the constraints of costs and resources
- ✓ Use structured decision making in choosing investment alternatives
- ✓ Leverage existing systems
- ✓ Use a risk based approach to sustainment

Value fast

Deliver outcomes early and often

- ✓ Adapt delivery processes to deliver early and often
- ✓ Use a flexible architecture to support early value
- ✓ Leverage our existing systems
- ✓ Use off-the-shelf products
- ✓ Use cloud services

Forward thinking

Leverage technology

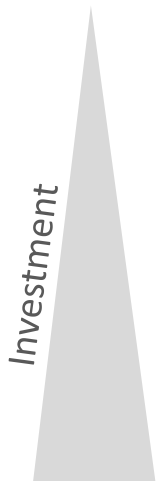
- ✓ Develop roadmaps for foundation technologies
- ✓ Ensure alignment of short-term business solutions
- ✓ Plan for future obsolescence

BC Hydro
Power smart

Technology Strategy

Principles – Business mindset

- **Justify and prioritize investments.** Investment proposals are selected into the portfolio based on relative value to the organization. Compliance, security, sustainment and risk mitigation solutions receive higher priority followed by those required to enhance business capability. Business cases must identify value and articulate specific benefits. Value (both cashable and non-cashable) from the investment must support the total cost of the investment.



Initiative / Investment	Description
Enhance our Capability	Discretionary activities that provide new or improved business capabilities
Manage our Risk and Sustain Productivity	Critical activities needed to ensure reliable and safe operations and to maintain the current level of productivity for our users
Compliance & Security	Mandatory activities needed to meet government/BCUC/NERC/WECC requirements

- **Work within our constraints.** Investment decisions are subject to the application of constraints due to funding, resource capacity, available skill sets, and ability of the organization to sustain and absorb change. Choices between investment options are decided through structured decision making.

- **Track the outcomes of investments**. Sponsors of technology-enabled initiatives are required to track benefits throughout implementation and into sustainment.

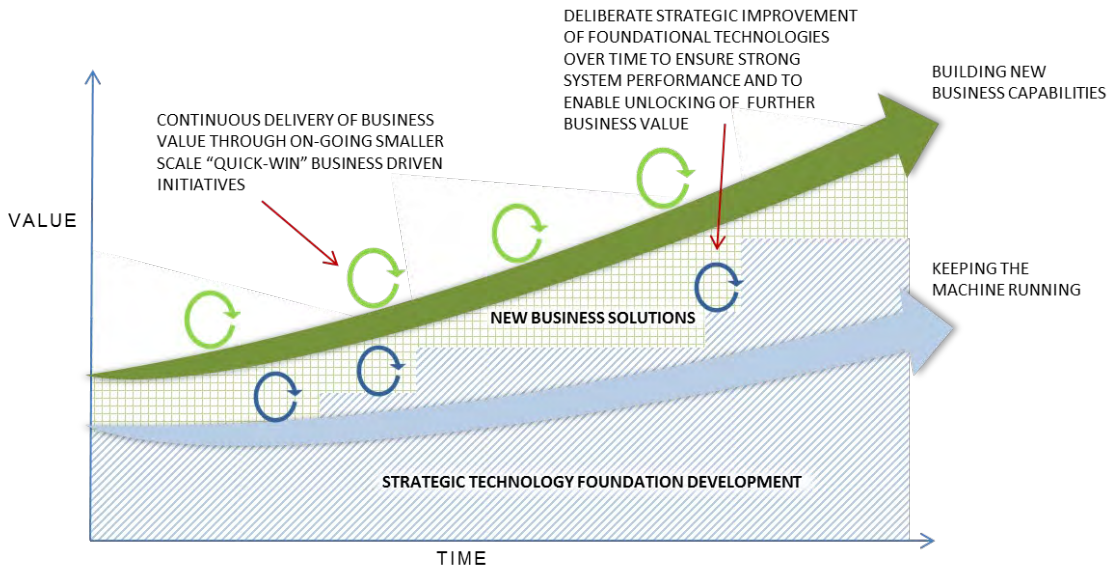
BC Hydro
Power smart

Technology Strategy

Principles – Value fast

- **Deliver value early and often.** Our approach is to exploit opportunities to deliver value early from interim solutions, even at a cost – provided the value exceeds the cost over the life of the interim solution. We will use "two-speed" or "agile" delivery methods, where appropriate, to expedite implementation of solutions.

- **Ensure architectural flexibility.** We will make investments that advance our delivery of value while still maintaining flexibility in our systems architecture. This allows for incremental and early value delivery, while implementing efficient and sustainable long-term foundation investments.



The diagram shows how we strive to deliver value early and often through incremental improvements (in green) while continuing to invest in our technology foundation for long term strategic business enablement (in blue)

BC Hydro Power smart

Technology Strategy

Principles – Forward thinking

- **Build for the future.** Technology roadmaps describe how we can invest in our foundation and leverage new technologies to enable our strategic objectives. The roadmaps sequence initiatives, identify decision points, and provide unconstrained scheduling of milestones to enable business outcomes. Given the dynamic nature of technology and technology industry changes as well as changes to BC Hydro's environment, our roadmaps will be updated regularly. The following summaries describe current guidance for each foundation area however all initiative proposals require individual investment justification.

NETWORK CONNECTIVITY	Sustain existing wide area, field area and local area networks, as well as extend network bandwidth and coverage to our more remote sites. Continue to refresh our network equipment based on end-of-life cadence, meet current and future capacity requirements, and take advantage of software alternatives as they become available. Continue to invest in wireless networks for our facilities and vehicles to enable workforce mobility, asset management, and increased safety and security.
ENTERPRISE APPLICATIONS	Continue to upgrade our enterprise applications based on a cadence to maintain product support. As upgrades are scheduled, take advantage of opportunities to modernize current platforms as per industry direction to remain current and reduce risk of obsolescence. Implement new customer contact centre systems to replace those that are not meeting requirements of availability and reliability, as well as modernizing the stack to extend and enhance current functionality for our customers. For Enterprise Resource Planning (ERP), we have adopted a "Core ERP" approach in which SAP is our single system of record for enterprise data but the systems our users engage with may be "bolt-ons" or cloud service products. Complete SAP Supply Chain and initiate Enterprise Asset Management and Work Management allowing for improved work planning and scheduling as well as the decommissioning of Passport. Migrate SAP to the S4/HANA© platform to maintain currency and support. Use Robotic Process Automation (RPA) to replace manual, repetitive processes on a case-by-case basis.
CLOUD & DATA CENTRE	BC Hydro's approach to cloud is to adopt services on a case-by-case basis. Use cloud services as needed for compute power, specific business functionality, disaster response environment, collaboration and productivity. Continue to refresh our data centre servers, storage and other equipment based on end-of-life cadence. As equipment is replaced, leverage opportunities to consolidate racks as well as review cloud options. Leverage major product upgrades in line with the direction our product vendors as they move to cloud platforms.

Technology Strategy

Principles – Forward thinking

MOBILITY SERVICES	Extend and improve our mobile services and mobile workforce capabilities. Continue to refresh our user's mobile phones and devices based on recommended refresh cadence, break/fix and device management requirements. Complete replacement of our existing mobile application management platform to better support device management, performance and required functionality. To facilitate future development of field worker applications, implement a suite of container services, application program interfaces (APIs) and a mobile work management platform. Strive to extend our device management capability to a broader range of devices.
GIS	Our approach is to use the ESRI platform for new applications requiring GIS (Geographic Information System), upgrade the current version of Smallworld and defer future direction decisions on our Smallworld GIS applications until the next major product replacement or upgrade. This will likely be the replacement of our Distribution Analysis & Design (DAD) and Spatial Asset Management (SAM) tools. Continue to focus on integrating GIS with our CAD (Computer Aided Design) tools, mobile application and ERP capabilities in order to support designers, field workers, asset management and work management. Extend our use of GIS in application development to provide geographic location search to access information, provide operational and emergency situational awareness. Continue to upgrade our GIS platforms based on a cadence to maintain product support.
PERSONAL WORKSPACE	Continue to refresh personal computing devices based on recommended refresh cadence, productivity, break/fix and device management. Upgrade our desktop environment to Windows 10 to improve performance and functionality, implement Microsoft's Office 365 suite of tools to support improved collaboration and productivity, and migrate to Microsoft Exchange Online to optimize storage capacity, ensure product support and align with product vendor direction. Upgrade our information collaboration (SharePoint) platform and make SharePoint online available for collaboration in the future. We expect to maintain an "on premise" presence for security and business continuity.

BC Hydro
Power smart

Technology Strategy

Principles – Forward thinking

CYBER SECURITY	BC Hydro uses a risk-based approach to cyber security and information protection. New investments are made based on compliance requirements, emerging threats and retaining our risk posture. Comply with NERC (North American Electric Reliability Corporation) CIP (Critical Infrastructure Protection) standards. Respond to audit reports, assess risk and ensure security of grid and facilities. Sustain and maintain our information management systems, corporate monitoring tools, firewalls and other protection equipment based on end-of-life cadence, and risk mitigation. Leverage upgrades to modernize our architecture and optimize network segmentation through software as it becomes operationally mature. Apply information technology (IT) cybersecurity best practices to our operational technology (OT) environments and develop an information protection program to improve security of our systems of record, information sharing and records management platforms.
BUSINESS INTELLIGENCE & ANALYTICS	BC Hydro's direction is to adopt a self-service model for analytics in which users are given access to data and can use their own tools and analysts to meet their needs. In support of this approach, work to broaden access to our smart meter data, implement SAP on S4/HANA© for improved performance and easier data access, and implement a virtual data warehouse to improve ability to share both enterprise and business specific data across business functional areas. In addition, implement a telematics solution for fleet data analytics, fleet asset management and fleet operations, as well as a platform for asset investment planning and asset performance management to enable business outcomes such as enhanced condition based maintenance and predictive maintenance. Continue to leverage the Province of BC and TELUS Strategic Innovation Fund to explore implementation of an enterprise data collection platform (internet-of-things) to support business outcomes related to worker and public and dam safety.
ENERGY MANAGEMENT	BC Hydro's grid modernization work identified opportunities for improving operations, security, safety and visibility to the grid with many of these improvements involving the deployment of digital technologies. Our approach is to take advantage of these opportunities on a case-by-case basis depending on their ability to meet our strategic objectives, the priorities of our organization, the maturity of the technologies and business constraints. Continue to upgrade our Energy Management System and Outage Management System (PowerOn) to maintain product support, and work to extend the use of our smart meter data to support outage management objectives. Implement an integrated Advanced Distribution Management System to improve performance, meet business outcomes and align with product vendor direction.

BC Hydro Power smart

Technology Strategy

Critical success factors

Delivery of the strategy demands that we address some non-technical factors that will be critical to success:

1. **Early engagement with our business leaders on strategic direction.** Technology must be recognized as necessary to achieving the goals of the organization. Technology leaders must be invited to work closely with business leaders during their planning to understand the strategic objectives and advise on opportunities for technology enablement.

2. **Streamline our delivery processes to be fit for purpose.** We have a robust IT delivery process (ITDSP) which has served us well in providing strong guidance and oversight of our project delivery function. This process does not scale adequately for our lower risk project activity nor provide the agility needed for user facing capability development. We are developing alternative delivery models (both variants to ITDSP as well as 2-speed or agile models) to meet the needs of modern technology deployment.

3. **Resource availability and reduction in capacity bottlenecks.** Project initiation decisions must consider not only capital investment availability. Equal emphasis is required for the availability of operating funds to support the non-capital project costs and on-going sustainment costs, and availability of resources to deliver and support pre-project and project delivery activities.

4. **Portfolio management prioritization and selection processes.** Capital investment prioritization and selection must be based on a common value framework for the organization and an integrated selection process that allows for trade-offs in non-sustainment investments. Investment decisions are subject to the application of constraints due to funding, resource capacity, available skill sets, sustainment capabilities, and ability of the organization to absorb change.

5. **Funding**. The current funding model based on capital investment for technology does not support future subscription and cloud services investments that typically require operating funds. A new funding model is required to ensure the success of future technology investment and operations.

6. **Governance, risk and compliance.** Continued central governance of systems architecture and project delivery is required to optimize resources and ensure compliance with security, privacy, delivery and architecture standards and policies.

BC Hydro
Power smart

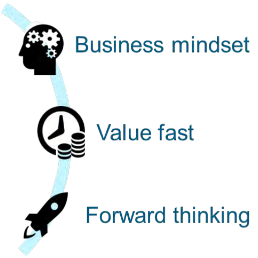
5-Year Plan

- Developing the plan
- Future business outcomes
- Prioritization and constraints
- Investment summary
- Measuring our success
- Conclusion

BC Hydro
Power smart

New in Fiscal Year 2021

5-Year Plan



This year's 5-Year Plan has been refreshed to reflect the priorities and initiatives expected over the next five years under the current capital investment plan.

After the application of prioritization and constraints, our investments over the next five years are driven primarily by compliance, security and sustainment. With the completion of the Supply Chain Applications project, we are now planning for a future initiative to meet BC Hydro's work management objective. Pre-initiation work on Enterprise Asset and Work Management will provide us with the information we need on costs, benefits and approach to proceed with an investment designed to achieve our productivity and cost efficiency objectives.

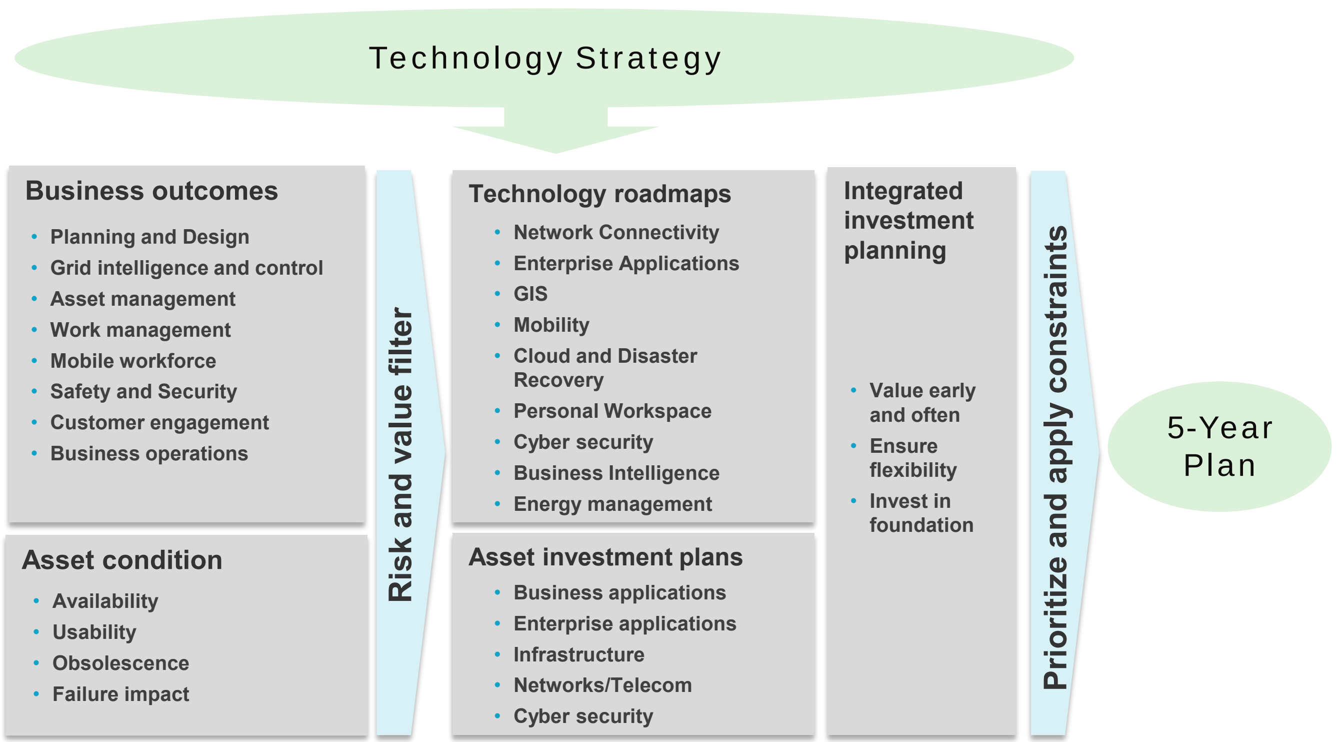
Pre-initiation work is also underway for migrating our core SAP system to S4/HANA. SAP HANA is SAP's in-memory database which provides technical capabilities to run transactions much faster and simpler access to the data. SAP S/4 HANA is a new version of SAP application that runs on SAP HANA database leveraging the power of in-memory computing. This version of SAP has a dramatically simplified data model, faster processing, advanced real-time data analytics capabilities and a modern user experience. It also provides options for robotic process automation, machine learning and artificial intelligence capabilities.

All compliance and security related initiatives are included in the capital plan including incremental investment that may be required as an outcome of the compliance technology roadmap work. Any major compliance or cybersecurity initiative resulting from the compliance technology roadmap work is not included.

5-Year Plan

Developing the plan

Fundamentally, the objective of the Technology group is to enable business outcomes and sustain the availability and security of our existing assets.



BC Hydro Power smart

5-Year Plan

Developing the plan

In developing this Plan, the Technology group facilitated over twenty workshops with business group leaders to identify desired business outcomes for the next five to ten years. Over two hundred outcomes were articulated, with approximately half of those dependent on a technical solution. These outcomes were assessed for value based on executive and senior management's best judgement on their contribution to meeting our strategic objectives. This information is reviewed and confirmed annually and is used to inform our technology roadmap development and investment planning.

The condition, health and longevity of our assets are also assessed annually by our Technology team. Our Business Partner Services team also use their best judgement in how well the business and enterprise applications are meeting the needs of BC Hydro. This information, together with the impact of lost availability, is used to inform our technology asset investment plans.

Integrated investment planning activities bring together the technology roadmap view, the asset investment view, and alignment with business expectations. The result is our aspiration for technology investment. Application of selection and prioritization criteria, as well as funding and resource constraints, leads to the development of the five year plan.

This 5-Year Plan shows the investments currently anticipated based on BC Hydro's capital plan for the next five years. With the application of prioritization and constraints, our investments over the next five years will be driven primarily by compliance, security and sustainment. This year, we begin planning for opportunities to improve business capabilities in priority areas. These plans allow us to initiate investment as resources become available. Priority investments are those that provide opportunities for improving compliance outcomes, making it easier to get work done and achieving operational efficiencies.

5-Year Plan

Future business outcomes

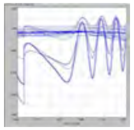
Our Technology team reviewed and aggregated the business outcomes for commonalities and determined the underlying technology investment needed. This is a summary of the aggregated business outcomes.

VALUE STREAMS

BUSINESS OUTCOMES

PLANNING & DESIGN

- Enhanced load forecasting and energy planning
- Enhanced engineering design



GRID INTELLIGENCE & CONTROL

- Distribution grid management
- Demand response management
- Digital substations
- Distributed energy resource management
- Resilient tele-communications networks

ASSET MANAGEMENT

- Integrated and optimized investment planning
- Asset performance management
- Asset intelligence for operations
- End-to-end asset management

WORK MANAGEMENT

- Operations work planning and scheduling
- Optimized planned outage management
- Real-time monitoring and management of work

MOBILE WORKFORCE

- Ability to complete job on site
- Safety practices integrated into work process on site
- Work site awareness
- Real-time visibility to grid status on site
- Ability to collect quality information from the field

SAFETY AND SECURITY

- Resilient and secure IT and OT systems
- Real-time situation awareness during emergencies
- Physical grid security
- Automated facility security
- Enhanced dam safety systems

CUSTOMER ENGAGEMENT

- Customer inclusion in conservation and electrification programs
- Improved outage and restoration information
- Customer work booking
- Optimized customer service interactions

BUSINESS OPERATIONS

- Optimized supply chain function
- Optimized back office processes
- Enhanced data access and business intelligence
- Improved information, records management, search
- Improved employee experience, productivity and collaboration
- Workforce planning and development

5-Year Plan

Prioritization and Constraints

There are many opportunities for utilizing technology to unlock value in BC Hydro but it is not possible to achieve all outcomes all at once. Therefore, it is necessary to **prioritize** the outcomes and focus on those which we consider most important to the organization. In general, mandatory initiatives needed to address *compliance and security* are the highest priority and critical initiatives that address *risk management and sustainment of productivity* are next.

Initiative / Investment	Description
Enhance our Capability	Discretionary activities that provide new or improved business capabilities
Manage our Risk and Sustain Productivity	Critical activities needed to ensure reliable and safe operations and to maintain the current level of productivity for our users
Compliance & Security	Mandatory activities needed to meet government/BCUC/NERC/WECC requirements

Initiatives that *enhance our capability* are considered discretionary and are third in priority ranking. It should be noted, however, that these initiatives may provide significant benefits and help us in achieving our strategic objectives.

Once prioritized, it is necessary to apply our **constraints** in order to develop a plan that can be delivered with confidence. We apply a number of critical constraints including,

- The Technology team capacity
- Capital and operating funding
- Business capacity for change
- Availability of BC Hydro and contractor support resources
- Technical dependencies
- Technology maturity

5-Year Plan

Investment summary

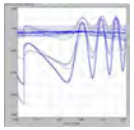
Under the current constraints, work will continue to complete projects underway and a limited number of new business value initiatives will be undertaken. The bolded outcomes are those that are wholly or partially addressed by major planned initiatives.

VALUE STREAMS

BUSINESS OUTCOMES

PLANNING & DESIGN

- Enhanced load forecasting and energy planning
- **Enhanced engineering design**



GRID INTELLIGENCE & CONTROL

- **Distribution grid management**
- Demand response management
- Digital substations
- Distributed energy resource management
- Resilient tele-communications networks

ASSET MANAGEMENT

- Integrated and optimized investment planning
- Asset performance management
- Asset intelligence for operations
- **IT and OT system asset management**

WORK MANAGEMENT

- **Operations work planning and scheduling**
- Optimized planned outage management
- Real-time monitoring and management of work

MOBILE WORKFORCE

- **Ability to complete job on site**
- **Safety practices integrated into work process on site**
- Work site awareness
- Real-time visibility to grid status on site
- **Ability to collect quality information from the field**

SAFETY AND SECURITY

- **IT and OT system security and resilience**
- Real-time situation awareness during emergencies
- **Physical grid security**
- Automated facility security
- **Enhanced dam safety systems**

CUSTOMER ENGAGEMENT

- **Customer inclusion in conservation and electrification programs**
- Improved outage and restoration information
- **Customer work booking**
- **Optimized customer service interactions**

BUSINESS OPERATIONS

- **Optimized supply chain function**
- Optimized back office processes
- Enhanced data access and business intelligence
- **Improved information, records management, search**
- **Improved employee experience, productivity and collaboration**
- Workforce planning and development

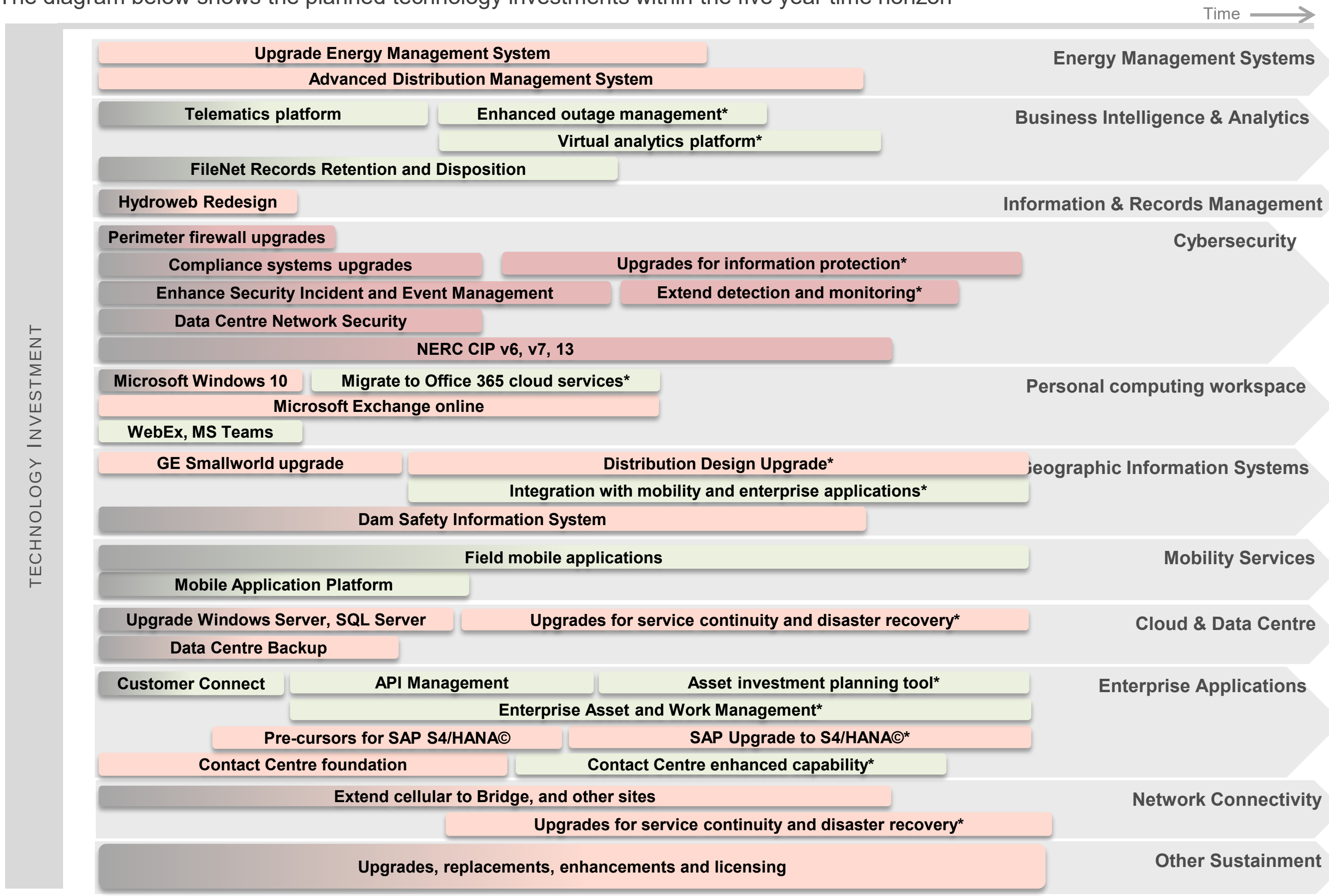
5-Year Plan

	Investment Initiatives	Business outcome
Security and Compliance	NERC CIP v6, v7, NERC CIP-013 Compliance System Upgrades Compliance Technology Roadmap	IT and OT system security and resilience Physical grid security
	Firewall Upgrades Enhance Security Incident and Event Management (SIEM) Extend Detection and Monitoring	IT and OT system security and resilience Physical grid security
Risk and Productivity Sustainment	**Upgrades:** Energy Management System (EMS), Windows 10, Exchange Online, Windows Server and SQL Server, Enterprise Mobile Application Management, GE Smallworld GIS, Contact Centre Foundation, PowerOn 4.3, Energy Analytics System GreenPlum Hardware Upgrade, SAP Technical Upgrades, API Management, WISKI Upgrade (water) **Replacement**: Surrey Campus Network, CIDC Network, FVO/SIO Network, Regional Site Infrastructure, Corporate Telephony, Data Centre Infrastructure (servers, storage, network devices), Personal Devices (PCs, Phones, Tablets), SAP Customer Management, Learning System, Advanced Distribution Management System Studies: Distribution Design Replacement and Passport Decommission Study, SAP S4/HANA Migration Study Product licensing and enhancements to ensure vendor support	IT and OT system security and resilience IT and OT systems asset management
	Extended Cellular to Dam Facilities Dam Safety Information System	Enhance dam safety systems
Enhance Business Capability	Customer Connect Web Enablement Enable Voluntary Time-based Rates	Optimized customer services interactions Customer inclusion in conservation and electrification programs
	WebEx, Microsoft Teams Enterprise Hydro Web (Intranet) Redesign FileNet Records Retention and Disposition	Improved employee experience, productivity and collaboration Improved information, records management, search
	Field mobile applications Mobility Application Platform	Ability to complete job on site Ability to collect quality information from the field Safety practices integrated into work processes on site
	Studies: Enterprise Asset and Work Management Study, Lines Asset Hierarchy Study, Contractor Lifecycle Study	Operations planning and work scheduling
	Telematics Platform	Asset intelligence for operations

5-Year Investment Plan

Investment Summary

The diagram below shows the planned technology investments within the five year time horizon



26

*Those initiatives with an asterisk are not included in the F21 current capital portfolio.

5-Year Plan

Measuring our success

The Technology group has a variety of ways to track and measure the success of our capital investments. These range from the immediate and quantifiable, such as operational and delivery metrics, to the completely qualitative business satisfaction survey. We recently introduced a benefits tracking process for business capability driven initiatives. In this process both quantitative and qualitative assessments are made over a period of time following deployment of a solution.

- **Operational Metrics** – Technology uses a number of metrics to evaluate and track the performance of our systems, services, and vendors.

- **Delivery Metrics** – Technology uses a number of metrics to assess and track the performance of our delivery which include measures on cost, schedule, and quality.

- **Business satisfaction** – Technology conducts an annual satisfaction survey to solicit feedback from across the business of the level of satisfaction with Technology delivery and services.

- **Project Benefits** – Benefits from initiatives undertaken as part of implementing technology solutions will be tracked to assess how well they deliver on the expectations set out in their respective business cases.

Technology Strategy and 5-Year Plan

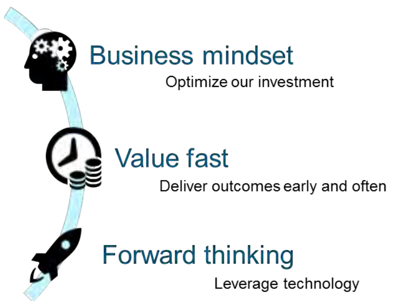
Conclusion

Our strategy describes BC Hydro's landscape and the drivers that influence our future business and technology decisions; our overall objective is to help BC Hydro achieve its service plan goals through the use of technology. We identify eight value streams across BC Hydro through which technology can unlock significant benefits. Our approach is to operate with a *business mindset*, to deliver *value fast*, and to be *forward thinking* in all we do.

BC Hydro's 5-Year Technology Investment Plan identifies expected business outcomes from across planning, delivery, operations and business support functions. The outcomes are assessed based on their ability to help achieve our service plan objectives. Following prioritization and the application of constraints, the Plan describes the outcomes we expect to achieve in the next five years and the corresponding investments in technology.

We must also sustain and maintain our existing systems. Investments for sustainment include refreshes for infrastructure, personal devices, network, telephony and cyber security assets, as well as upgrades and replacement of business and enterprise applications.

The plan reflects corporate planning activities and uses input from BC Hydro's executive and senior managers as well as the Technology subject matter experts. BC Hydro uses an annual planning cycle to maintain currency of plans and adapt to changes. We expect to update this plan annually.



BC Hydro
Power smart

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix P

Project Write-off Costs

Table of Contents

List of Tables

1 Introduction

In its Decision on the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (**F20-F21 RRA**) , the BCUC acknowledged that some project write-offs are reasonable and to be expected in a utility's normal course of business.[1] The BCUC suggested that a regulatory account could be considered as a mechanism to capture BC Hydro's actual project write-off costs for future recovery, provided that:

> …in future RRAs BC Hydro also lists all of the projects and costs that have been written-off and captured in the regulatory account along with a description of each project, the rationale for incurring the costs and the rationale for the decision to not continue with the project. In the Panel's view, this would provide the BCUC and interveners with an opportunity to review the reasonableness of these costs.1

In response to Directive 33 of the BCUC's Decision on the F20-F21 RRA, BC Hydro applied for approval to establish a Project Write-off Costs Regulatory Account,[2] which was approved by BCUC Order No. G-337-20 dated December 17, 2020. The purpose of the account is to defer, on an ongoing basis starting in fiscal 2020, actual project write-off costs in each fiscal year where BC Hydro believes future recovery from ratepayers is appropriate. BC Hydro then provides the details in respect of completed fiscal years in its RRAs for review by the BCUC.

In its Decision on the Previous Application, the BCUC approved a recovery mechanism for the account, and accepted that the $9.3 million of actual project write-off costs incurred in fiscal 2020 should be recovered from ratepayers.

In accordance with the suggested process from the Decision on the F20-F21 RRA, this Appendix lists the projects and costs that have been written-off and captured in the regulatory account in fiscal 2021, a description of the projects, as well as the

1 BCUC Decision and Order No. G-246-20, BC Hydro F20-F21 RRA (October 2, 2020), page 107.
2 Refer to: https://www.bcuc.com/ApplicationView.aspx?ApplicationId=833.

rationale for incurring the costs and the rationale for not continuing with the projects or reducing the scope of the projects.

2 Information Considered for Project Write-Off

Project write-offs continue to be determined with reference to the accounting rules BC Hydro is required to follow. BC Hydro uses International Financial Reporting Standards guidance in reviewing capital projects for any asset impairment. Specifically, International Accounting Standards 36 – *Impairment of Assets* – provides the following guidance:

> An entity shall assess at the end of each reporting period whether there is any indication that an asset may be impaired. If any such indication exists, the entity shall estimate the recoverable amount of the asset.

Active capital projects are not yet assets in service, but from an accounting perspective are still assets on the balance sheet classified as work in progress. BC Hydro reviews capital projects each month based on the standard noted above for any internal or external information to determine if an impairment exists and if so, the amount of the project that needs to be written off. If a project or any part of the project is to be written off, a justification is prepared by the project team and presented to the appropriate level of management for approval, depending on the amount of the write-off.

Projects are similarly reviewed throughout the project lifecycle. Specifically, at the end of each phase of the project lifecycle, BC Hydro determines whether a project should proceed to the next phase of the project lifecycle, be cancelled or be reduced in scope. If a project is cancelled or reduced in scope, the expenditures on that project are reviewed against the standard noted above to determine any impairment and resulting write-off.

Pursuant to the processes outlined above, and consistent with the Previous Application, key reasons why an impairment may occur and a write-off may be required include the following:

1. **Cost**: Detailed design work may indicate that the costs of the original leading alternative are higher than originally planned, which may result in another alternative being more cost-effective. If it is determined that another alternative will be pursued as a result, some or all of the costs incurred in respect of the original leading alternative may hold no future value (i.e., are impaired) and may be required to be written off;
2. **Technical Issue**: Detailed engineering work may indicate that the original leading alternative has technical issues that were not previously known. Examples are challenges associated with retro-fitting new equipment with existing equipment of a different vintage, or the identification of damage or poor condition of assets that were not being replaced once a sealed asset is opened. Another example of a technical issue is where information developed may reveal a new alternative that is determined to be superior to the original leading alternative. If these examples result in changes to the leading alternative or the pursuit of another alternative, some or all of the costs incurred to that point may be impaired and may be required to be written off;
3. **Business Driver**: Business factors, such as the load forecast, could push the need for a project that is currently underway to a future period. In this instance, depending on factors such as the length of time before the project may be needed in the future and the likelihood of future need, some or all of the costs incurred to that point may be impaired and may be required to be written off; and
4. **Customer's Need**: A project to interconnect a customer may be cancelled or the scope changed because the customer has changed its request. A customer could also cancel a load request that had a reinforcement project to existing

BC Hydro assets to support the new load. In this instance, some or all of the costs incurred to that point may be impaired and may be required to be written off.

3 Project Write-Offs in Fiscal 2021

BC Hydro's actual project write-offs in fiscal 2021 were $9.6 million. BC Hydro is not seeking recovery of $2.3 million of this amount as BC Hydro does not believe it would be reasonable for ratepayers to pay for the costs in these instances. Accordingly, BC Hydro has deferred $7.3 million ($9.6 million minus $2.3 million) to the Project Write-off Costs Regulatory Account in fiscal 2021 and proposes to recover this amount from ratepayers over the Test Period in accordance with the approved recovery mechanism for the account.

Table P-1 provides the itemized project write-offs deferred to the Project Write-off Costs Regulatory Account in fiscal 2021.

Table P-1 Project Write-Off Amounts deferred in Fiscal 2021

Project Name	Amount Deferred ($ million)	Project Description	Rationale for Write-off
Chilliwack Facility Project	2.1	This project was to construct a new building to accommodate the combined operational needs of the current Chilliwack (a leased facility) and Atchelitz (adjacent to the substation) field offices.	Technical Issue. During the early Definition Phase in the project, BC Hydro had identified a suitable property, reached a conditional agreement on the property acquisition with the property owner, and proceeded with the building design in parallel with the property owner seeking final approval from the Agricultural Land Commission (ALC). The property acquisition was ultimately unsuccessful due to the property owner deciding not to accept the conditions of development required by the ALC. Subsequently, BC Hydro conducted multiple attempts to locate a suitable site; however, all were unsuccessful. $2.1 million of costs associated with the building design and property site project management could not be utilized in the future and were written-off.
Jordan River (JOR) Fire Risk Reduction	1.6	This project was to address the deficiencies in the existing fire protection piping, increase the reliability of the fire protection water supply and to implement general fire risk reduction measures in high risk areas at the JOR Powerhouse. The scope of the project included the replacement and expansion of the fire protection piping throughout the powerhouse, the replacement of the cladding on the west side of the powerhouse, and the upgrade of the fire protection supply water pressure reducing system.	Technical Issue and Cost. Upon installation, BC Hydro made multiple attempts to commission the Fire Protection supply water pressure reducing system. The new valves were installed according to specifications but did not perform as expected in the new piping configuration. Outage availability at the facility is low and rather than continue to troubleshoot the new valves and new piping design, it was decided to advance an alternate design as a lower risk approach to resolving the technical challenges. As a result of the design change, costs incurred related to the abandoned design and installation of $1.6 million were written-off.

Project Name	Amount Deferred ($ million)	Project Description	Rationale for Write-off
Lake Buntzen 1 - Coquitlam Tunnel Gates Refurbishment	1.3	This project was to address the safety and environmental risks by improving the reliability of the Coquitlam tunnel gates for control of water conveyance from the Coquitlam Reservoir to Buntzen Lake Reservoir.	Technical Issue. Due to the complexity of the project (modifying an existing underground tunnel) and lack of BC Hydro personnel with experience in this area, BC Hydro used a multi-stage public procurement process which is a common approach for complex projects. The process included stages for prequalification, request for proposal and the selection of two engineering consulting firms with relevant experience to develop detailed design and construction proposals. This approach was selected to ensure innovation in design and methodology in a competitive bidding environment. BC Hydro provided engineering support to both consulting firms during the development of the preliminary designs. One of the two designs was ultimately rejected due to higher cost and a construction methodology that had higher safety and quality risks. As a result, costs of $1.3 million associated with the preliminary design not selected and BC Hydro's support leading to the completion of that design, were written-off as they are not directly attributable to the project and the assets being constructed. Although the approach to engage two engineering firms resulted in a project cost write-off, BC Hydro derived important benefits from working with two proponents by receiving an optimal design option that addresses the constructability and safety risks at the lowest cost, with expected cost savings for the overall project. Notably, the winning bid was approximately $10.9 million less than the competitor's bid and had a safer construction methodology.

Project Name	Amount Deferred ($ million)	Project Description	Rationale for Write-off
Jordan River (JOR) Generating Station Upgrade Governor & PRV Controls	0.8	The JOR Generation Station has a 150 MW generator with an electro-hydraulic governor, and a Pressure Regulating Valve (PRV) that is connected to the servo motors/wicket gate via a mechanical linkage. This project started in 2016 and was to address the JOR Generating Station governor controls that were operating beyond their expected life. Failure of the governor and PVR controls could lead to damage to the penstock.	Technical Issue. During the Identification Feasibility Design Stage of the project, BC Hydro engaged a firm specializing in governor design to study the existing system. Full replacement of the governor and PRV controls was selected as the leading alternative. The Feasibility stage design was based on a system installed in a facility in California but, due to issues with the facility owner, a visit to the installation was not possible before the leading alternative was finalized. During Preliminary Design, it was discovered that the replacement design would require extensive and expensive changes to work at the JOR Generating Station. The team reviewed the proposed design changes and, given the high design risk and cost risk due to these changes, the team selected retrofitting the existing equipment as the leading alternative. As a result, costs of $0.8 million incurred related to the original leading alternative were written-off as they are not directly attributable to the project and the assets being refurbished.
Asset Investment Planning Tool Project	0.5	The project was to support and implement process and technology changes to enable a consistent, transparent and more objective approach to asset investment planning and management across BC Hydro.	Cost and Technical Issue. BC Hydro cancelled the Asset Investment Planning (AIP) Tool project due to increased expected total project cost and to align the project with the implementation of an Enterprise Asset Management (EAM) software platform. In its Decision on the Previous Application, the BCUC requested that BC Hydro "explain the prudency of its project expenditures given BC Hydro's explanation that the project is not cost-effective because its EAM software needs to be implemented first." BC Hydro provides the following explanation. The objective of the AIP Tool project, approved in June 2018, was to implement process and technology changes to enable a consistent and more objective approach to asset investment planning across the company. At that time, BC Hydro identified incremental improvements to our capital planning process, that did not require integration with the asset information systems, and were not dependent on the implementation of EAM software. During the Definition (design) phase of the project, the design specifications were further evaluated and the vendor and pricing information was updated to align with the new understanding of the requirements of the project. This pricing was

Project Name	Amount Deferred ($ million)	Project Description	Rationale for Write-off
			considerably higher than the Definition phase estimate and the project was put on hold in June 2019 to allow time to reassess the business case. In reassessing the business case, BC Hydro determined that the full benefits of an AIP Tool project could be achieved only if an EAM software platform was first implemented that allowed asset health information, asset life-cycle management and financial information to be integrated for asset investment planning purposes. Implementation of an AIP Tool prior to an EAM platform would result in a standalone AIP tool without detailed asset information which would be reliant on manual data integration from multiple IT systems. Considering the higher pricing estimates and with a better understanding of the available tool capabilities, BC Hydro determined that the incremental benefits without integration could not be justified. This information on pricing and capabilities could only be understood as BC Hydro worked through design specifications with the vendor and was not known at the time that the project was approved in June 2018. BC Hydro is initiating the Stations Work Management project in fiscal year 2022. This project will form the foundation for the EAM platform and is expected to be completed in fiscal year 2025. In September 2020, the project team presented these findings to the project steering committee and project sponsor. Since the capital planning process was already considered robust and achieving the potential of asset investment planning would require prior implementation of an EAM software platform, the steering committee and project sponsor endorsed the recommendation to cancel the project. The project was cancelled in October 2020. As a result of the project cancellation, $0.5 million of costs incurred were written-off. BC Hydro may initiate a new project after the implementation of the EAM Software Platform to realize the full benefits of an AIP Tool. Any such project would go through the standard Technology portfolio selection process. Additional information related to this project is included in Chapter 6, section 6.1.3.4.

Project Name	Amount Deferred ($ million)	Project Description	Rationale for Write-off
Bridge River 1 Slope Drainage Improvements	0.5	The project was to design and implement mitigation measures to reduce the risk of debris flows at the Bridge River 1 Facility and to reduce the associated risk of loss of life to acceptable levels.	Technical issue. Work associated with the project, such as characterization of the Bridge River 1 slope materials and inspection of the slope drainage system was carried out starting in 2012. The original project recommendation was to proceed with creating a channel through the existing spoil pile in the School Creek hill slope as a means of reducing but not eliminating the landslide risk. However, in 2014, the project was made aware of the potential for the downslope school site to be developed for permanent occupation requiring the project to refine its approach to the drainage design. BC Hydro then advanced a strategy to acquire and limit the use of the school site property to eliminate the risk of loss of life. However, after lengthy negotiations, BC Hydro was unable to agree to terms that would result in BC Hydro acquiring and/or limiting the use of the school site property. It was concluded in 2020 that the solution to be advanced would be the full removal of the spoil pile plus drainage improvements. The originally selected channelization alternative was no longer considered viable. Upon review of the project costs, it was determined that costs of $0.5 million associated with the channelization alternative could not be used for the new leading alternative and were written-off as they are not directly attributable to the revised project scope and the assets being constructed.
Project Write-Offs equal or less than $200K	0.5	Various minor expenditures on projects (each less than $200,000) across the capital portfolios.	A total of thirteen projects with minor expenditures where it was determined to be appropriate to cancel the project or proceed with a reduced scope.
Total Write-Off Amounts	7.3		

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix Q

Reliability Indices

BC Hydro
Power smart

Chris Sandve
Chief Regulatory Officer
Phone: 604-623-3918
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

June 4, 2021

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Annual Reporting of Reliability Indices
Annual Response to Directive 26 of BCUC Decision on F2005/F2006 Revenue Requirements Application (F05/F06 RRA)

BC Hydro writes to provide an annual reporting of reliability indices, as required by Directive 26 of BCUC Order No. G-96-04 on BC Hydro's F2005 to F2006 Revenue Requirements Application.[1]

Directive 26 states that BC Hydro is expected to present reliability indices (SAIFI, SAIDI, CAIDI, ASAI, SARI, MAIFI, generation forced outages, availability, and generation outage rates), both combined and disaggregated (where applicable), on an annual basis with comparisons to Canadian Electricity Association (**CEA**) averages.

In this filing, BC Hydro is providing reliability indices for distribution, transmission and generation performance through fiscal 2021. As in previous years, BC Hydro reliability statistics are provided on a fiscal year basis and compared with the CEA calendar year data.

1 BC Hydro submitted its initial distribution and generation reliability indices compliance filing in September 2005, and subsequently reported the available reliability indices in May 2006 as part of the F2007/F2008 RRA. Starting in May 2007, BC Hydro began filing annual reports with the Commission on these reliability indices. Transmission system reliability indices for the years prior to fiscal 2012 were provided separately by the British Columbia Transmission Corporation (**BCTC**) in its Transmission System Capital Plan filings. BC Hydro provided the transmission system reliability indices starting in fiscal 2012, subsequent to the integration of BC Hydro and BCTC in fiscal 2011.

Distribution and Transmission Update

The most recent annual CEA reports for distribution and transmission are the 2019 Annual Service Continuity data on Distribution System Performance in Electrical Utilities and the Bulk Electricity System. CEA data on distribution and transmission performance for the 2020 calendar year are not yet available. The comparative reliability indices, both combined and disaggregated, for BC Hydro's distribution and transmission systems, are presented in Attachment 1, in tabular and graphical form through to fiscal 2021.

Generation Performance Update

The most recent annual CEA report on generation performance is the 2019 Generation Equipment Status Annual Report. CEA data on generation performance for the 2020 calendar year are not yet available.

The comparative reliability indices, both combined and disaggregated, for BC Hydro's generation system are presented in Attachment 2, in tabular and graphical form for the 10-year period ending fiscal 2021.

To reflect BC Hydro's investment strategies and operating practices of prioritizing Key Generating Facilities (large MW capacity units) over Available Generating Facilities (small MW capacity units), weighted averages of the reliability indices are also included in Attachment 2. CEA weighted averages for these indices were not available at the time of submission and will be provided for comparison starting next year. BC Hydro will continue to include this additional information in future reports.

Reliability Indices Performance Highlights

BC Hydro highlights the following with regard to its reliability indices performance through fiscal 2021:

- BC Hydro's SAIFI results (blue line) continue to perform better than the CEA community average (red line);
- On average, BC Hydro's SAIDI performance is better than the CEA average SAIDI;
- On average, BC Hydro's CAIDI performance is within 15 minutes of the CEA average CAIDI, except during years of notable storm events;
- BC Hydro's Transmission SAIDI and DPUI (Delivery Point Unavailability Index) performance are higher than previous years due to more outages and longer duration outages to our Transmission Voltage Customers;
- For generation, all aggregate reliability measures included improved slightly in fiscal 2021 compared to fiscal 2020;

- The aggregate measures (all plants) for forced outage factor and availability factor were negatively impacted by our smallest facilities with the main contributor being the forced extension of a planned outage at Aberfeldie due to leaks found in the penstock, which were subsequently repaired;
- On average, BC Hydro's aggregate availability factor is lower than the CEA average by 5 per cent to 7 per cent as BC Hydro spends more time than the CEA average on planned outages; and
- The 60-Month Rolling Forced Outage Factor for Key Facilities, which is included as one of BC Hydro's Service Plan metrics, was 1.21 per cent at the end of fiscal 2021, which meets the Service Plan target of less than or equal to 1.8 per cent.

For further information, please contact Chris Sandve at 604-974-4641 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Chris Sandve
Chief Regulatory Officer

ls/rh

Enclosure

F05/F06 Revenue Requirements Application

Annual Response to Directive 26 of BCUC Decision

F2021 Annual Reporting of Reliability Indices

Attachment 1

Distribution and Transmission Reliability Indices

This section includes the following distribution and transmission indices:

SAIFI	a measure of the number of sustained interruptions (longer than one minute) an average distribution customer will experience in a year
T-SAIFI-MI	a measure of transmission interruptions of less than one minute in duration that a delivery point experiences in a year
T-SAIFI-SI	a measure of transmission interruptions of one minute or more that a delivery point experiences in a year
T-SAIDI	a measure of the average total interruption duration, in hours that a delivery point experiences in a year
SAIDI	a measure of the amount of time, in hours, an average distribution customer is without power in a year
CAIDI	a measure of the average interruption, in hours, per interrupted distribution customer in a year
%ASAI	a measure of the percentage of time service is available in the year
CEMI-4	percentage of customers experiencing four or more outages in a year
MAIFI	a measure of the frequency of momentary (less than one minute) interruptions per distribution customer served in a year
DPUI	a measure of overall bulk electricity system performance in terms of a composite index of unreliability expressed in system minutes in a year. It takes into account all forced and planned outages except interruptions attributed to generators
SARI	a measure of the average restoration time, in hours, for each transmission delivery point in a year

As noted in Provision 9x of the F2011 Revenue Requirements Application Negotiated Settlement Agreement, BC Hydro is also reporting its CEMI-4 reliability metric, and SAIFI, SAIDI, CAIDI, ASAI, and CEMI-4 metrics normalized using the IEEE 2.5 Beta method. CEMI-4 is not benchmarked externally as utilities are at varying stages in their development of this metric.

Table 1 Reliability Indices – BC Hydro Overall and CEA Overall (All-Event Indices, Not Normalized)

Year	BC Hydro Overall				CEA Overall			
	SAIFI	SAIDI	CAIDI	%ASAI	SAIFI	SAIDI	CAIDI	%ASAI
F2012	1.92	5.08	2.65	99.942	2.63	6.16	2.34	99.930
F2013	1.59	3.70	2.33	99.958	2.54	4.66	1.83	99.947
F2014	1.83	5.19	2.83	99.941	2.72	9.49	3.49	99.892
F2015	1.72	5.11	2.97	99.942	2.39	6.38	2.67	99.927
F2016	2.29	10.69	4.66	99.878	2.32	5.08	2.19	99.942
F2017	2.17	5.50	2.53	99.937	3.10	5.65	1.82	99.936
F2018	2.13	6.56	3.08	99.913	2.61	7.91	3.04	99.910
F2019	1.90	8.58	4.51	99.902	2.84	8.46	2.98	99.903
F2020	1.96	4.78	2.44	99.945	2.65	8.38	3.16	99.904
F2021	1.98	5.73	2.90	99.935	n/a	n/a	n/a	n/a

Table 2 Reliability Indices – BC Hydro (Distribution) and CEA (Distribution) (All Event Indices, Not Normalized)

Year	BC Hydro (Distribution)				CEA (Distribution)			
	SAIFI	SAIDI	CAIDI	%ASAI	SAIFI	SAIDI	CAIDI	%ASAI
F2012	1.37	4.40	3.22	99.950	2.09	5.59	2.68	99.936
F2013	1.06	3.08	2.92	99.965	1.86	4.13	2.22	99.953
F2014	1.45	4.66	3.20	99.947	2.05	8.59	4.19	99.902
F2015	1.34	4.44	3.31	99.949	1.79	5.67	3.16	99.935
F2016	1.91	10.13	5.30	99.884	1.79	4.54	2.53	99.948
F2017	1.74	4.83	2.77	99.945	2.44	5.08	2.08	99.942
F2018	1.69	5.82	3.44	99.934	2.05	5.33	2.60	99.939
F2019	1.63	8.08	4.95	99.908	2.23	7.16	3.21	99.918
F2020	1.41	3.83	2.71	99.956	2.10	7.51	3.57	99.914
F2021	1.61	4.91	3.05	99.944	n/a	n/a	n/a	n/a

Table 3 **Reliability Indices – BC Hydro Overall – Normalized using IEEE 2.5 Beta Method**

Year	BC Hydro Overall – Normalized using IEEE 2.5 Beta method				
	SAIFI	SAIDI	CAIDI	CEMI-4 (%)	%ASAI
F2012	1.67	3.89	2.34	15.37	99.956
F2013	1.46	3.33	2.28	10.45	99.962
F2014	1.68	4.14	2.46	12.52	99.953
F2015	1.35	3.37	2.49	10.13	99.962
F2016	1.60	3.42	2.14	14.00	99.961
F2017	1.88	4.37	2.33	16.43	99.950
F2018	1.67	3.94	2.36	14.55	99.955
F2019	1.39	3.21	2.32	10.65	99.963
F2020	1.68	3.56	2.12	14.59	99.959
F2021	1.56	3.52	2.25	19.19	99.960

Table 4 **Reliability Indices – BC Hydro CEMI 4 Overall (All-Event Indices, Not Normalized)**

Year	BC Hydro Overall
	CEMI-4 %
F2012	17.43
F2013	12.88
F2014	15.10
F2015	15.15
F2016	23.77
F2017	19.45
F2018	20.87
F2019	17.14
F2020	18.39
F2021	20.17

Note: CEA does not survey for CEMI-4 or IEEE 2.5 Beta.

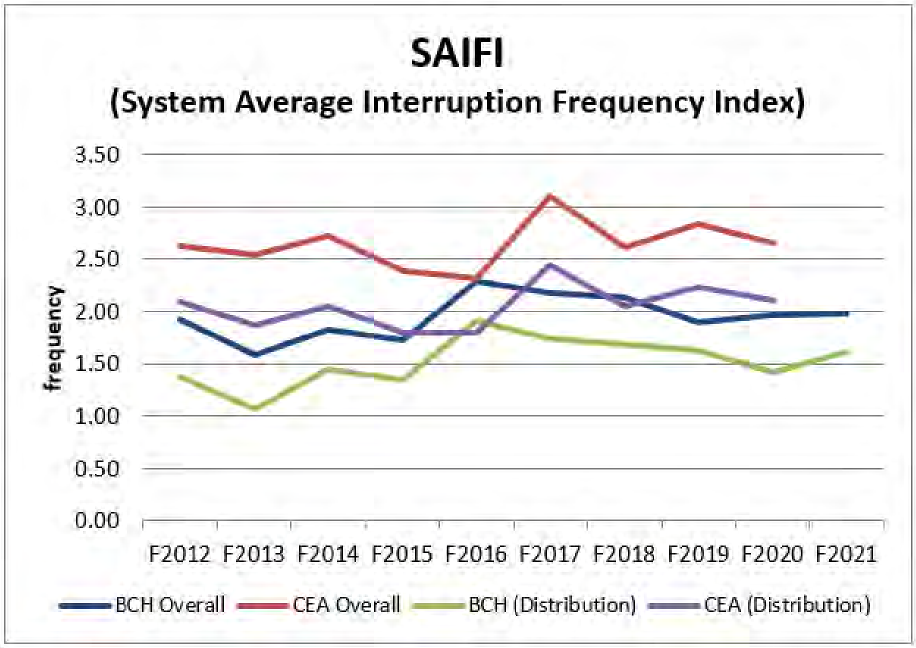
Table 5 Reliability Indices – BC Hydro (Transmission) and CEA (Transmission) (Forced Data) (All-Event Indices, Not Normalized)

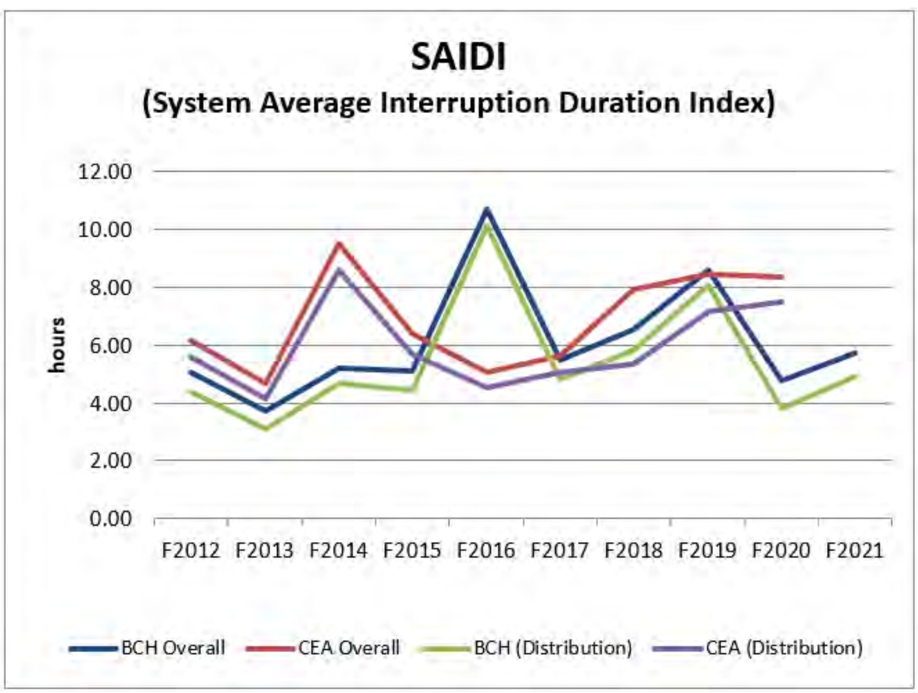
Year	BC Hydro (Transmission) (Forced)					CEA (Transmission) (Forced)				
	T-SAIFI-MI	T-SAIFI-SI	T-SAIDI	DPUI	SARI	T-SAIFI-MI	T-SAIFI-SI	T-SAIDI	DPUI	SARI
F2012	0.43	0.86	1.55	19.39	1.81	0.84	0.81	1.73	23.35	2.13
F2013	0.56	0.74	1.64	17.16	2.19	0.84	0.90	4.48	51.18	4.98
F2014	0.74	0.87	2.57	25.18	3.01	0.86	0.83	2.59	27.07	3.11
F2015	0.83	0.74	2.11	26.41	2.86	0.72	0.83	2.56	19.24	3.10
F2016	0.79	0.63	2.46	27.77	3.90	0.85	0.74	2.15	15.60	2.90
F2017	0.63	0.61	2.52	33.61	4.13	0.70	0.75	1.93	22.33	2.58
F2018	0.30	0.69	2.50	30.13	3.62	0.55	0.77	2.24	20.02	2.90
F2019	0.57	0.34	0.92	7.61	2.71	0.65	1.06	3.48	33.87	3.27
F2020*	0.90	0.89	2.74	46.30	3.08	0.82	0.89	2.63	30.07	2.94
F2021	0.70	0.75	7.10	64.75	9.47	n/a	n/a	n/a	n/a	n/a

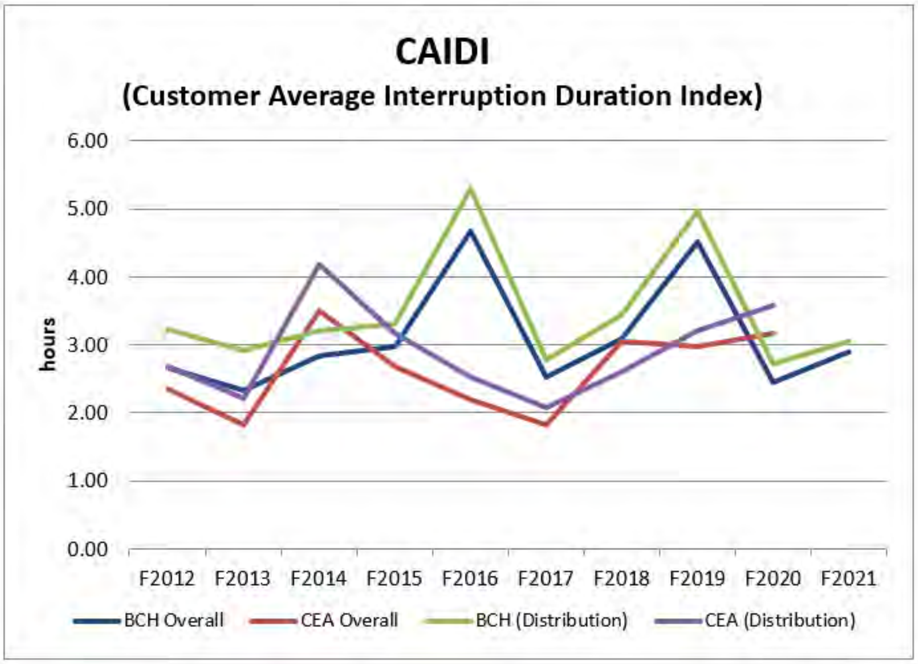
Note: The CEA Bulk Electricity Study program reports only on forced outage results as not all the participating utilities report planned outages.

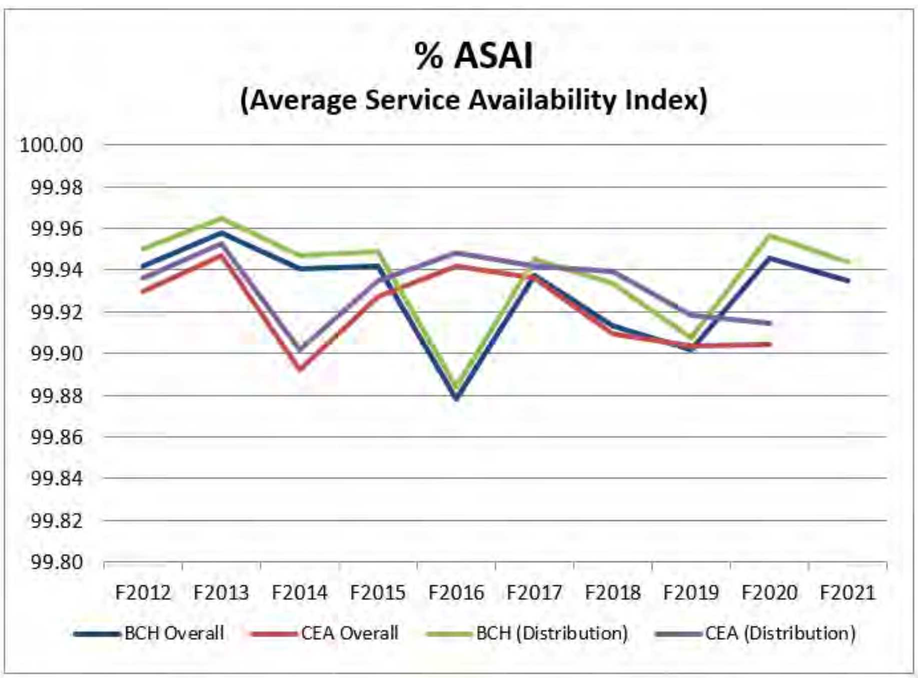
* F2020 BC Hydro (Transmission) Forced numbers filed last year were incorrect; the table has been updated to reflect the corrected numbers.

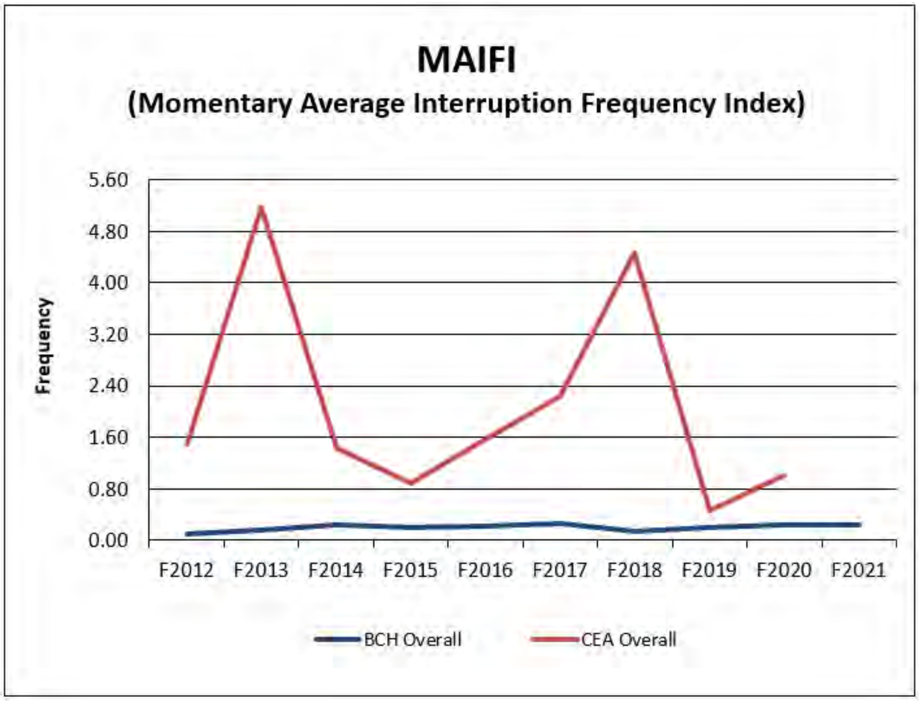
Distribution Graphs





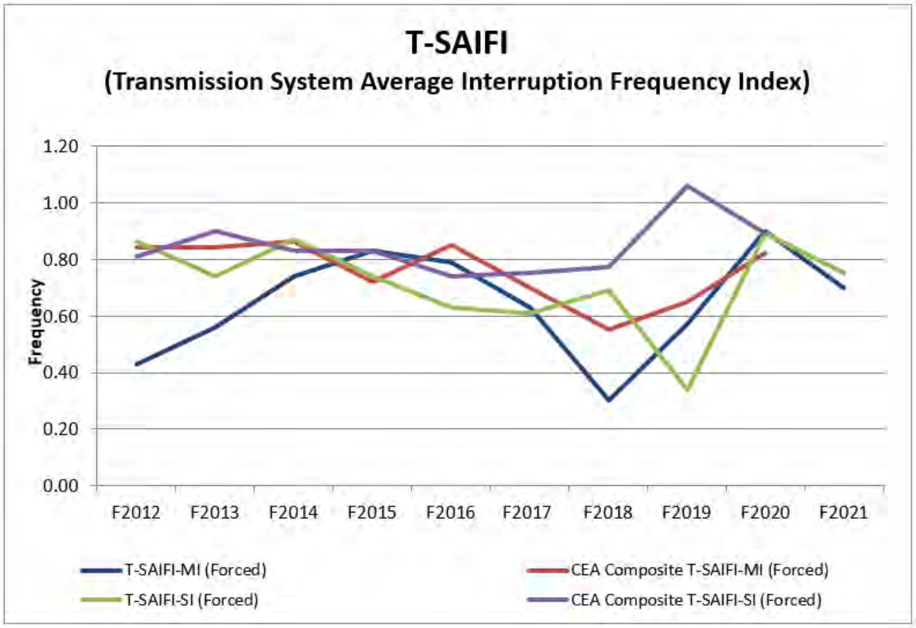

CAIDI
(Customer Average Interruption Duration Index)
hours
6.00
5.00
4.00
3.00
2.00
1.00
0.00
F2012 F2013 F2014 F2015 F2016 F2017 F2018 F2019 F2020 F2021
BCH Overall
CEA Overall
BCH (Distribution)
CEA (Distribution)

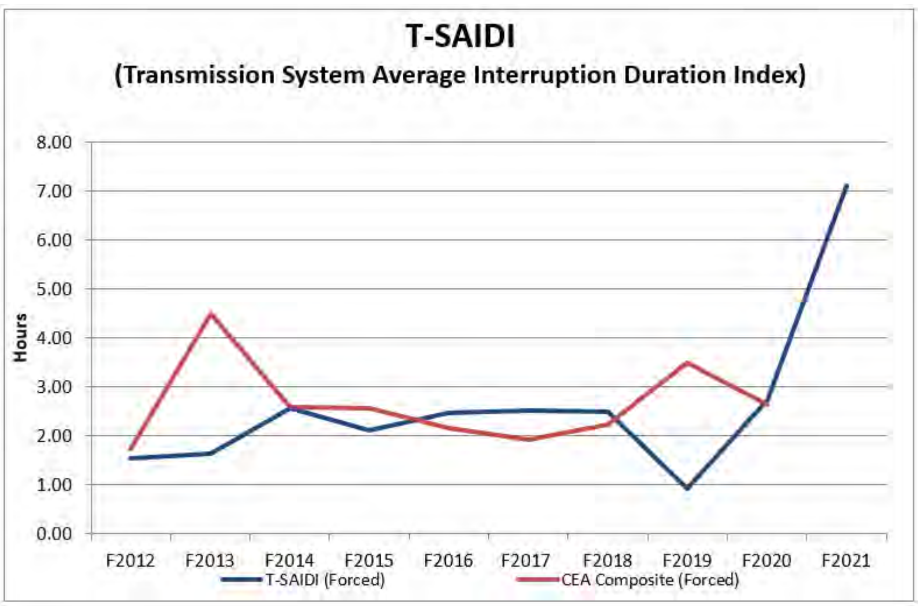

% ASAI
(Average Service Availability Index)
100.00
99.98
99.96
99.94
99.92
99.90
99.88
99.86
99.84
99.82
99.80
F2012 F2013 F2014 F2015 F2016 F2017 F2018 F2019 F2020 F2021
BCH Overall
CEA Overall
BCH (Distribution)
CEA (Distribution)

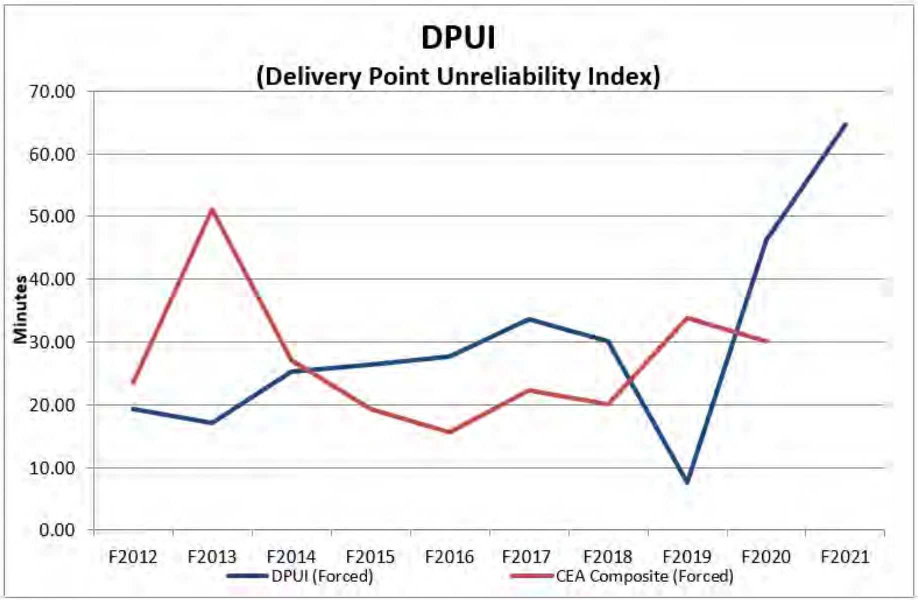


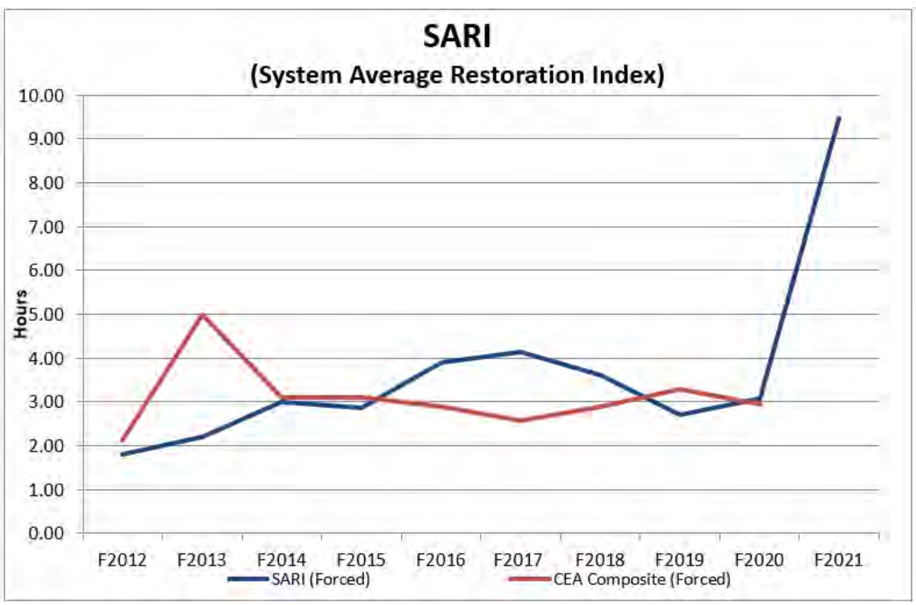
Note: The customer momentary interruptions and the resulting MAIFI may not apply to the utility's total customer population in the CEA comparison. Momentary outages are any interruptions on the feeders of less than one-minute duration, caused by disturbance on the distribution, substation or transmission system.

Transmission Graphs






DPUI
(Delivery Point Unreliability Index)
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Minutes
F2012
F2013
F2014
F2015
F2016
F2017
F2018
F2019
F2020
F2021
DPUI (Forced)
CEA Composite (Forced)


SARI
(System Average Restoration Index)
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Hours
F2012
F2013
F2014
F2015
F2016
F2017
F2018
F2019
F2020
F2021
SARI (Forced)
CEA Composite (Forced)

BC Hydro
Power smart

F05/F06 Revenue Requirements Application
Annual Response to Directive 26 of BCUC Decision

F2021 Annual Reporting of Reliability Indices

Attachment 2

Generation Reliability Indices

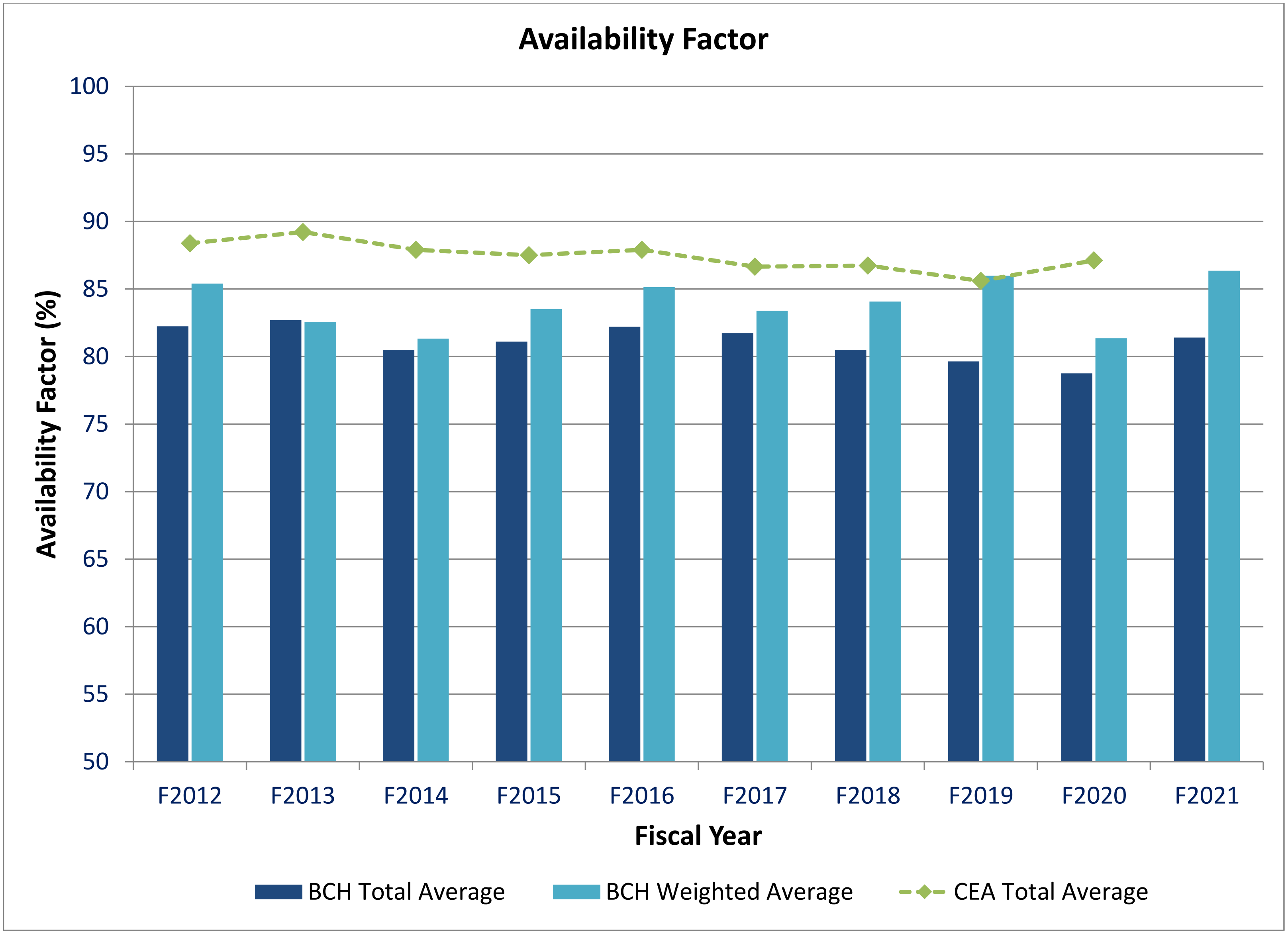
	BC Hydro Hydroelectric Units -Total Average					BC Hydro Hydroelectric Units - Weighted Average Note 6						CEA Hydroelectric Units -Total Average				
Fiscal Year	Average Availability Factor (%)	Average Operating Factor (%)	Average Forced Outage Count (Including starting failures) (Internal) Note 1	Average Forced Outage Factor (%) (Including starting failures) (Internal) Note 1	Failure Rate	Weighted Availability Factor (%)	Weighted Operating Factor (%)	Weighted Forced Outage Count (Including starting failures) (Internal) Note 1	Weighted FOF (%) (Including starting failures) (Internal) Note 1	Weighted Failure Rate	Calendar Year	Average Availability Factor (%)	Average Operating Factor (%)	Average Forced Outage Count (Including starting failures) (Internal) Note 1	Average Forced Outage Factor (%) (Including starting failures) (Internal) Note 1	Failure Rate
F2012	82.2	69.8	2.4	5.0	2.7	85.4	69.9	2.3	1.8	2.6	C2011	88.4	72.5	2.5	3.9	2.2
F2013	82.7	72.6	2.0	3.4	2.3	82.6	72.1	1.7	0.5	2.2	C2012	89.2	72.0	2.5	3.8	2.3
F2014 Note 2	80.5	64.7	2.5	4.7	2.7	81.3	65.8	2.3	1.7	2.6	C2013	87.9	74.0	2.4	3.9	2.1
F2015 Note 3	81.1	65.1	2.4	3.7	2.9	83.5	62.4	2.6	1.3	3.7	C2014	87.5	73.5	2.4	5.0	2.1
F2016 Note 3	82.2	65.9	2.0	4.1	2.4	85.1	66.7	1.8	2.6	2.3	C2015	87.9	70.4	3.2	4.7	2.1
F2017 Note 3	81.7	67.6	1.8	4.4	1.9	83.4	65.2	2.3	3.5	3.2	C2016	86.7	71.7	3.1	4.8	1.9
F2018 Note 3	80.5	65.5	1.7	2.6	2.0	84.1	66.0	1.8	0.7	2.4	C2017	86.7	73.0	3.3	4.9	2.2
F2019 Note 3	79.6	61.9	2.0	2.8	2.3	86.0	63.4	1.9	0.6	2.0	C2018	85.6	67.8	3.7	5.0	2.1
F2020 Note 4	78.8	59.1	2.0	4.3	2.3	81.4	61.3	1.8	1.6	2.1	C2019	87.1	70.8	3.3	3.7	1.9
F2021 Note 4	81.4	63.8	1.9	2.8	2.2	86.4	68.7	1.8	1.3	1.9	C2020	n/a	n/a	n/a	n/a	n/a

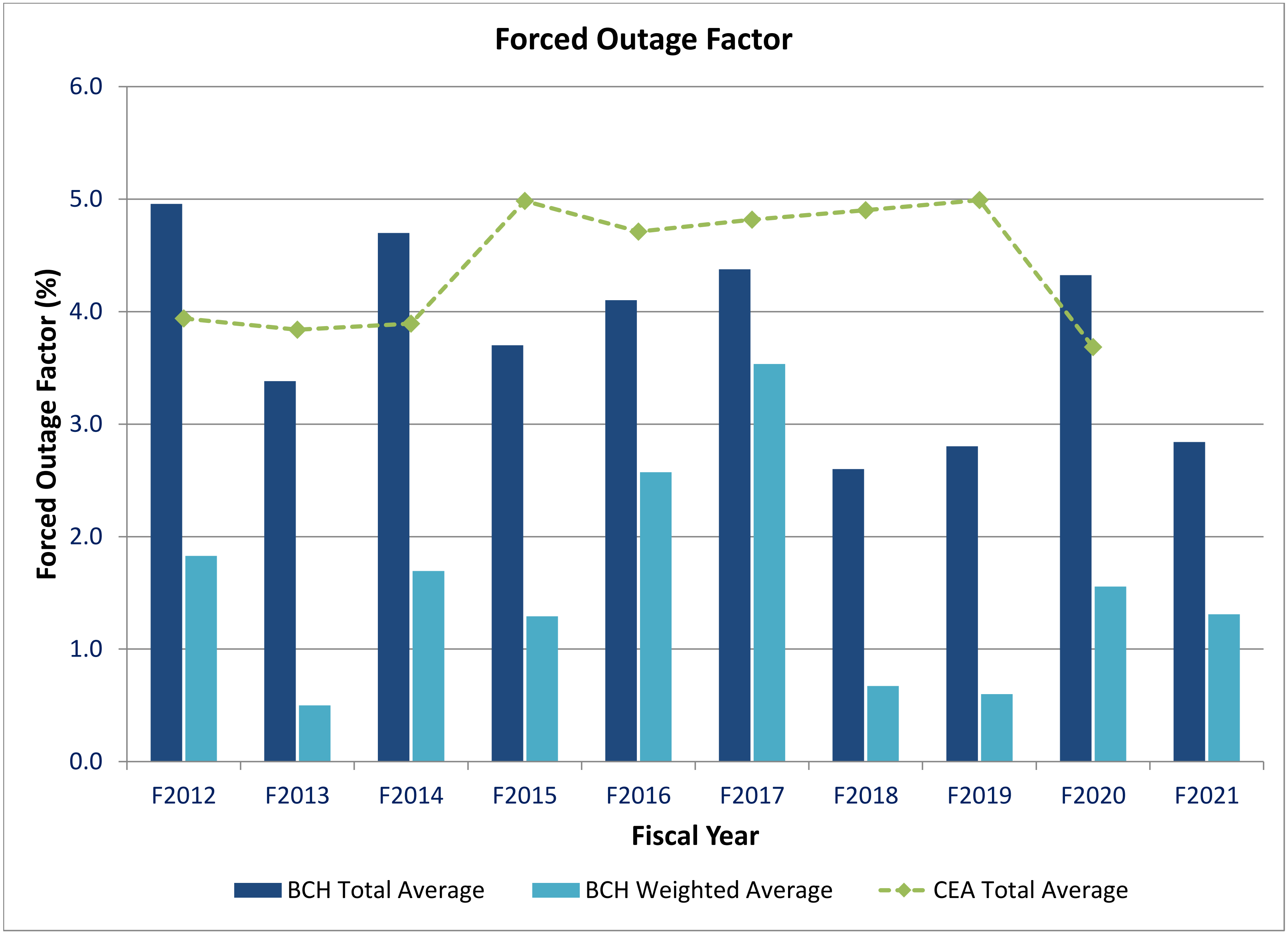
Definitions

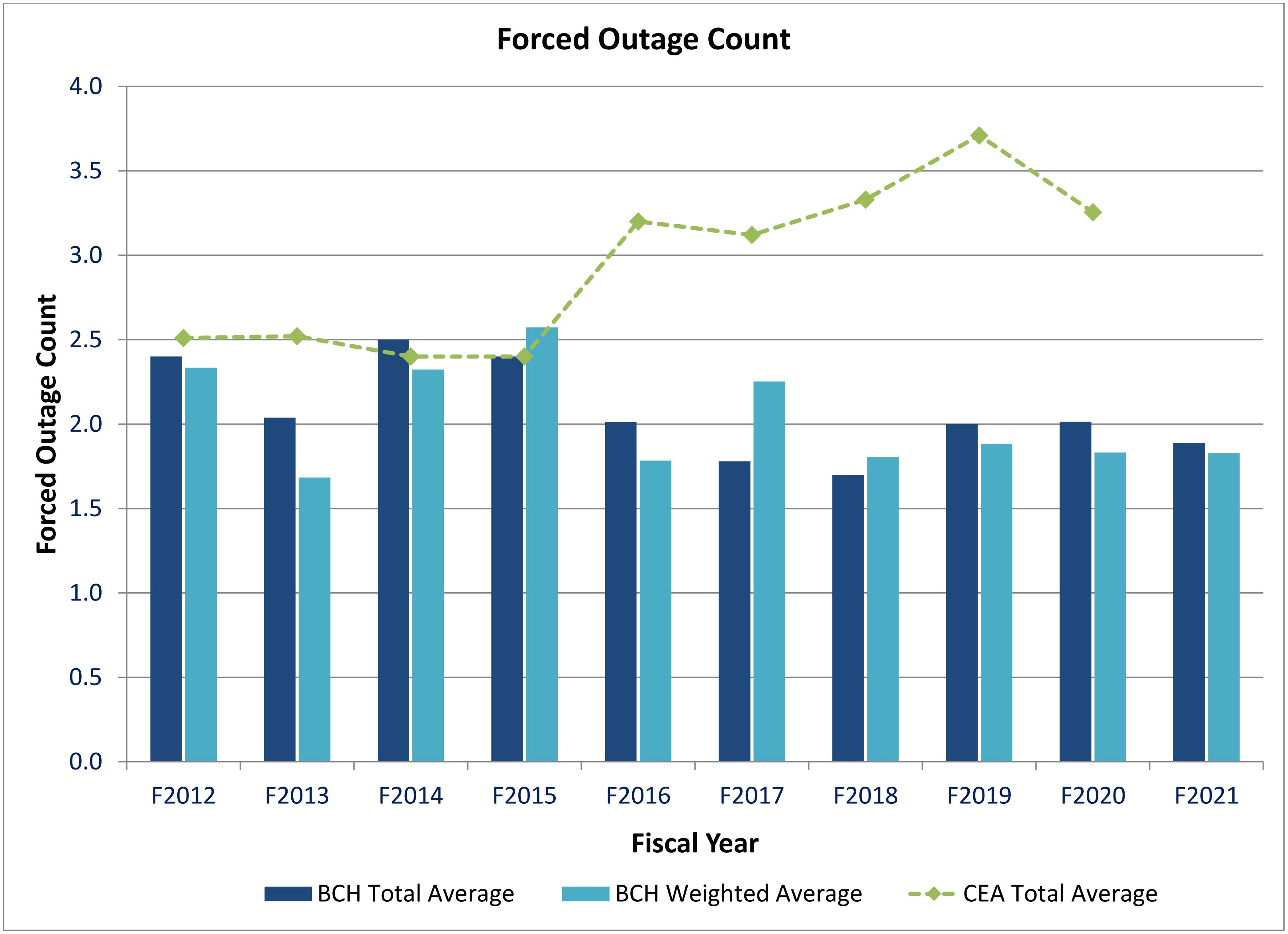
Availability Factor = Operating Time + Available-But-Not-Operating Time / In Commercial Service Time Note 5
Forced Outage Count = Average Number of Forced Outages / Unit / Year (including Starting Failures)(Internal)
Forced Outage Factor = Forced Outage Time (including Starting Failures)(Internal) / In Commercial Service Time Note 5
Failure Rate = Forced Outage Count (excluding Starting Failures)(Internal) / Operating Time X In Commercial Service Time Note 5

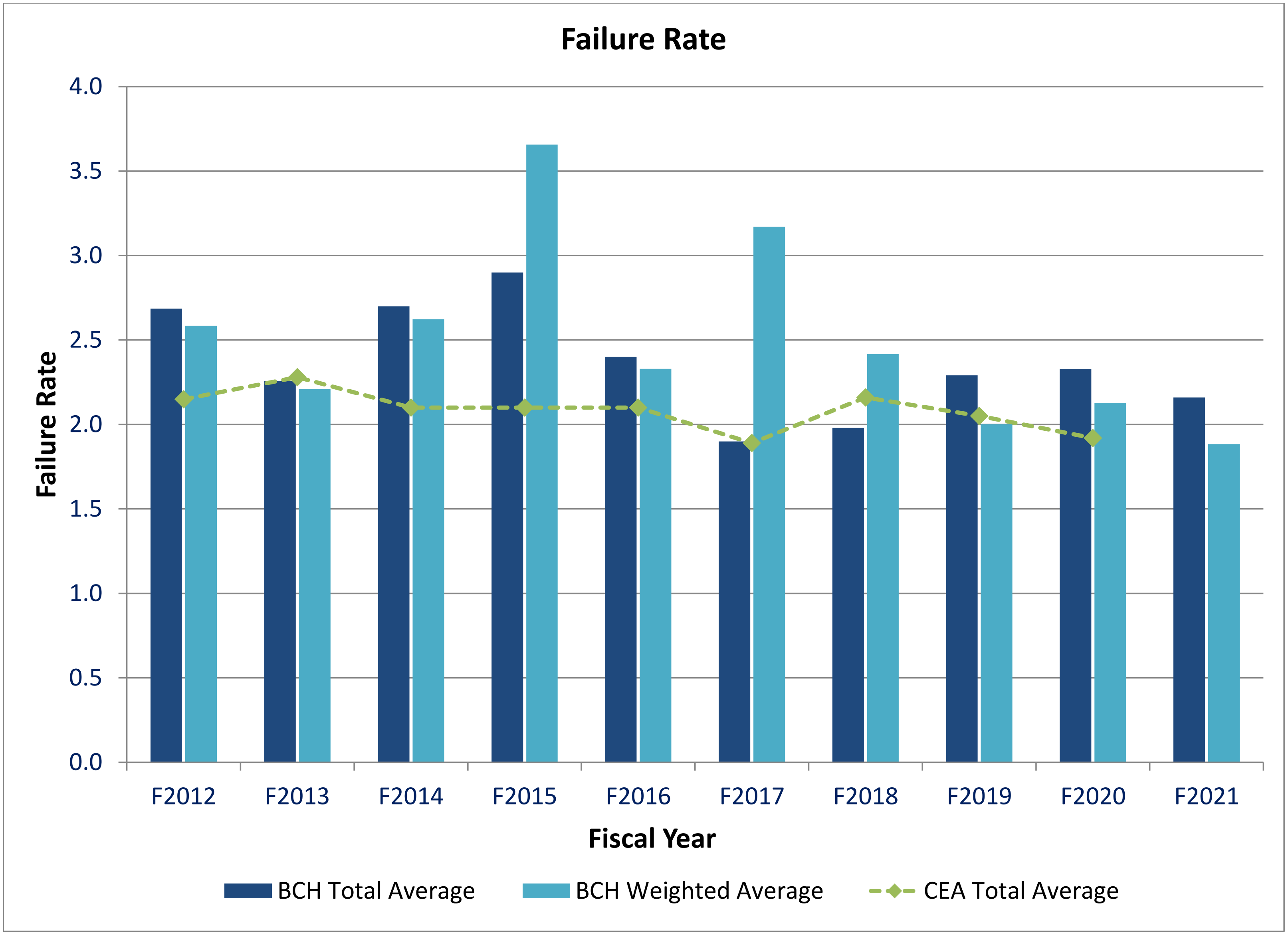
Notes

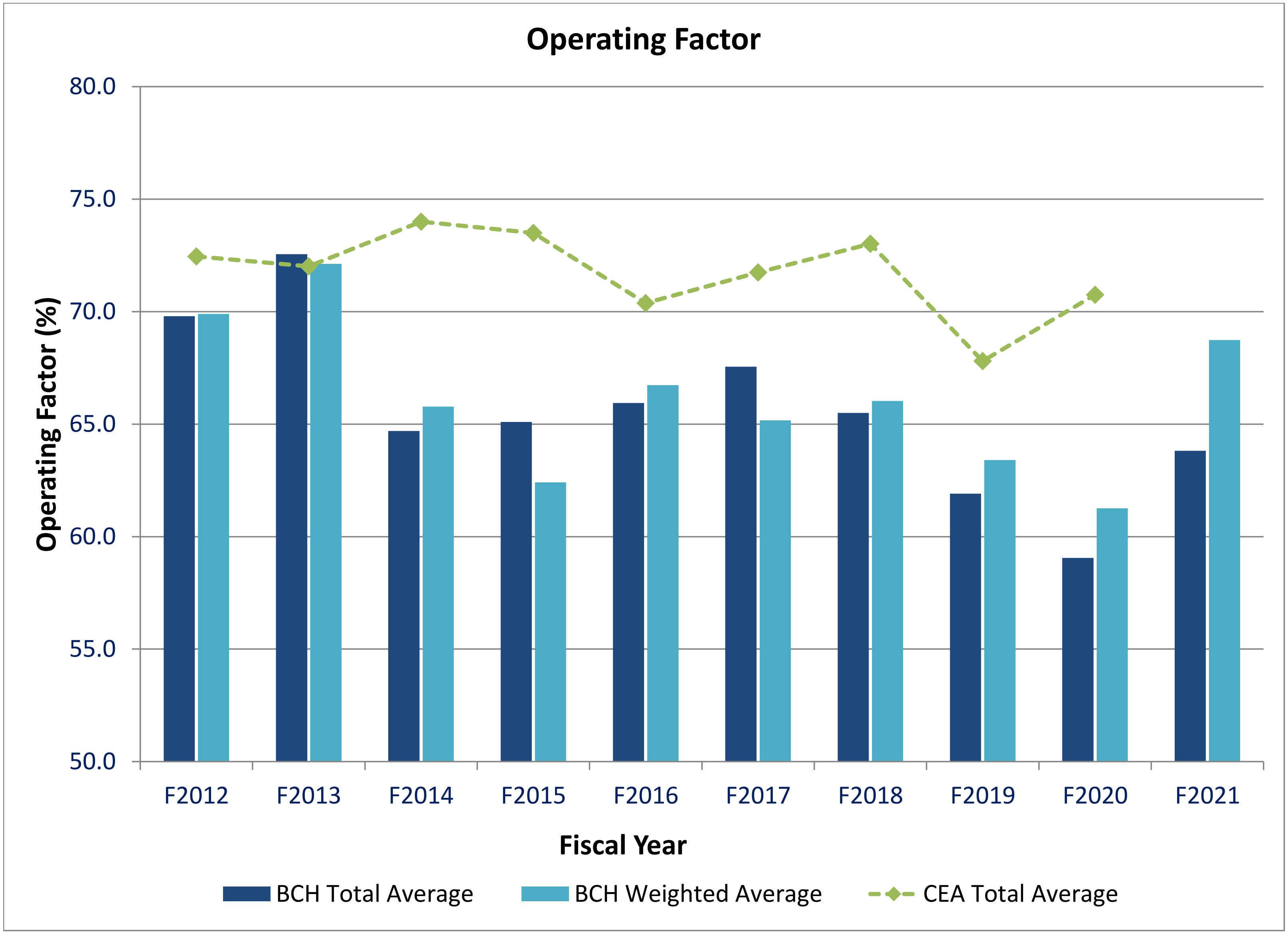
1. Outages with causes that were external to Generation, such as Transmission System forced outages, are excluded from this measure.
2. Data excludes ALU Unit 1 and SHU Unit 1, which have been forced out of service for an extended period.
3. Data excludes ALU Unit 1, SHU Unit 1 and ELK Units 1 and 2 which have been forced out of service for an extended period.
4. Data excludes ALU Unit 1, SHU Unit 1, ELK Units 1 and 2 and SPN Unit 1,2 and 3 which have been forced out of service for an extended period.
5. In Commercial Service Time represents the number of hours in the measurement period that the unit(s) were considered part of the active fleet.
6. Average reliability indices are weighted by unit maximum capacity rating.


Availability Factor
100
95
90
85
80
75
70
65
60
55
50
Availability Factor (%)
F2012
F2013
F2014
F2015
F2016
F2017
F2018
F2019
F2020
F2021
Fiscal Year
BCH Total Average
BCH Weighted Average
CEA Total Average


Forced Outage Factor
Forced Outage Factor (%)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
F2012
F2013
F2014
F2015
F2016
F2017
F2018
F2019
F2020
F2021
Fiscal Year
BCH Total Average
BCH Weighted Average
CEA Total Average


Forced Outage Count
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
Forced Outage Count
F2012
F2013
F2014
F2015
F2016
F2017
F2018
F2019
F2020
F2021
Fiscal Year
BCH Total Average
BCH Weighted Average
CEA Total Average


Failure Rate
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
Failure Rate
F2012
F2013
F2014
F2015
F2016
F2017
F2018
F2019
F2020
F2021
Fiscal Year
BCH Total Average
BCH Weighted Average
CEA Total Average


Operating Factor
80.0
75.0
70.0
65.0
60.0
55.0
50.0
Operating Factor (%)
F2012
F2013
F2014
F2015
F2016
F2017
F2018
F2019
F2020
F2021
Fiscal Year
BCH Total Average
BCH Weighted Average
CEA Total Average

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix R

Regulatory Accounts

Table of Contents

List of Tables

This appendix provides the following information regarding BC Hydro's regulatory accounts:

- The types of regulatory accounts and amortization periods;
- The application of interest to regulatory accounts; and
- A description of each regulatory account that existed and was approved by the BCUC prior to this application.

1 Types of Regulatory Accounts and Amortization Periods

The four types of regulatory accounts currently used by BC Hydro are consistent with the BCUC Regulatory Account Filing Checklist.[1] The four types of accounts are described below, including a discussion of the relevant considerations when determining the appropriate recovery mechanisms to ensure that the balances in the accounts are recovered over the appropriate time period. The alignment of the four account types to the BCUC Regulatory Account Filing Checklist is shown in the table below.

BC Hydro Account Type	BCUC Account Type
Variance accounts	Forecast variance account
Benefits matching accounts	Benefit matching account
Non-cash Provisions accounts	Other
IFRS Transition accounts	Retroactive expense accounts/Other

[1] https://www.bcuc.com/Documents/Guidelines/2017/05-03-2017_RegulatoryAccountFilingChecklist.pdf. Specifically, when requesting approval for a new regulatory account, the BCUC Regulatory Account Filing Checklist requires that regulated entities classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other and to identify if the regulatory account is a cash or non-cash account.

1.1 Variance Accounts

Regulatory accounts may be used to capture variances between forecast costs or revenues and actual costs or revenues. For BC Hydro, this includes variances between forecast and actual costs due to non-controllable factors such as water inflow levels, interest rates, discount rates, and market prices of energy, which are difficult to forecast. These types of variances are captured in BC Hydro's cash and non-cash variance accounts, which are discussed below.

BC Hydro believes that it should generally assume financial responsibility for controllable risks and create variance accounts for non-controllable risks. In the Fiscal 2005 to Fiscal 2006 Revenue Requirements Application (**RRA**), BC Hydro proposed the following criteria to assess whether a risk is controllable or non-controllable:[2]

1. BC Hydro's ability to directly or indirectly influence the cost category;
2. The volatility of the cost category;
3. The predictability of the cost category;
4. The materiality of the cost category to the revenue requirement; and
5. The frequency of major exceptions within the cost category.

In its Decision on the Fiscal 2005 to Fiscal 2006 RRA, the BCUC accepted BC Hydro's proposed criteria but concluded that risk/reward considerations were also a relevant consideration.[3]

BC Hydro is not proposing any changes in this application to the criteria used to assess whether a risk is controllable or non-controllable.

[2] BC Hydro Fiscal 2005 - Fiscal 2006 RRA Argument, page 70.
[3] BC Hydro Fiscal 2005 to Fiscal 2006 RRA Decision, pages 29 to 30.

BC Hydro's Cost of Energy Variance Accounts (i.e., Heritage Deferral Account, Non-Heritage Deferral Account, Load Variance Regulatory Account, Biomass Energy Program Regulatory Account, Low Carbon Fuel Credits Variance Regulatory Account and Trade Income Deferral Account) are examples of variance accounts that defer, for recovery or refund in a future period, differences between forecast and actual costs or revenues. The balances in these accounts are currently recovered through the DARR, which is discussed further in Chapter 7, section 7.3.3.3.

BC Hydro also has cash variance accounts that capture the difference between forecast and actual costs for non-energy related costs that BC Hydro considers to be non-controllable. Examples include the Storm Restoration Costs and the Total Finance Charges regulatory accounts. Amounts transferred to cash variance accounts in a test period are generally recovered over the next test period. This approach is appropriate as these accounts represent amounts already incurred, rather than amounts providing long-term benefits for ratepayers.

Lastly, BC Hydro has non-cash variance accounts that capture the differences between forecast and actual non-controllable costs which are non-cash in nature, for recovery from or refund to ratepayers in a future period. BC Hydro currently has four non-cash variance accounts: The Foreign Exchange Gains and Losses, the Non-Current Pension Costs, the PEB Current Pension Costs, and the Debt Management regulatory accounts. The recovery period for these variance accounts match the underlying attribute. For example, the Foreign Exchange Gains and Losses Regulatory Account is amortized on a straight-line pool basis over the weighted average life of the related debt and the Non-Current Pension Costs Regulatory Account is amortized over the expected average remaining service life of employees.

1.2 Benefit Matching Accounts

Regulatory accounts are often used to reflect timing differences between when a utility spends money to provide a service or acquire an asset, and when that expenditure provides benefits to ratepayers. The benefit of a particular service or asset may accrue to ratepayers over a long period of time. Regulatory accounts can be used to match the benefit with the cost, thereby supporting intergenerational equity between current and future ratepayers. The amortization period for this type of account will vary depending on the period of time that the benefit of a particular service or asset accrues to ratepayers. The use of this type of regulatory account means that BC Hydro's current customers are not required to pay for the full cost of an asset or service that will provide benefits to customers in the future.

The DSM Regulatory Account is an example of this type of account. Through DSM measures, BC Hydro spends money in current years to reduce the amount of electricity that customers would otherwise use in current and future periods. This results in lower energy costs and delayed or reduced infrastructure costs. The benefits of reduced costs from these DSM measures accrue to future customers. Therefore, the costs of DSM measures are matched to the benefits realized by future customers. DSM costs are deferred and amortized over 15 years, which reflects the average measure life of DSM measures.

The Site C Regulatory Account is another example of this type of regulatory account. This account defers costs attributable to the project that are not eligible for capitalization related to the Site C Project to future years. The Site C Project has a long development period before it will be placed into service and provide benefits to customers. If these costs had been expensed as incurred, it would have created unfair rate impacts on current ratepayers, prior to the benefits of the project being provided.

1.3 Non-Cash Provisions

Non-cash provisions are regulatory accounts set up in response to loss provision liabilities required under IFRS accounting rules. These provisions are not recovered in rates until actual cash expenditures are made against the provision. At that time, the provision is drawn down by the amount of the expenditure and a corresponding amount is transferred to the matching regulatory account. This amount is then amortized into rates based on the approved amortization method. The provision regulatory accounts remain in place until the loss provision liability is no longer required under IFRS. These accounts are regulatory assets which, subject to BCUC approval, preserve BC Hydro's ability to collect, in rates, any actual amounts paid in respect of these provisions. BC Hydro currently has two non-cash provision regulatory accounts: The First Nations Provisions and the Environmental Provisions regulatory accounts.

1.4 IFRS Transition Accounts

A change in the accounting standards applicable to BC Hydro may create non-controllable financial impacts, requiring a regulatory account to protect customers from sudden and significant rate increases.

In fiscal 2013, BC Hydro transitioned to the Prescribed Standards directed by the Government of B.C.'s Treasury Board. The Prescribed Standards were based on the principles of IFRS, combined with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, *Regulated Operations* with one modification. This change impacted the method of accounting for capital overheads. It also required BC Hydro to recognize, on its balance sheet, all unamortized actuarial gains and losses on its pension and other post-employment benefit plans. To recover the financial impact of these changes from customers over a reasonable time period, BC Hydro proposed the establishment of the IFRS Transition regulatory accounts. If BC Hydro had recognized the impact of the transition to IFRS in its rates at the time of the transition, the rate impact for customers in the year of transition, would have been significant.

The approved recovery periods for the IFRS Transition Accounts are 20 years for the IFRS Pension Regulatory Account and 40 years for the IFRS Property, Plant and Equipment Regulatory Account. These recovery periods mean that the accounts recover the transition costs of pension and capital assets over the same period of time as if the IFRS rules had not come into place as part of the Prescribed Standards.

1.5 Summary of Recovery Mechanisms

Table R-1 below provides a summary of the rationale to determine the appropriate recovery mechanisms for BC Hydro's regulatory accounts.

Table R-1 Summary of Rationale for Regulatory Account Recovery Mechanisms

Type of Regulatory Account	Rationale for Recovery Mechanism
Variance Accounts:	
Cost of Energy Variance Accounts	BC Hydro is proposing to continue the use of The Deferral Account Rate Rider mechanism which minimizes intergenerational inequity by being responsive to the changing net balance in the cost of energy variance accounts, while maintaining rate stability for customers to the extent practicable. BC Hydro is proposing to increase the Deferral Account Rate Rider from 0 per cent to (2.0) per cent on April 1, 2023, (1.0) per cent on April 1, 2024 and (0.5) per cent on April 1, 2025 to refund the forecast fiscal 2022, fiscal 2023 and fiscal 2024 net closing balances, in the Cost of Energy Variance Accounts over fiscal 2023, fiscal 2024 and fiscal 2025, respectively.
Other Cash Variance Accounts	To minimize intergenerational inequity, cash variance accounts should be recovered in the subsequent test period.
Non-Cash Variance Accounts	Non-cash variances should be recovered over the remaining period of the associated asset or liability (e.g., expected average remaining service life of employees or remaining term of debt issuances).
Benefit Matching Accounts	To achieve intergenerational equity, the recovery period should match the future benefit period of the expenditure.
Non-Cash Provisions	Since non-cash provisions are not recovered in rates, no recovery mechanism is required. The provision is drawn down when actual expenditures are incurred, at which time the amounts are transferred to the corresponding regulatory account and recovered via the approval mechanism for those accounts.
IFRS Transition Accounts	To smooth the impact of changes in accounting standards, the balances in these accounts should be recovered on the same basis as they would have been recovered under the previous accounting rules.

BC Hydro has BCUC-approved or has requested recovery mechanisms to collect, in rates, the balances of all of its regulatory accounts except the portion of the Customer Crisis Fund Regulatory Account described in Chapter 7 section 7.3.3. and the portion of the Mining Customer Payment Plan Regulatory Account balance attributable to the MCPP impairment losses as described in Chapter 7, section 7.3.3.6.

2 Application of Interest to Regulatory Accounts

This section explains that it is generally appropriate for regulatory account balances to attract interest at BC Hydro's weighted average cost of debt in recognition that BC Hydro incurs carrying costs.

2.1 Rationale for Application of Interest Charge to Regulatory Account Balances

BC Hydro applies the principle of matching costs with benefits to determine whether interest should be applied to a regulatory account balance. This reflects the fact that the carrying costs of maintaining the account balances may have a real financial cost in any particular period that should be recovered in rates. For cash variance regulatory accounts that arise from a direct cash outlay by BC Hydro, the related interest costs are generally included as part of the regulatory accounts. BC Hydro incurs financing charges to carry amounts that were paid in cash but not recovered in rates in the same test period. For some accounts, the interest cost may be immediately expensed from the regulatory account to rates, rather than being deferred and amortized for recovery in future rates. For interest applicable accounts, interest is applied to the account balance regardless of whether the account represents an amount owing to or from ratepayers. In other words, ratepayers receive an interest benefit in accounts containing an amount owing to them.

Variance regulatory accounts such as energy deferral accounts also attract interest because BC Hydro does not forecast variances in the accounts and therefore must fund the variances. In the case of lower than forecast revenues, BC Hydro incurs debt which results in finance charges.

Interest applied to regulatory accounts does not have the effect of increasing or decreasing BC Hydro's allowed net income, as the interest added to regulatory accounts is intended to offset the unbudgeted incremental interest costs that BC Hydro has incurred.

Based on these criteria, and in accordance with BCUC Orders, BC Hydro applies interest to all regulatory accounts, with the exception of the following accounts:

(a) Non-cash regulatory accounts (such as provisions);

(b) The Total Finance Charges Regulatory Account (since interest costs are part of total finance charges); and

(c) Regulatory accounts that capture timing differences (such as Pre-1996 Contributions).

In addition, interest is not charged to the DSM Regulatory Account, similar to the treatment for capital projects, as DSM expenditures generally go into service in the year of expenditure and BC Hydro does not apply interest on capital projects after they enter service. Table R-2 below indicates which deferral and regulatory accounts have interest applied to balances in accordance with BCUC orders.

Table R-2 Application of Interest to Regulatory Accounts

	Regulatory Account	Interest Applied to Balance
Cost of Energy Variance Accounts		
1	Heritage Deferral Account	Yes
2	Non Heritage Deferral Account	Yes
3	Trade Income Deferral Account	Yes
4	Load Variance Account	Yes
5	Biomass Energy Program Account	Yes
6	Low Carbon Fuel Credits Variance Regulatory Account	Yes

	Regulatory Account	Interest Applied to Balance
Other Cash Variance Accounts		
7	Storm Restoration Costs Regulatory Account	Yes
8	Amortization of Capital Additions Regulatory Account	Yes
9	Total Finance Charges Regulatory Account	No
10	Remediation Regulatory Account	Yes
11	Real Property Sales Regulatory Account	Yes
12	Dismantling Cost Regulatory Account	Yes
13	Customer Crisis Fund Regulatory Account	Yes
14	Mining Customer Payment Plan Regulatory Account	Yes
15	Project Write-off Costs Regulatory Account	Yes
16	Electric Vehicle Costs Regulatory Account	Yes
17	MRS Costs Regulatory Account	Yes
18	Fiscal 2022 Depreciation Study Impact	Yes
Non-Cash Variance Accounts		
19	Foreign Exchange Gains and Losses Regulatory Account	No
20	Non-Current Pension Costs Regulatory Account	No
21	PEB Current Pension Costs Regulatory Account	No
22	Debt Management Regulatory Account	No
Benefit Matching Accounts		
23	DSM Regulatory Account	No
24	First Nations Costs Regulatory Account	Yes
25	Site C Regulatory Account	Yes
26	Pre-1996 Contributions in Aid of Construction Regulatory Account	No
27	SMI Regulatory Account	Yes
28	Load Attraction Costs Regulatory Account	Yes
Non-Cash Provisions		
29	First Nations Provisions Regulatory Account	No
30	Environmental Provisions Regulatory Account	No

	Regulatory Account	Interest Applied to Balance
IFRS Transition Accounts		
31	IFRS Property, Plant and Equipment Regulatory Account	No
32	IFRS Pension Regulatory Account	No

The table above no longer includes the Rock Bay Regulatory Account as the BCUC approved the closure of the account effective, March 31, 2021. At March 31, 2021, the account held a credit balance of $0.15 million related to interest. BC Hydro transferred the balance to the Total Finances Charges Regulatory Account, and it will be refunded to ratepayers in the Test Period.

2.2 Interest Rate Applied to Regulatory Accounts

By Order No. G-77-12A to BC Hydro's Fiscal 2012 to Fiscal 2014 Amended RRA, the BCUC approved that the interest rate applicable to BC Hydro's regulatory account balances in a given year is the weighted average cost of debt in that year. The weighted average cost of debt that is forecast to be applied to the regulatory account balances is 3.01 per cent for fiscal 2023, 2.98 per cent for fiscal 2024 and 3.11 per cent for fiscal 2025.

3 Previously Approved Regulatory Accounts

Consistent with prior applications, provided below is an overview of the history and recovery periods of all BC Hydro's currently approved regulatory accounts. The descriptions reflect approvals prior to the requests for changes in this application.

3.1 Cost of Energy Variance Accounts

BC Hydro has six Cost of Energy Variance Accounts that capture the differences between forecast and actual revenues and costs for recovery or refund to ratepayers in future periods: the Heritage Deferral Account, the Non Heritage Deferral Account, the Load Variance Regulatory Account, the Biomass Energy Program Variance Regulatory Account, the Trade Income Deferral Account and the Low Carbon Fuel Credits Regulatory Account.

The Heritage Deferral Account and Trade Income Deferral Account were created pursuant to Heritage Special Direction No. HC2 and BCUC Order No. G-96-04. Special Direction No. HC2 was repealed in March 2014 and the Heritage Deferral Account and the Trade Income Deferral Account were continued on an ongoing basis through Direction No. 7 and BCUC Order No. G-48-14.

By Order No. G-96-04, the BCUC also approved the establishment of the Non-Heritage Deferral Account and approved the specific cost components eligible for deferral to the Heritage Deferral Account and to the Non-Heritage Deferral Account. Through subsequent Orders, the scope of the Non-Heritage Deferral Account has been expanded.[4] Notably, by Order No. G-16-09, the BCUC authorized BC Hydro to defer to the Non-Heritage Deferral Account, the variances between forecast and actual cost of energy arising from differences in forecast and actual domestic customer load in fiscal 2009 and fiscal 2010. This was continued through the Fiscal 2011 Negotiated Settlement Agreement and by Order No. G-77-12A to the

[4] BCUC Order No. G-16-11 approved the deferral of variances between forecast and actual transmission service revenue and non-capital emergency transmission maintenance expenditures over $1 million to the Non-Heritage Deferral Account.
BCUC Order No. G-68-17 approved the deferral of variances between forecast and actual Northwest Transmission Line Supplemental Charge revenues to the Non-Heritage Deferral Account.
BCUC Order No. G-130-18 approved the deferral of the fiscal 2019 Lease revenues arising from the Waneta 2017 Transaction and the revenue associated with capital expenditures made by Teck with respect to Teck's two-third interest in Waneta during the Lease Term to the Non-Heritage Deferral Account. The Order also approved that the variance between forecast and actual water rentals in a given year arising from the Waneta 2017 transaction be excluded from the water rental variances that are currently deferred to the Non-Heritage Deferral Account during the Lease Term.

Fiscal 2012 to Fiscal 2014 RRA. Direction No. 7 required the BCUC to allow these variances to be deferred to the Non-Heritage Deferral Account on an ongoing basis. Direction No. 7 also required the BCUC to allow BC Hydro to defer costs associated with the decommissioning of portions of Burrard Thermal not required for transmission support services, to the Non-Heritage Deferral Account.

In its Decision on the Fiscal 2020 to Fiscal 2021 RRA, the BCUC directed the following:

- The creations of two additional Cost of Energy Regulatory Accounts:
  - Load Variance Regulatory Account, to capture variances between forecast and actual domestic customer load (referred to as the Domestic Revenue Variance, which was previously captured in the Non-Heritage Deferral Account);[5] and
  - Biomass Energy Program Variance Regulatory Account, to capture all variances between forecast and actual amounts related to the Biomass Energy Program.[6]
- Deferral of any variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing BCUC orders, to the Non-Heritage Deferral Account.[7]

The new regulatory accounts allow for the separation of certain components of BC Hydro's existing Cost of Energy Variance Accounts for enhanced transparency.

5 BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), Directive 15.

6 BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), Directive 38.

7 BCUC Decision and Order No. G 247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), Directive 44.

Order No. G-127-21 approved the 2020 Transfer Pricing Agreement (**2020 TPA**) as filed by BC Hydro. The adoption of the 2020 TPA resulted in a change in the presentation of transactions relative to the terms used in BCUC Order No. G-96-04.[8] The terms from Order No. G-96-04, “Market Electricity Purchases”, “Surplus Sales” and “Net Purchases (Sales) From Powerex” were replaced by “System Exports” and “System Imports” under the 2020 TPA and variances on these items are deferred to the Non-Heritage Deferral Account.

By Order No. G-248-21, the BCUC approved the establishment of the Low Carbon Fuel Credits Regulatory Account to capture, on an ongoing basis, the difference between forecast and actual miscellaneous revenue from low carbon fuel credits, and apply interest on the balance of the account based on BC Hydro’s current weighted average cost of debt. As the low carbon fuel credit revenues recognized by BC Hydro are a result of transfers to Powerex based on a transfer pricing agreement, low carbon fuel credit variances experienced by BC Hydro are offset by variances in Trade Income. Trade Income variances are deferred to the Trade Income Deferral Account. BC Hydro has proposed in this application to classify the Low Carbon Fuel Credits Regulatory Account as a Cost of Energy variance account and recover the Low Carbon Fuel Credits Regulatory Account balance using the DARR mechanism.

The purpose of the six Cost of Energy Variance Accounts is to defer the differences between forecast and actual revenues and energy costs for recovery or refund to ratepayers in future periods. These differences are non-controllable and can be

[8] In accordance with BCUC Order No. G-96-04, Directive 11, BC Hydro deferred variances between forecast and actual Market Electricity Purchases and Surplus Sales to the Heritage Deferral Account, and in accordance with BCUC Order No. G-96-04, Directive 12, BC Hydro deferred variances between forecast and actual Net Purchases (Sales) from/to Powerex to the Non-Heritage Deferral Account. The scope of variances covered by these existing orders is equivalent to the variances between forecast and actual System Exports and System Imports.

positive or negative. The variances captured by the Cost of Energy Variance Accounts can be summarized as follows:

- The Heritage Deferral Account captures variances between the forecast and actual cost of Heritage Energy as described in Chapter 4, sections 4.5. and Domestic Transmission - Export costs as described in Chapter 4, section 4.7.2. In addition, the Heritage Deferral Account captures variances between forecast and actual costs and revenues for items approved by BCUC Order No. G-96-04, which includes Skagit Valley Treaty revenues;
- The Non-Heritage Deferral Account captures variances between the forecast and actual cost of Non-Heritage Energy which includes IPPs and Long-Term Commitments as described in Chapter 4, section 4.6.1, Non-Integrated Areas in Chapter 4, section 4.6.2, Gas and Other transportation costs in Chapter 4, section 4.6.3, System Exports which consists of sales of electricity to Powerex by BC Hydro, and System Imports which consists of purchases of electricity by BC Hydro from Powerex and thermal generation run for Powerex as described in Chapter 4, section 4.7.1. In addition, the Non-Heritage Deferral Account captures variances between forecast and actual costs for items approved by BCUC Order No. G-96-04 and subsequent Orders as noted above;
- The Load Variance Regulatory Account captures variances between forecast and actual domestic customer load;
- The Biomass Energy Program Variance Regulatory Account captures all variances between forecast and actual amounts related to the Biomass Energy Program;
- The Trade Income Deferral Account captures variances between the forecast and actual Trade Income as described in Chapter 8, section 8.10; and

- The Low Carbon Fuel Credits Regulatory Account captures the difference between forecast and actual miscellaneous revenue from low carbon fuel credits.

In its Decision on the Previous Application, Directive 14,[9] the BCUC approved the recovery of the balances in the Cost of Energy Variance Accounts using the DARR based on the DARR table mechanism and the forecast net balance of the Cost of Energy Variance Accounts at the end of the preceding fiscal year, for fiscal 2022 only.

BC Hydro is not requesting any changes to the scope of the existing Cost of Energy Variance Accounts in this application but is requesting the continued use of the DARR recovery mechanism in this application in Chapter 7.

3.2 Storm Restoration Costs Regulatory Account

By Order No. G-16-09 to the Fiscal 2009 to Fiscal 2010 RRA, the BCUC approved the ongoing deferral of the difference between actual storm related restoration costs and the average of the actual storm restoration costs for the five most recent normal weather years. Fiscal 2017 through fiscal 2021 comprise the five most recent normal weather years and result in an average annual storm restoration cost of $19.2 million. BC Hydro has included this amount for storm restoration costs in its fiscal 2023 to fiscal 2025 operating cost plan.

In many recent years, BC Hydro has experienced more extreme weather resulting in volatile storm-related expenditures, which has caused the storm expenditures to vary as shown in Table R-3 below.

9 BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), Directive 14.

Table R-3 Storm Restoration Costs Fiscal 2017 to Fiscal 2021 Actual

	($ million)	F2017 Actual	F018 Actual	F2019 Actual	F2020 Actual	F2021 Actual	F2017-F2021 Average
		1	2	3	4	5	6
1	Storm Restoration Costs	25.3	22.9	25.6	10.1	12.1	19.2

By Order No. G-47-18, the BCUC approved that interest continue to be applied to the balance of this regulatory account and that the forecast account balance at the end of a test period be recovered over the next test period. Interest is applied to the account based on BC Hydro's weighted average cost of debt and forecast interest is recovered from the account each year. By Order No. G-215-20, the BCUC approved BC Hydro's request to expand the scope of the Storm Restoration Costs Regulatory Account to include the deferral of revenue impacts related to BC Hydro's actual amounts for bill credits and waivers of charges for evacuation relief.

BC Hydro is not requesting any changes to this account in this application.

3.3 Amortization of Capital Additions Regulatory account

By Order No. G-16-09, the BCUC directed BC Hydro to defer to a regulatory account any differences between forecast and actual amortization of capital additions. In its Decision, the BCUC stated that:

> "the most effective solution to ensuring that amortization charges collected in revenue requirements for the test period appropriately reflect the capital assets that are actually utilized for the benefit of ratepayers during the same test period is to establish a new regulatory account."[10]

The Amortization of Capital Additions Regulatory Account was continued in the Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement,

[10] Fiscal 2009 to Fiscal 2010 Revenue Requirement Application Decision, page 191.

the Fiscal 2012 to Fiscal 2014 Amended RRA and the Fiscal 2015 to Fiscal 2016 Revenue Requirements Rate Application. By Order No. G-47-18, the BCUC approved this regulatory account to continue on an ongoing basis, that interest continue to be applied to the balance of this regulatory account, and that the forecast account balance at the end of a test period be recovered over the next test period. Interest is applied to the account based on BC Hydro's weighted average cost of debt and forecast interest is recovered from the account each year.

BC Hydro is not requesting any change to this regulatory account in this application.

3.4 Fiscal 2022 Depreciation Study Impact Regulatory Account

In its decision on the Previous Application, Directive 15,[11] the BCUC directed BC Hydro to establish a new regulatory account to capture the variances arising in fiscal 2022 as a result of any changes to the depreciation expense determined in the depreciation study. Interest charges are applied to this account based on BC Hydro's weighted average cost of debt. As directed by the BCUC, BC Hydro is requesting a recovery mechanism for the account in Chapter 7 of this application.

3.5 Total Finance Charges Regulatory Account

By Order No. G-16-09 to the Fiscal 2009 to Fiscal 2010 RRA, the BCUC directed BC Hydro to defer to a regulatory account any differences between forecast and actual finance charges for fiscal 2009 and fiscal 2010. The Total Finance Charges Regulatory Account was continued by BCUC decisions on the Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement, the Fiscal 2012 to Fiscal 2014 Amended RRA and the Fiscal 2015 to Fiscal 2016 Revenue Requirements Rate Application. By Order No. G-47-18, the BCUC approved the continuation of this regulatory account on an ongoing basis, and that

[11] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), Directive 15.

the forecast account balance at the end of a test period be recovered over the next test period.

BC Hydro is not requesting any changes to this account in this application.

3.6 Remediation Regulatory Account

Starting in fiscal 2013 and in following years, BC Hydro began to incur expenditures related to asbestos remediation at its facilities. By Order No. G-7-13, the BCUC approved the establishment of the Asbestos Remediation Regulatory Account for unplanned asbestos remediation costs in fiscal 2013 and fiscal 2014. In accordance with Direction No. 7, BCUC Order No. G-48-14 authorized BC Hydro to continue to defer variances between forecast and actual asbestos remediation costs, to the account, on an ongoing basis.

By Order No. G-47-18, the BCUC approved an expansion of the account scope to include costs incurred related to the compliance with polychlorinated biphenyl regulations. To reflect this change, the BCUC also approved that the name of the account be changed to the Remediation Regulatory Account.

By Order No. G-47-18, the BCUC approved, starting in fiscal 2017, and on an ongoing basis, that actual expenditures related to compliance with polychlorinated biphenyl regulations and asbestos remediation be deferred to this account each year, and forecast expenditures related to compliance polychlorinated biphenyl regulations and asbestos remediation be amortized from this account each year. Order No. G-47-18 also approved that interest continue to be applied to the balances in the account and that the forecast account balance at the end of a test period be recovered over the next test period. Interest is applied to the account based on BC Hydro’s weighted average cost of debt and forecast interest is recovered from the account each year.

It continues to be appropriate to defer variances related to asbestos remediation to the Remediation Regulatory Account. The rationale for deferring these variances is the same as the rationale accepted by the BCUC for the deferral of variances related to compliance with polychlorinated biphenyl regulations. In its Decision to the Fiscal 2017 to Fiscal 2019 RRA, the BCUC stated that:

> *"Although the treatment of PCB is not prescribed by Direction No. 7, as it is for asbestos costs, the Panel concurs with BC Hydro that PCB costs are similar in nature to asbestos costs in that they involve long-term estimates, the actual expenditures are susceptible to variances in amount and timing and differences from forecast due to the timing and scope of work undertaken. Furthermore, the Panel finds the consistent treatment of asbestos and PCB costs is reasonable."*[12]

BC Hydro is not requesting any changes to this account in this application.

3.7 Real Property Sales Account

By Order No. G-48-14, the Real Property Sales Regulatory Account was established to defer the variances between BC Hydro's actual and forecast real property gain/loss from real estate sales, with interest to be applied to the account based on BC Hydro's weighted average cost of debt.

The timing of completion of real estate transactions is difficult to forecast accurately. Since fiscal 2015, BC Hydro has been preparing surplus properties for sale. Activities have included market value appraisals and estimates, investigation and remediation of environmental contamination, working with municipalities on subdivision requirements, and consultation with First Nations.

The 2013 10 Year Rates Plan included a target of $50 million of net gains from real property sales from fiscal 2015 to fiscal 2019. Consistent with this target, BC Hydro included $10 million in forecast net gains from real property sales in each fiscal year

[12] BCUC Order No. G-47-18, Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, page 65.

in both the Fiscal 2015 to Fiscal 2016 Revenue Requirements Rate Application and the Fiscal 2017 to Fiscal 2019 RRA.

BC Hydro increased its net gains target from $50 million to $100 million and extended the timeframe to achieve this target to the end of fiscal 2024. However, in Directive 41[13] of its Decision on BC Hydro's Fiscal 2020 to Fiscal 2021 RRA, Order No. G-246-20, the BCUC disallowed BC Hydro's forecast of $10 million net gains in each of fiscal 2020 and fiscal 2021 and instead approved forecast net gains of $0 in that test period from the sale of surplus real property. The future recovery of this account is addressed in Chapter 7 of the Application.

BC Hydro is not requesting any changes to this account in this application.

3.8 Dismantling Cost Variance Account

The Dismantling Cost Regulatory Account was established by BCUC Order No. G-47-18 and captures variances between forecast and actual dismantling costs.

In its Decision on the Fiscal 2017 to Fiscal 2019 RRA, the BCUC approved the use of this account for the fiscal 2017 to fiscal 2019 test period. In its Decision on the Fiscal 2020 to Fiscal 20021 RRA, the BCUC approved the use of this account for the fiscal 2020 to fiscal 2021 test period. In its Decision, the BCUC stated:

> "The Panel accepts that dismantling costs are largely driven by the capital plan and are impacted by capital project schedules. Given this and the magnitude of the variances in the last test period, the Panel agrees that variances between forecast and actual dismantling costs should be provided deferral treatment similar to the treatment of variances between forecast and actual amortization of capital asset additions."

[13] Directive 41; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 127.

In its Decision on the Previous Application, Directive 16,[14] the BCUC approved the use of this account for fiscal 2022. In response to BCUC Order No. G-246-20, Directive 40,[15] on the Fiscal 2020 to Fiscal 2021 RRA, BC Hydro is requesting the continued use of this account for fiscal 2023 to fiscal 2025 and proposing to adopt net salvage rates using a transition approach, beginning in the next test period, in Chapter 7 and Chapter 8 of this application.

3.9 Customer Crisis Fund Regulatory Account

By Order No. G-166-17, the BCUC approved the establishment of the Customer Crisis Fund (**CCF**) Regulatory Account.

By Order No. G-5-17 to the 2015 Rate Design Application, the BCUC directed BC Hydro to file a proposal for the establishment of a crisis intervention fund pilot program (**CCF Pilot Program**) for residential customers who have arrears with BC Hydro and are unable to pay their electricity bills. By Order No. G-166-17, the BCUC approved the CCF Pilot Program on a three-year basis.

The costs related to the CCF Pilot Program were driven by program participation and thus varied from forecast. In addition, there were variations in the timing of revenues and costs over the duration of the CCF Pilot Program.

Accordingly, in its application to establish the CCF Pilot Program, BC Hydro proposed that the net difference between the revenues collected under the CCF Rate Rider and the incremental costs related to the CCF Pilot Program in each fiscal year be transferred to the CCF Regulatory Account. Any remaining balance in the CCF Regulatory Account at the end of the CCF Pilot Program would be to the account of residential ratepayers.

---

[14] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021) Directive 16.

[15] Directive 40; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020).

By Decision and accompanying Order No. G-144-21 dated May 7, 2021, the BCUC found that continuation of the CCF Pilot Program could not be justified and ordered BC Hydro to terminate the CCF Pilot Program effective May 31, 2021. By Order No. G-162-21 dated May 27, 2021, the BCUC approved BC Hydro's application to rescind the CCF Rate Rider, effective June 1, 2021. By Order No. G-179-21A dated June 7, 2021, the BCUC granted approval allowing BC Hydro to amend its Electric Tariff to remove language that enables on-bill credits for the CCF Pilot Program grants and removing all references to the COVID-19 Relief Fund for Residential Customers, effective September 1, 2021.

In accordance with section 3 of Order in Council No. 365, issued on June 21, 2021, BCUC Order No. G-203-21 authorized BC Hydro to defer to the CCF Regulatory Account: (a) amounts incurred by BC Hydro in administering the program and, (b) grants provided to residential customers under the program. The total amount deferred must not exceed $5 million.

In response to the Government of B.C.'s Direction to the British Columbia Utilities Commission Respecting COVID-19 Relief (Order in Council No. 159 issued on April 2, 2020), the BCUC approved, by Order No. G-79-20, BC Hydro's application to amend BC Hydro's Electric Tariff in order to implement BC Hydro's COVID Relief Fund for Residential Customers and allow BC Hydro to defer to the CCF Regulatory Account: (i) in addition to the amounts BC Hydro already defers as approved by Order No. G-166-17, those amounts credited to customers under the COVID Relief Fund for Residential Customers; (ii) BC Hydro's costs to administer the COVID Relief Fund for Residential Customers; and (iii) in relation to the balance in the CCF Regulatory Account, interest determined in a fiscal year at a rate equal to BC Hydro's weighted average cost of debt in that fiscal year. The COVID Relief Fund for Residential Customers was a temporary program available until June 30, 2020, for the purpose of providing grants (bill credits) to qualifying customers who lost their employment or became unable to work as a result of the COVID pandemic.

BC Hydro is proposing the recovery of the portion of the CCF Regulatory Account associated with the COVID Relief Fund for Residential Customers balance, as explained in more detail in Chapter 7.

3.10 Mining Customer Payment Plan Regulatory Account

In accordance with section 3(2) of Order in Council No. 123, issued on February 29, 2016, BCUC Order No. G-34-16 authorized BC Hydro to establish the Mining Customer Payment Plan Regulatory Account to defer to future fiscal years amounts equal to the sum of the following related to mining customers participating in the Mining Customer Payment Plan Program:

(i) The account balances of mining customers, if those account balances are impaired;

(ii) Any other amounts that are payable to BC Hydro by mining customers before the closing date and that are impaired; and

(iii) Any taxes paid by BC Hydro on behalf of mining customers on the account balances referred to in subparagraph (i) and amounts referred to in subparagraph (ii).

This Order arose from the Government of B.C.'s decision to allow companies operating metal and coal mines in B.C. to temporarily defer a portion of their electricity payments during periods of low commodity prices.

BCUC Order No. G-34-16 also directed BC Hydro to reduce the Mining Customer Payment Plan Regulatory Account by an amount collected from an applicable mining customer, and to include in the account, interest determined in a fiscal year at the rate of BC Hydro's weighted average cost of debt in that fiscal year. This program closed on March 14, 2021 with no balance in the regulatory account.

In accordance with Order in Council No. 319, BC Hydro announced new COVID-19 relief measures, three new Industrial Customer Payment Plan tariff supplements (TS 97, TS 98, TS 99) that allowed certain industrial customers to temporarily defer payment of a portion of their bills, with repayment plus interest once the programs closed. If any portion of amounts due became uncollectable, that amount would be in scope of the Mining Customer Payment Plan Regulatory Account. The ability to defer payment of bills under these three tariff supplements closed during fiscal 2021. $0.1 million of the deferred amounts owing from customers was deemed impaired under current accounting criteria and as such, that amount was transferred to the regulatory account as of March 31, 2021. However, BC Hydro still expects to fully collect all amounts owing from customers, including the amounts deemed impaired, so a recovery from general ratepayers is not proposed.

In addition, in response to the Government of B.C.’s Direction to the British Columbia Utilities Commission Respecting COVID-19 Relief (Order in Council No. 159 issued on April 2, 2020), the BCUC, by Order No. G-79-20 approved BC Hydro’s application to waive charges for eligible commercial customers during the period from the date that is the later of April 1, 2020 and the date on which an eligible commercial customer ceased operating until June 30, 2020 and defer the waived charges and BC Hydro’s cost of administering this relief for eligible commercial and industrial customers to the Mining Customer Payment Plan Regulatory Account and apply interest at BC Hydro’s weighted average cost of debt.

BC Hydro is proposing to recover the entire balance of the account from ratepayers except for the $0.1 million described above that BC Hydro expects to collect from the participating customer.

3.11 Project Write-off Costs Regulatory Account

In response to Directive 33[16] of the BCUC's Decision on the Fiscal 2020 to Fiscal 2021 RRA, BC Hydro made a separate application for approval to establish a new Project Write-off Costs Regulatory Account to capture the portion of actual project write-off costs in each fiscal year for which BC Hydro believes future recovery from ratepayers is appropriate.[17] BC Hydro's request to establish the Project Write-off Costs Regulatory Account was approved by BCUC Order No. G-337-20 dated December 17, 2020.

In its Decision on the Fiscal 2020 to Fiscal 2021 RRA, the BCUC accepted that some project write-offs are reasonable and to be expected in a utility's normal course of business,[18] but disallowed the recovery of any forecast amounts for project write-offs in the test period revenue requirements as proposed by BC Hydro. However, the BCUC stated that it was willing to consider a regulatory account to capture write-off costs, as follows:

> "The Panel, however, is willing to consider a mechanism, such as the establishment of a regulatory account, to capture BC Hydro's actual project write-off costs for future recovery, provided that in future RRAs BC Hydro also lists all of the projects and costs that have been written-off and captured in the regulatory account along with a description of each project, the rationale for incurring the costs and the rationale for the decision to not continue with the project. In the Panel's view, this would provide the BCUC and interveners with an opportunity to review the reasonableness of these costs. The Panel acknowledges that this would cause a delay between when the write-offs were incurred and when they are recovered. However, if the regulatory account balance is to be cleared over each test period, this would result in minimal intergenerational equity issues and balances the need for BC Hydro to recover these

[16] BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), Directive 33.

[17] Refer to: https://www.bcuc.com/ApplicationView.aspx?ApplicationId=833.

[18] BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 107.

> costs from ratepayers and the BCUC's ability to examine these costs prior to their recovery."[19]

Consistent with the BCUC's recommendation, in the Previous Application, BC Hydro requested BCUC approval to recover amounts deferred to the Project Write-off Costs Regulatory Account in respect of completed fiscal years over the next test period, starting in fiscal 2022 and on an ongoing basis, subject to BCUC review and approval of the recovery of these amounts; apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt; and, recover actual interest charged to the account for amounts related to any completed fiscal years over the next test period. In its Decision on the Previous Application, Directive 16,[20] the BCUC approved BC Hydro's request.

BC Hydro is not requesting any changes to this account in this application.

3.12 Electric Vehicle Costs Regulatory Account

In its Decision on the Fiscal 2020 to Fiscal 2021 RRA, the BCUC denied BC Hydro recovery of electric vehicle charging station costs as the BCUC noted that BC Hydro had not demonstrated, subsequent to the amendment to the *Greenhouse Gas Reduction (Clean Energy) Regulation* (**GGRR**), that the electric vehicle charging stations are prescribed undertakings and encouraged BC Hydro to apply for recovery of its prescribed undertaking costs, stating:

> "The Panel encourages BC Hydro to apply to the BCUC if it wishes to have any of its prior, current or future EV capital expenditures considered as possible prescribed undertakings under the GGRR."

[19] BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), pages 107 to 108.

[20] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), Directive 16.

Under section 18 of the *Clean Energy Act*, the BCUC must set rates that allow BC Hydro to collect sufficient revenue to recover costs incurred for implementing prescribed undertakings.

Therefore, in the Previous Application, BC Hydro requested BCUC approval to establish an Electric Vehicle Costs Regulatory Account to defer any actual operating costs, amortization, and cost of energy amounts related to electric vehicle charging stations that meet the definition of a prescribed undertaking under the GGRR for fiscal 2020 and fiscal 2021; apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt and recover the forecast interest charged to the account each year from the account each year; and, starting in fiscal 2022, recover the forecast balance at the end of a test period over the next test period, until such time that the actual amounts deferred to the account for fiscal 2020 and fiscal 2021 are recovered in rates. In its Decision on the Previous Application, Directive 24,[21] the BCUC approved the establishment of the Electric Vehicle Costs Regulatory Account to defer any actual operating costs, depreciation, and cost of energy amounts related to BC Hydro's EV charging stations that meet the definition of a prescribed undertaking under the GGRR for fiscal 2020 and fiscal 2021 and approved BC Hydro's request to apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt.

The BCUC denied BC Hydro's request to, starting in fiscal 2022, recover the forecast account balance and forecast interest at the end of a test period over the next test period, and directed BC Hydro remove all fiscal 2022 costs related to its EV charging stations that meet the definition of a prescribed undertaking under the GGRR and defer these costs to the Electric Vehicle Costs Regulatory Account. The

[21] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021) Directive 24.

BCUC also directed BC Hydro to apply for a recovery mechanism for the account in this application, which BC Hydro has done in Chapter 7.

3.13 Foreign Exchange Gains and Losses Regulatory Account

By Order No. G-47-02, the BCUC approved the deferral and amortization of foreign exchange gains and losses on the translation of foreign denominated long-term monetary items, using the straight-line pool method, from fiscal 2003 onwards. More specifically, deferred foreign currency translation gains and losses related to long-term debt is amortized over the weighted average remaining term to maturity of the foreign denominated long-term debt portfolio. Deferred foreign currency translation gains and losses related to sinking funds are amortized over the weighted average remaining term to maturity of the sinking fund portfolio.

BC Hydro is not requesting any changes to this account in this application.

3.14 Non-Current Pension Costs Regulatory Account

By Order No. G-16-09 to the Fiscal 2009 to Fiscal 2010 RRA, the BCUC approved the establishment of a regulatory account to defer the difference between forecast and actual non-current pension costs in fiscal 2010. The Fiscal 2011 RRA Negotiated Settlement Agreement extended this regulatory account for fiscal 2011 and directed that the closing fiscal 2011 balance be amortized over a five-year period, beginning in fiscal 2012.

BCUC Order No. G-77-12A extended the account for fiscal 2012 to fiscal 2014 and expanded the scope of the account to include the difference between forecast and actual non-current other post-employment benefit costs, beginning in fiscal 2012. In accordance with Direction No. 7, BCUC Order No. G-48-14 authorized BC Hydro to continue to defer to the account variances between forecast and actual non-current pension costs, on an ongoing basis.

By Order No. G-47-18, the BCUC approved that the portion of the forecast account balance at the start of a test period related to the variances transferred to the account during the previous test period be amortized over the expected average remaining service life (**EARSL**) of the active plan members at the start of the test period. EARSL is determined by BC Hydro's external actuary and is currently 13 years.

In accordance with BCUC Order No. G-47-18, the discount rate used to forecast post-employment benefit plan costs are based on the market discount rate in effect at the time the forecast was prepared.

Please refer to Chapter 5, section 5.12.4.1 for further information on Non-Current Service Costs.

BC Hydro is not requesting any changes to this account in this application.

3.15 PEB Current Pension Costs Regulatory Account

By Order No. G-47-18 to the Fiscal 2017 to Fiscal 2019 RRA, the BCUC approved the establishment of the Post-Employment Benefit (**PEB**) Current Pension Costs Regulatory Account to defer the annual variance between forecast and actual costs related to the operating cost portion of post-employment benefits current pension costs, on an ongoing basis. Order No. G-47-18 also approved that the forecast account balance at the end of a test period be recovered over the next test period.

In accordance with BCUC Order No. G-47-18, the discount rate used to forecast post-employment benefit plan costs are based on the market discount rate in effect at the time the forecast was prepared.

Please refer to Chapter 5, section 5.12.4.2, for further information on Current Service Costs.

BC Hydro is not requesting any changes to this account in this application.

3.16 Debt Management Regulatory Account

By Order No. G-42-16, the BCUC approved the establishment of the Debt Management Regulatory Account, to capture mark-to-market gains and losses of financial contracts that hedge future long-term debt. Hedging the interest rate on future long-term debt enables BC Hydro to mitigate interest rate risk on future long-term debt issuances.

Since fiscal 2017, BC Hydro has locked in interest rates on forecast future long-term debt issuances by entering into financial contracts that hedge the interest rate risk in order to create certainty of financing costs associated with future planned expenditures. In accordance with Order No. G-42-16, the gains and losses from financial contracts that hedge future long-term debt are recorded in the Debt Management Regulatory Account and amortized over the remaining term of the associated long-term debt issuances. These gains and losses are amortized in the test period following the test period in which the long-term debt associated with a particular hedge is issued.

BC Hydro is not requesting any changes to this account in this application.

3.17 DSM Regulatory Account

By Order No. G-55-95, the BCUC directed the deferral and recovery of costs associated with DSM activities. In accordance with Direction No. 7, BCUC Order No. G-48-14 authorized BC Hydro to continue to defer these costs to the DSM Regulatory Account and to amortize the balance of the account into rates over 15 years, on an ongoing basis.

The Direction to the BCUC Respecting the Authority's Thermo-Mechanical Pulp (**TMP**) Program (Order in Council No. 404, issued on July 14, 2015) specified that BC Hydro be allowed to defer costs incurred related to the TMP program, up to $100 million, to the DSM Regulatory Account.

The Direction to the BCUC Respecting Undertaking Costs (Order in Council No. 100, issued on March 1, 2017) specified that BC Hydro be allowed to defer low-carbon electrification expenditures, to the DSM Regulatory Account.

By Order No. G-246-20, the BCUC approved the deferral of low-carbon electrification expenditures to the DSM Regulatory Account, consistent with the Direction to the BCUC Respecting Undertaking Costs.

BC Hydro is not requesting any changes to this account in this application.

3.18 First Nations Costs Regulatory Account

By Order No. G-53-02, the BCUC approved the deferral of costs related to negotiations and settlements with First Nations and approved the amortization of actual negotiation costs and approved settlement costs, over a ten-year period. Settlement payments transferred to the First Nations Costs Regulatory Account from the First Nations Provisions Regulatory Account are not amortized or recovered in rates, pending BCUC approval to do so. In accordance with BCUC Order No. G-11-08, when a settlement is completed, BC Hydro must submit an application to the BCUC for approval to recover the settlement payment in rates. BCUC Order No. G-48-14 directed the amortization of specific amounts from the account for fiscal 2015 and fiscal 2016, and also directed that interest be applied on the account going forward.

Actual transfers to the account in fiscal 2015 and fiscal 2016 were different from the amounts on which the specific amortization in BCUC Order No. G-48-14 was based, which resulted in BC Hydro recording higher amortization than if the amortization had been calculated on actual transfers. This resulted in a credit amount which was refunded to ratepayers over the fiscal 2017 to fiscal 2019 period, consistent with BCUC Order No. G-47-18 to the Fiscal 2017 to Fiscal 2019 RRA.

By Order No. G-47-18 to the Fiscal 2017 to Fiscal 2019 RRA, the BCUC approved, starting in fiscal 2017, and on an ongoing basis that:

(i) Actual lump sum settlement payments be deferred to this account each year, and forecast lump sum settlement payments be amortized over a ten-year period, starting in the year of payment;

(ii) Actual annual settlement payments be deferred to this account each year, and forecast annual settlement payments be amortized in the year of payment;

(iii) Actual negotiation costs be deferred to this account each year, and actual negotiation costs be recovered from the account each year;

(iv) Interest continue to be applied to the balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's weighted average cost of debt, and forecast interest charged to the account be amortized from the account each year;

(v) The forecast account balance at the end of a test period related to the difference between the amortization of the forecast annual and lump sum settlement payments and the calculation of amortization based on the actual annual and lump sum settlement payments during that test period be recovered over the next test period; and

(vi) The forecast account balance at the end of a test period related to the difference between the forecast interest recovered and the actual interest charged to the account during that test period be recovered over the next test period.

For items (i) and (ii) above, the year of payment refers to the year the payment is forecast to be made.

BC Hydro is not requesting any changes to this account in this application.

3.19 Site C Regulatory Account

By Order No. G-143-06, the BCUC approved the creation of a regulatory account related to Site C Project expenditures and approved deferral of project costs incurred in fiscal 2007 and fiscal 2008 to the account. The Fiscal 2009 to Fiscal 2010 RRA Decision and Fiscal 2011 RRA Negotiated Settlement Agreement extended the deferral of project costs to the Site C Regulatory Account to the end of fiscal 2011. By Order No. G-77-12A to the Fiscal 2012 to Fiscal 2014 Amended RRA, the BCUC authorized the deferral of all operating costs incurred related to the Site C Project in fiscal 2012 to fiscal 2014. By Order No. G-48-14, the BCUC authorized the deferral of all operating costs incurred in fiscal 2015 and fiscal 2016.

Following the final investment decision by the Government of B.C. to proceed with the Site C Project, BC Hydro commenced capitalization of costs related to the project starting in January 2015. While BC Hydro has commenced capitalization of costs, certain costs related to the project may not be eligible for capitalization under IFRS. For example, some legal costs are not eligible for capitalization under IFRS.

By Order No. G-47-18, the BCUC approved the deferral of any costs related to the Site C Project that are not able to be capitalized under the Prescribed Standards, to the Site C Regulatory Account.

In Directive 44[22] of its Decision on BC Hydro’s Fiscal 2020 to Fiscal 2021 RRA, the BCUC approved BC Hydro’s request to remove the reference to the “Prescribed Standards” from the scope of what may be deferred to the Site C Regulatory Account, as BC Hydro has fully adopted IFRS. This allowed BC Hydro to continue to

[22] Directive 44; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020).

defer to the Site C Regulatory Account any costs related to the Site C Project that are not able to be capitalized under IFRS.

Under IFRS, the amortization of the Debt Management Regulatory Account cannot be classified as finance charges and as such cannot be included in the calculation of BC Hydro's interest during construction that is applied to the Site C project. As these amounts cannot be capitalized under IFRS, they are deferred to the Site C Regulatory Account.

BC Hydro is requesting commencement of recovery of this account in Chapter 7.

3.20 Pre-1996 Contributions in Aid of Construction Regulatory Account

In fiscal 2006 BC Hydro retained Gannett Fleming to complete a depreciation study, which was filed as part of the Fiscal 2007 to Fiscal 2008 RRA. Gannett Fleming recommended that the amortization period for assets referred to as “Profile ID 99403 Distribution Pre-1996 Contributions in Aid” be increased from the then-approved period of 25 years to 45 years.

However, section 7(iv) of the Fiscal 2007 to Fiscal 2008 RRA Negotiated Settlement Agreement approved by BCUC Order No. G-143-06 committed BC Hydro to maintain the amortization period for these assets at 25 years. In its financial records BC Hydro changed the amortization period for these assets from 25 to 45 years to match the depreciation study, and implemented the Fiscal 2007 to Fiscal 2008 RRA Negotiated Settlement Agreement commitment by creating a regulatory account to capture the difference in the revenue requirement impacts of a 45-year amortization period and a 25-year amortization period. This regulatory account will be fully amortized at the end of fiscal 2040.

BC Hydro is not requesting any changes to this account in this application.

3.21 SMI Regulatory Account

By Order No. G-64-09, the BCUC approved the establishment of the Smart Metering and Infrastructure Program (**SMI**) Regulatory Account to defer the operating costs incurred by BC Hydro related to the Smart Metering and Infrastructure Program in fiscal 2009. By Order No. G-67-10, the BCUC approved the deferral of these costs for fiscal 2010. BCUC Order No. G-115-11 authorized BC Hydro to include its actual fiscal 2011 Smart Metering and Infrastructure Program operating costs up to $5.8 million in the SMI Regulatory Account. BCUC Order No. G-77-12A to the Fiscal 2012 to Fiscal 2014 Amended RRA approved the deferral of actual net operating costs, amortization on capital assets, finance charges, and return on equity related to the SMI program from fiscal 2012 to fiscal 2014, to the SMI Regulatory Account.

By Order No. G-166-13, and in accordance with section 3(2) of Direction No. 4, BC Hydro was directed to defer to the account:

- Program costs;
- Investigation costs and infrastructure costs that are not recovered from eligible customers at premises where a legacy meter or radio-off meter is installed; and
- Costs related to smart meters, which are incurred during the period January 1, 2013 to March 31, 2014.

By Order No. G-48-14 to the Fiscal 2015 to Fiscal 2016 Revenue Requirements Rate Application, the BCUC approved the amortization of specific amounts in fiscal 2015 and fiscal 2016 from the SMI Regulatory Account and also approved deferral of the net operating costs incurred in fiscal 2015 to fiscal 2016 related to the SMI Program, to the account. As the SMI Program is now complete and operationalized, no further additions are being made to this regulatory account.

By Order No. G-47-18 to BC Hydro's Fiscal 2017 to Fiscal 2019 RRA, the BCUC approved the recovery of the fiscal 2016 closing account balance over a period of 13 years, starting in fiscal 2017, which is the remaining period of the original 15-year amortization period proposed in the Regulatory Accounts Report filed in the Fiscal 2015 to Fiscal 2016 Revenue Requirements Rate Application. The 15-year amortization is based on the average life of SMI assets. BCUC Order No. G-47-18 also approved that interest continue to be applied to the balance of this regulatory account. Interest is applied to the account at BC Hydro's weighted average cost of debt and forecast interest is recovered from the account each year.

BC Hydro is not requesting any changes to this account in this application.

3.22 First Nations Provisions Regulatory Account

By Order No. G-56-06, the BCUC approved the establishment of a regulatory asset corresponding to the amount of a loss provision that BC Hydro recorded on its financial statements as required under the accounting standards related to two First Nations claims. By Order No. G-11-08, the BCUC amended the First Nations Provisions Regulatory Account to allow the balance of the regulatory account to reflect loss provisions as required under the accounting standards, related to any First Nations claim, and to allow the periodic adjustment of the balance of the regulatory account to reflect adjustments to the loss provisions required under the accounting standards.

BC Hydro's settlements with First Nations may include both lump sum payments and annual payments. When settlement payments are made, corresponding amounts are transferred from the First Nations Provisions Regulatory Account to the First Nations Costs Regulatory Account and recovered in rates through amortization of that regulatory account.

BC Hydro is not requesting any changes to this account in this application.

3.23 Environmental Provisions Regulatory Account

By Order No. G-88-10, the BCUC approved the establishment of the Environmental Provisions Regulatory Account in the amount of the loss provision liability recognized by BC Hydro in its financial statements, related to compliance with the polychlorinated biphenyl regulations and remediation of environmental contamination at Rock Bay. Order No. G-88-10 also approved periodic adjustments to the amounts in the regulatory account to match the changes required under the accounting standards in the loss provision liability. By Order No. G-7-13, the terms of the Environmental Provisions Regulatory Account were expanded to include the loss provision liability related to asbestos remediation at BC Hydro's facilities.

As BC Hydro makes actual expenditures related to compliance with the polychlorinated biphenyl regulations and the remediation of asbestos at its facilities, the balance in the Environmental Provisions Regulatory Account is reduced accordingly.

Actual costs of remediation activities at Rock Bay were deferred to the Rock Bay Remediation Regulatory Account as they were incurred, and the provision was reduced by an equal amount. Remediation of the Rock Bay property was completed in fiscal 2019, and the balance in the Environmental Provisions Regulatory Account related to Rock Bay has been reduced accordingly. In the Previous Application, BC Hydro requested BCUC approval to close the Rock Bay Remediation Regulatory Account at the end of fiscal 2022 as its balance will be fully amortized into rates at that time. In its Decision on the Previous Application, Directive 17,[23] the BCUC approved the closure of the Rock Bay Remediation Regulatory Account at the end of fiscal 2022, or a subsequent fiscal year, when the account balance is zero.

[23] BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021) Directive 17.

Actual costs related to asbestos remediation are deferred to the Remediation Regulatory Account as they are incurred, and the provision is reduced by an equal amount.

Actual costs related to compliance with polychlorinated biphenyl regulations were expensed as incurred until the end of fiscal 2016, and the Environmental Provisions Regulatory Account was reduced by an equal amount. By Order No. G-47-18 to the Fiscal 2017 to Fiscal 2019 RRA, BCUC approved that, starting in fiscal 2017, and on an ongoing basis, actual costs related to compliance with polychlorinated biphenyl regulations be deferred to the Remediation Regulatory Account as they are incurred and the provision be reduced by an equal amount. This is similar to the treatment of the costs associated with asbestos remediation.

BC Hydro is not requesting any changes to this account in this application.

3.24 IFRS Property, Plant and Equipment Regulatory Account

The IFRS Property, Plant and Equipment Regulatory Account enables the deferral of overhead costs that can no longer be capitalized under IFRS, as they are not directly attributable to the construction of an asset. Under Canadian Generally Accepted Accounting Principles (**CGAAP**), costs related to administration and general overhead were eligible for capitalization to Property, Plant, and Equipment.

BCUC Order No. G-77-12A to BC Hydro's Fiscal 2012 to Fiscal 2014 Amended RRA implemented BC Hydro's proposal that overhead costs that can no longer be capitalized be deferred and transitioned into operating expenditures over 10 years to avoid immediate and significant rate impacts. BCUC Order No. G-77-12A implemented this proposal and set the amortization period at 40 years, starting in fiscal 2013.

In the Fiscal 2012 to Fiscal 2014 Amended RRA, BC Hydro included a proposal to transition the overhead costs that could no longer be capitalized under IFRS into rates over a ten-year period. Under this proposal 100 per cent of ineligible overhead costs were charged to the IFRS Property, Plant and Equipment Regulatory Account in fiscal 2012. Starting in fiscal 2013, the percentage of the ineligible overhead costs to be charged to the regulatory account was reduced by 10 per cent each year. The additions of ineligible overhead costs to the account ceased in fiscal 2021.

In the Fiscal 2012 to Fiscal 2014 Amended RRA, BC Hydro also proposed to amortize the additions to the IFRS Property, Plant and Equipment Regulatory Account over 40 years. This amortization period was based on the composite life of BC Hydro's assets so that the overhead costs would be matched with the benefits of the underlying assets.

If BC Hydro had recognized the impact of the transition to IFRS in rates at the time of the transition, the rate impact for customers would have been immediate and significant. Amortizing these costs over a 40-year period allows these costs to be recovered over a similar period of time as was required under CGAAP, the accounting rules that BC Hydro followed prior to IFRS. Accordingly, a 40-year amortization period also results in approximately the same revenue requirement impact under IFRS as under the previous CGAAP rules. This means that ratepayers are not subject to higher rates as a result of changes in accounting standards. BC Hydro believes that the existing amortization period of 40 years continues to be appropriate.

BC Hydro is not requesting any changes to this account in this application.

3.25 IFRS Pension Regulatory Account

Upon the transition to IFRS in fiscal 2013, BC Hydro was required to recognize all unamortized actuarial gains and losses on the pension and other post-employment benefit plans, not previously recognized in its financial statements.

In the Fiscal 2012 to Fiscal 2014 Amended RRA, BC Hydro requested the establishment of the IFRS Pension Regulatory Account with an opening liability balance equal to the actual unamortized actuarial gains and losses on the pension and other post-employment benefit plans, which BC Hydro had to recognize in its financial statements at the time of conversion to IFRS. BCUC Order No. G-77-12A implemented this request and also set the amortization period at 20 years on a straight-line basis, starting in fiscal 2013.

Amortizing these costs over a 20-year period results in approximately the same revenue requirement impact under IFRS as under the previous CGAAP rules. This means that ratepayers are not subject to higher rates as a result of changes in accounting standards. BC Hydro believes that the existing amortization period of 20 years continues to be appropriate.

BC Hydro is not requesting any changes to this account in this application.

4 Summary of BC Hydro's Regulatory Accounts and Approach to Recovery

Table R-4 below provides a summary of the information contained in this appendix for each of BC Hydro's approved regulatory accounts discussed in this appendix. For clarity, the table excludes the two accounts requested that have not received BCUC approval.

Table R-4 Summary of BC Hydro's Regulatory Accounts

		Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate
1	Heritage Deferral Account	Captures variances related to BC Hydro's Heritage Cost of Energy as well as other items approved by the BCUC.	Net Forecast Cost of Energy Variance Account balance is recovered/ refunded based on DARR table mechanism as approved for fiscal 2022 and proposed going forward.	DARR table mechanism: • Minimizes intergenerational inequity by being responsive to the changing net balance in the Cost of Energy Variance Accounts; maintains rate stability for customers to the extent practicable; and • Is administratively simple and transparent.
2	Non-Heritage Deferral Account	Captures variances related to BC Hydro's Non-Heritage Cost of Energy (i.e., IPPs) as well as other items approved by the BCUC.	Net Forecast Cost of Energy Variance Account balance is recovered/ refunded based on DARR table mechanism as approved for fiscal 2022 and proposed going forward.	DARR table mechanism: • Minimizes intergenerational inequity by being responsive to the changing net balance in the Cost of Energy Variance Accounts; maintains rate stability for customers to the extent practicable; and • Is administratively simple and transparent.
3	Trade Income Deferral Account	Captures variances between forecast and actual Trade Income (i.e., Powerex).	Net Forecast Cost of Energy Variance Account balance is recovered/ refunded based on DARR table mechanism as approved for fiscal 2022 and proposed going forward.	DARR table mechanism: • Minimizes intergenerational inequity by being responsive to the changing net balance in the Cost of Energy Variance Accounts; maintains rate stability for customers to the extent practicable; and • Is administratively simple and transparent.

		Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate
4	Load Variance Regulatory Account	Capture variances between forecast and actual domestic customer load (referred to as the Domestic Revenue Variance).	Net Forecast Cost of Energy Variance Account balance is recovered/ refunded based on DARR table mechanism as approved for fiscal 2022 and proposed going forward.	DARR table mechanism: • Minimizes intergenerational inequity by being responsive to the changing net balance in the Cost of Energy Variance Accounts; maintains rate stability for customers to the extent practicable; and • Is administratively simple and transparent.
5	Biomass Energy Program Variance Regulatory Account	Capture all variances between forecast and actual amounts related to the Biomass Energy Program.	Net Forecast Cost of Energy Variance Account balance is recovered/ refunded based on DARR table mechanism as approved for fiscal 2022 and proposed going forward.	DARR table mechanism: • Minimizes intergenerational inequity by being responsive to the changing net balance in the Cost of Energy Variance Accounts; maintains rate stability for customers to the extent practicable; and • Is administratively simple and transparent.
6	Low Carbon Fuel Credits Regulatory Account	Capture variances between forecast and actual miscellaneous revenue from low carbon fuel credits.	Net Forecast Cost of Energy Variance Account balance is recovered/ refunded based on DARR table mechanism as approved for fiscal 2022 and proposed going forward.	DARR table mechanism: • Minimizes intergenerational inequity by being responsive to the changing net balance in the Cost of Energy Variance Accounts; maintains rate stability for customers to the extent practicable; and • Is administratively simple and transparent.

		Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate
7	Storm Restoration Costs	Captures variances between forecast and actual storm restoration costs and revenue impacts (variances) from the evacuation relief provided under the Evacuation relief tariff.	Next Test Period.	The expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.
8	Amortization of Capital Additions	Captures variances between forecast and actual amortization of capital additions.	Next Test Period.	These expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.
9	Total Finance Charges	Captures variances between forecast and actual finance charges	Next Test Period.	These expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.
10	Remediation	Captures variances between forecast and actual costs incurred related to compliance with Polychlorinated Biphenyl Regulations (**PCB**) and Asbestos remediation at BC Hydro facilities.	Next Test Period.	These expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.

		Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate
11	Real Property Sales	Captures variances between forecast and actual gain/loss on real estate sales.	Balance recovered from actual recognition of gains on sale. BC Hydro proposes to recover/refund the balance in the account, at the beginning of the next test period, over the next test period and continue to record only actual net gains	Smooths the recognition of gains and losses as sales will not occur uniformly over the 10 years since fiscal 2015.
12	Dismantling Cost	Captures variances between forecast and actual Dismantling Costs.	Next Test Period.	These expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.
13	Customer Crisis Fund	Captures the net difference between Customer Crisis Fund Rate Rider revenues and BC Hydro's incremental costs related to the Customer Crisis Fund pilot program and costs related to COVID-19 relief measures for residential customers. From June 2021, this account will capture administration costs of the program and grants provided to residential customers to a maximum of $5 million.	Next Test Period for COVID-19 relief measures costs only. No recovery/refund requested for Customer Crisis Fund balance	These expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.

		Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate
14	Mining Customer Payment Plan	Captures any amounts impaired related to mining customers participating in the Mining Customer Payment Plan Program and costs related to COVID-19 relief measures for commercial and industrial customers	Next Test Period for COVID-19 relief measures only. No recovery for Mining Customer Payments Plan deferral balance.	These expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.
15	Project Write-off Costs	Captures a portion of actual project write off costs in each fiscal year	Next Test Period	These expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.
16	Electric Vehicle Costs	Captures operating costs, amortization, and cost of energy amounts related to electric vehicle charging stations for fiscal 2020, fiscal 2021 and fiscal 2022	Next Test Period proposed	These expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.

		Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate
18	Fiscal 2022 Depreciation Study Impact[24]	Captures the variances arising in fiscal 2022 from the changes determined in the Depreciation Study	Next Test Period proposed	These expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.
19	Foreign Exchange Gains/Losses	Captures foreign exchange gains and losses on the translation of foreign denominated long-term monetary items.	Straight-line Pool Method	The recovery period matches the underlying attribute and should be recovered over a longer period of time (i.e., foreign denominated long-term monetary items).
20	Non-Current Pension Costs	Captures variances between forecast and actual non-current pension costs.	Over Average Remaining Service Life of Active Employee Group (**EARSL**) - currently 13 years	The recovery period matches the underlying attribute and should be recovered over a longer period of time (i.e., remaining life of employee group).
21	PEB Current Pension Costs	Captures operating cost variances between forecast and actual current pension costs.	Next Test Period.	These expenditures provide immediate, rather than long-term benefits (i.e., current pension costs).
22	Debt Management	Captures mark-to-market gains and losses on financial contracts that hedge future long-term debt.	Over remaining term of associated long-term debt issuances.	The recovery period matches the underlying attribute (i.e., long-term debt Issuance).

24 In its Decision on the Previous Application, Directive 15, the BCUC directed BC Hydro to establish a new regulatory account to capture the variances arising in fiscal 2022 as a result of any changes to the depreciation expense determined in the depreciation study

		Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate
23	DSM	Captures expenditures associated with Demand-Side Management activities. These expenditures result in future energy savings.	Over 15 years.	Matches the future benefit period for customers, which is the average measure life of DSM initiatives.
24	First Nations Costs	Captures First Nations annual and lump sum settlement payments and negotiation costs.	Over 10 years for lump sum settlement payments, annual settlement payments, which are amortized each year.	Lump sum settlements are amortized over a longer period of time to smooth the impact on rate.
25	Site C	Captures costs related to the Site C project prior to the final investment decision to proceed with the project, and costs that are not eligible for capitalization thereafter.	Over the weighted average life of the Site C assets of 84 years proposed.	Matches the benefits period of the Site C assets.
26	Pre-1996 Contributions in Aid of Construction	Captures the difference between the 25-year amortization period required for regulatory purposes and the 45-year amortization period required for financial reporting for this asset class.	Over 45 years (to fiscal 2040)	Matches the 45-year amortization period determined in a depreciation study filed in the Fiscal 2007-Fiscal 2008 RRA.

		Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate
27	SMI	Captured operating costs related to the SMI Program. The SMI Program is complete and no further additions are being made to this account.	Over 15 years (to fiscal 2029)	Matches the future benefit period for customers, which is the average life of the SMI assets.
29	First Nations Provisions	Regulatory provision established for BC Hydro's liability in respect of First Nations claims.	Amounts recovered in First Nations Costs Regulatory Account as settlement payments are made	Since non-cash provisions are not recovered in rates, no recovery mechanism is required. The provision is drawn down when actual expenditures are charged to the regulatory account and the amounts are recovered from the corresponding expenditure regulatory account (i.e., First Nations Costs Regulatory Account).
30	Environmental Provisions	Regulatory provision established for BC Hydro's liability in respect of compliance with Polychlorinated Biphenyl Regulations, and asbestos remediation at BC Hydro facilities.	Amounts recovered in Remediation Regulatory Account as expenditures are incurred	Since non-cash provisions are not recovered in rates, no recovery mechanism is required. The provision is drawn down when actual expenditures are charged to the regulatory account and the amounts are recovered from the corresponding expenditure regulatory account (i.e., Remediation Regulatory Account (PCB and Asbestos) and the Rock Bay Remediation Regulatory Account).

		Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate
31	IFRS Property, Plant and Equipment	Captures capital overhead costs that were eligible for capitalization under CGAAP but can no longer be capitalized under IFRS. The additions to the account were completed in fiscal 2021.	Rolling 40-year period (to fiscal 2061)	Recovered on the same basis as under the previous CGAAP accounting rules. Therefore, ratepayers are not impacted by higher rates as a result of changes in accounting standards.
32	IFRS Pension	Captures unamortized gains/losses on BC Hydro's pension plans that were required to be recognized in BC Hydro's financial statements upon transition to IFRS.	Over 20 years (to fiscal 2032)	Recovered on the same basis as under the previous CGAAP accounting rules. Therefore, ratepayers are not impacted by higher rates as a result of changes in accounting standards.

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix S

Fiscal 2021 Debt Management Regulatory Account Status Report

BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission

Appendix B

Debt Management Regulatory Account Annual Status Report

April 1, 2020 to March 31, 2021

Table of Contents

Appendices

Background

On March 30, 2016, the BCUC issued Order No. G-42-16 which authorized BC Hydro to establish a Debt Management Regulatory Account (**DMRA**) to capture mark-to-market gains and losses on financial contracts that hedge future long-term debt to mitigate interest rate risk related to future long-term debt that BC Hydro intends to issue. In compliance with Directive 4 of that Order, BC Hydro provides below its annual report on the DMRA.

Report as at March 31, 2021

During fiscal 2021, BC Hydro did not enter into any future debt hedges (**FDHs**) to mitigate interest rate risk on future long-term debt that BC Hydro intends to issue as we reached our hedging target as per our Liability Risk Management policy. The existing outstanding hedges consist of 10-year and 30-year interest rate swaps, with remaining contract maturity dates ranging from approximately three months to 3.25 years and forecast borrowing yields ranging from 3.15 per cent to 3.67 per cent.

Since the establishment of the DMRA and as at March 31, 2021, a total of $10.0 billion of FDHs have been placed, of which $3.2 billion remain outstanding. Based on BC Hydro's 2021/22 to 2023/24 Service Plan, at March 31, 2021, BC Hydro had hedged approximately 40 per cent of forecast long-term debt issuances for fiscal 2022 to fiscal 2025. The details of all FDHs are included in Appendix 1.

Lower (higher) long-term interest rates result in lower (higher) interest costs on the associated future long-term debt issues when issued. These lower (higher) interest costs on the associated debt issues provide an offset to the impact of the FDH losses (gains). This results in the net effect of locking in the interest rate and mitigating interest rate risk related to future long-term debt that BC Hydro intends to issue.

Any realized gains and losses will be amortized over the remaining term of the issued debt starting at the beginning of the test period following the test period during which the long-term debt associated with a particular hedge is issued. As a result, the effective interest rate on hedged debt is a combination of the gain or loss on the settled FDH and the yield of the underlying debt issuance.

At March 31, 2021, the DRMA had a balance of $449 million (after amortization). This balance included:

- $126 million of net unrealized losses on the $3.2 billion of outstanding FDHs;
- $298 million of net realized losses on the $6.8 billion of settled FDHs; and
- $25 million of amortization related to net realized gains on the $4.0 billion of FDHs settled during fiscal 2017 to fiscal 2019.

This was a net decrease of $504 million from the balance at March 31, 2020 of $953 million to the balance at March 31, 2021 of $449 million. The $504 million decrease was due to:

- $571 million related to increases in the unrealized mark-to-market value of the $3.2 billion of outstanding FDHs; partially offset by:
- $55 million related to decreases in the value of the $1.8 billion of FDHs that were settled during fiscal 2021; and
- $12 million related to the amortization of net realized gains on the $4.0 billion of FDHs settled during fiscal 2017 to fiscal 2019.

The increase in the value of the outstanding FDHs was due to a significant increase in long-term interest rates during fiscal 2021. The decrease in the value of the FDHs settled during fiscal 2021 was a result of a decrease in long-term interest rates at the time the FDHs were settled relative to the beginning of the fiscal year.

The net unrealized loss of $126 million relating to the $3.2 billion in outstanding FDHs remains sensitive to changes in long-term yields and will continue to change until the hedges are settled. A 100-basis point change in long-term yields would result in a change of approximately $400 million to $550 million in the value of the $3.2 billion in outstanding FDHs.

BC Hydro
Power smart

BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission

Appendix B

Appendix 1

Future Debt Hedges Report

Future Debt Hedges Report

As of March 31, 2021
(in millions of Canadian dollars)

Name	Execution Date	Transaction Type	Forecast Debt Issuance & Contract Maturity Year	Contract Settlement Date	Hedge Term	Notional Amount	Forecast Borrowing Yield	Actual Yield	Fair Market Value[2]	Settlement Value[2]	Total DMRA Balance Before Amortization[2]	Amortization	DMRA Balance[2]
Hedges Placed F2017													
FDH1 [1]	2016-05-16	Bond Lock	F2017	16-Nov	10 years	200	2.24%	3.01%		2.7	2.7	(0.2)	2.5
FDH2A	2016-05-11	Bond Lock	F2017	16-Sep	30 years	200	2.97%	3.00%		(11.3)	(11.3)	0.8	(10.5)
FDH2B	2016-05-12	Bond Lock	F2017	16-Sep	30 years	100	3.01%	3.00%		(6.7)	(6.7)	0.5	(6.2)
FDH3	2016-05-18	Bond Lock	F2018	17-Mar	10 years	300	2.36%	2.35%		8.0	8.0	(1.9)	6.1
FDH4	2016-05-24	Bond Lock	F2018	17-Oct	10 years	200	2.38%	2.37%		7.4	7.4	(1.8)	5.6
FDH5	2016-05-31	Bond Lock	F2018	17-Jun	30 years	200	3.04%	2.87%		0.1	0.1	(0.0)	0.1
FDH6	2016-09-23	Swap	F2018	17-Oct	10 years	200	2.09%	1.83%		17.0	17.0	(4.1)	12.9
FDH7	2016-09-23	Swap	F2018	17-Oct	10 years	200	2.08%	1.82%		17.2	17.2	(4.2)	13.0
FDH8	2016-09-26	Swap	F2018	17-Sep	30 years	200	2.64%	2.27%		40.9	40.9	(2.8)	38.1
FDH9	2016-09-29	Swap	F2019	18-May	10 years	200	2.09%	1.84%		22.7	22.7	(4.7)	18.0
FDH10	2016-10-06	Swap	F2019	18-Apr	30 years	200	2.76%	2.14%		38.7	38.7	(2.6)	36.1
FDH11	2016-06-08	Swap	F2019	18-Sep	10 years	300	2.53%	2.16%		22.4	22.4	(4.6)	17.8
FDH12	2016-06-08	Swap	F2019	18-Sep	10 years	200	2.54%	2.17%		14.7	14.7	(3.0)	11.7
FDH13	2016-06-14	Swap	F2020	19-Jun	10 years	300	2.54%	2.18%		(0.4)	(0.4)	0.0	(0.4)
FDH14	2016-06-22	Swap	F2020	19-Oct	10 years	200	2.74%	2.44%		(3.1)	(3.1)	0.0	(3.1)
FDH15	2016-10-12	Swap	F2020	19-Oct	10 years	200	2.57%	2.24%		0.7	0.7	0.0	0.7
FDH16	2016-10-13	Swap	F2021	20-May	10 years	300	2.60%	2.44%		(28.2)	(28.2)	0.0	(28.2)
FDH17	2016-10-13	Swap	F2021	20-Jun	10 years	200	2.60%	2.31%		(16.5)	(16.5)	0.0	(16.5)
FDH18	2016-10-20	Swap	F2021	20-Sep	10 years	300	2.69%	2.25%		(27.9)	(27.9)	0.0	(27.9)
FDH19	2016-10-20	Swap	F2021	20-Sep	10 years	200	2.69%	2.27%		(18.3)	(18.3)	0.0	(18.3)
Subtotal						**$4,400**			**$0.0**	**$80.1**	**$80.1**	**($28.8)**	**$51.3**
Hedges Placed F2018													
FDH20	2017-09-29	Bond Lock	F2019	18-Jul	10 years	200	2.96%	2.88%		(1.6)	(1.6)	0.3	(1.3)
FDH21	2017-10-03	Bond Lock	F2019	18-Jul	10 years	200	3.00%	2.92%		(2.2)	(2.2)	0.4	(1.7)
FDH22	2017-09-29	Bond Lock	F2019	18-Jul	30 years	200	3.35%	3.36%		(17.3)	(17.3)	1.2	(16.1)
FDH23A	2017-10-04	Bond Lock	F2019	18-Jun	10 years	100	3.01%	2.84%		(0.4)	(0.4)	0.1	(0.3)
FDH23B	2017-10-04	Bond Lock	F2019	18-Jun	10 years	100	3.01%	2.87%		(0.4)	(0.4)	0.1	(0.3)
FDH24A	2017-10-02	Bond Lock	F2019	18-Aug	30 years	100	3.36%	3.35%		(6.4)	(6.4)	0.4	(6.0)
FDH24B	2017-10-03	Bond Lock	F2019	18-Aug	30 years	100	3.38%	3.37%		(6.8)	(6.8)	0.4	(6.4)
FDH25	2017-09-28	Bond Lock	F2019	18-Aug	30 years	250	3.37%	3.36%		(16.7)	(16.7)	1.1	(15.6)
FDH26/27	2018-01-29	Swap	F2020	19-Jun	30 years	50	3.44%	3.16%		(6.7)	(6.7)	0.0	(6.7)
FDH28	2018-02-05	Swap	F2021	20-Jun	30 years	75	3.64%	4.01%		(30.9)	(30.9)	0.0	(30.9)
FDH29	2018-02-05	Swap	F2021	20-Sep	30 years	75	3.64%	3.82%		(29.7)	(29.7)	0.0	(29.7)
FDH30/31	2018-02-08	Swap	F2022		30 years	175	3.67%		(16.4)		(16.4)		(16.4)
FDH32	2018-02-06	Swap	F2022		30 years	100	3.60%		(7.6)		(7.6)		(7.6)
FDH33	2018-02-07	Swap	F2022		30 years	100	3.58%		(7.2)		(7.2)		(7.2)
FDH34/35	2018-02-01	Swap	F2023		30 years	250	3.52%		(11.0)		(11.0)		(11.0)
FDH36/37	2018-01-24	Swap	F2023		30 years	200	3.40%		(3.5)		(3.5)		(3.5)
Subtotal						**$2,275**			**($45.7)**	**($118.9)**	**($164.6)**	**$4.0**	**($160.6)**
Hedges Placed F2019													
FDH38	2018-12-07	Swap	F2022		10 years	125	3.33%		(7.5)		(7.5)		(7.5)
FDH39	2018-12-06	Swap	F2023		10 years	100	3.40%		(4.3)		(4.3)		(4.3)
FDH40	2018-12-07	Swap	F2023		10 years	125	3.41%		(4.6)		(4.6)		(4.6)
FDH41	2018-12-07	Swap	F2024		10 years	175	3.46%		(4.4)		(4.4)		(4.4)
FDH42	2018-12-06	Swap	F2024		30 years	175	3.62%		(7.3)		(7.3)		(7.3)
FDH43	2019-01-15	Bond Lock	F2020	19-Jun	30 years	150	3.13%	3.07%		(18.8)	(18.8)	0.0	(18.8)
FDH44	2019-01-16	Bond Lock	F2020	19-Sep	30 years	125	3.17%	3.24%		(23.1)	(23.1)	0.0	(23.1)
FDH45A	2019-01-17	Bond Lock	F2021	20-Jun	30 years	200	3.20%	3.54%		(60.4)	(60.4)	0.0	(60.4)
FDH45B	2019-01-17	Bond Lock	F2021	20-Jun	30 years	125	3.20%	3.47%		(40.4)	(40.4)	0.0	(40.4)
FDH46A	2019-01-15	Swap	F2021	20-Sep	30 years	100	3.43%	3.51%		(34.6)	(34.6)	0.0	(34.6)
FDH46B	2019-01-16	Swap	F2021	20-Aug	30 years	225	3.49%	3.69%		(82.2)	(82.2)	0.0	(82.2)
FDH47	2019-01-08	Swap	F2022		10 years	275	3.15%		(12.3)		(12.3)		(12.3)
FDH48	2019-01-09	Swap	F2022		30 years	100	3.41%		(3.9)		(3.9)		(3.9)
FDH49	2019-01-09	Swap	F2022		10 years	300	3.22%		(13.5)		(13.5)		(13.5)
FDH50	2019-01-10	Swap	F2022		30 years	175	3.41%		(5.8)		(5.8)		(5.8)
FDH51	2019-01-14	Swap	F2023		10 years	250	3.26%		(7.6)		(7.6)		(7.6)
FDH52	2019-01-10	Swap	F2023		10 years	125	3.27%		(3.2)		(3.2)		(3.2)
FDH53	2019-01-11	Swap	F2023		30 years	100	3.42%		(1.8)		(1.8)		(1.8)
FDH54	2019-01-09	Swap	F2024		10 years	175	3.33%		(2.5)		(2.5)		(2.5)
FDH55	2019-01-08	Swap	F2024		30 years	125	3.44%		(0.9)		(0.9)		(0.9)
FDH56	2019-01-15	Swap	F2025		10 years	75	3.39%		(0.4)		(0.4)		(0.4)
Subtotal						**$3,325**			**($79.9)**	**($259.5)**	**($339.4)**	**$0.0**	**($339.4)**
Total						**$10,000**			**($125.6)**	**($298.2)**	**($423.9)**	**($24.7)**	**($448.6)**

[1] Actual debt was a 30 year issue.
[2] Gain / (loss) deferred to the Debt Management Regulatory Account

BC Hydro
Power smart

BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission

Appendix B

Appendix 2

Glossary for Appendix 1

Name	BC Hydro reference for each individual FDH.
Execution Date	Date the FDH was entered into.
Transaction Type	Type of Future Debt Hedge **Bond Locks** – contracts with financial institutions that are based on the performance of Government of Canada Treasury Bonds. Under a Bond Lock, BC Hydro will effectively sell a particular Government of Canada Bond at the current interest rate and effectively repurchase it at a pre-defined future date at the then-prevailing market interest rate **Forward Swaps** – contracts with financial institutions whereby BC Hydro will pay the current interest rate on the Interest Rate Swap[1] and agree to receive the prevailing interest rate on the Interest Rate Swap at a pre-defined future date.
Forecast Debt Issuance and Contract Maturity Year	Fiscal year the FDH derivative contract is forecast to be unwound and cash settled (set at the inception of the hedge) and the related future debt is expected to be issued.
Contract Settlement Date	Date the FDH derivative was actually unwound and cash settled.
Hedge Term	The term of the future debt issue that is being hedged (i.e., either a 10-year debt issue or a 30-year debt issue).
Notional Amount	The dollar value of the FDH derivative. The notional amount of the derivative will be equal to the principal amount of the related future debt issue.
Forecast Borrowing Yield	The anticipated yield on a particular future debt issue on the day the FDH was executed. The forecast borrowing yield is subject to change based on the difference between the change in the yield on Government of B.C. Bonds vs. the change in the yield on the underlying FDHs (Bond lock or Forward Swap) since the inception of the hedges. The actual yield will only be known upon the cash settlement of the FDH and the issuance of the related future debt.
Actual Yield	The effective yield on the future debt issuance taking into account the gain or loss on the related FDH.
Fair Market Value	The mark to market value of the FDHs that are not yet cash settled.
Settlement Value	The amount of cash paid out by BC Hydro or received by BC Hydro upon the unwinding and cash settlement of the FDH. A loss on the FDH would involve a cash payment by BC Hydro and a gain on the FDH would involve a receipt of cash by BC Hydro.
Total DMRA Balance Before Amortization	The amount of gain or loss on FDHs recorded in the DMRA since inception. Comprised of mark to market gains and losses and settlement gains and losses.

[1] A Canadian Interest Rate Swap is an agreement between two counterparties that agree to exchange an interest payment based on the CDOR Canadian Dollar Offer Rate index.

Amortization	The amount removed from the DMRA and included in Net Income. The gains or losses in the DMRA will be amortized over the remaining term of the associated long-term debt issuances, commencing at the beginning of the test period subsequent to the test period in which the long-term debt to which the FDH is associated is issued. The combination of the amortization of the DMRA and the interest charges on the underlying debt result in the effective yield on the debt at its hedged rate.
DMRA Balance	The balance in the DMRA at the report date.

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix T

Depreciation Study

2021 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES
APPLICABLE TO ASSETS IN SERVICE

August 2021

Prepared for BC Hydro

Headquarters
293 Boston Post Rd West, Ste 500
Marlborough, MA, USA 01752
508.263.6200

Washington, D.C. Office
1300 19th St NW, Ste 620
Washington, DC, USA 20036
202.587.4470

Concentric Advisors, ULC
200 Rivercrest Drive SE, Ste 277
Calgary, AB, Canada T2C 2X5
403.257.5946

August 12, 2021

BC Hydro and Power Authority
6911 Southpoint Dr
Burnaby, BC
V3N 4X8

Attention: David Wong,
Executive Vice President, Finance, Technology, Supply Chain and CFO;

Ryan Layton,
Chief Accounting Officer;

Dear David and Ryan,

Pursuant to your request, we conducted a review and assessment of the regulated life estimates related to the BC Hydro assets as of March 31, 2020. Our report presents a description of the methods used in the estimation of depreciation and net salvage, the statistical analysis of service life and the summary of annual depreciation expense.

We gratefully acknowledge the assistance of BC Hydro personnel in the completion of the review.

Should you have any questions or concerns, please do not hesitate to contact me directly at 587.997.6489

Yours truly,

Concentric Advisors, ULC

Larry E. Kennedy
Senior Vice President

LEK/ta
Project: 70072

Suite 277 • 200 Rivercrest Drive SE • Calgary, Alberta T2C 2X5 • 403.257.5946• www.ceadvisors.com

TABLE OF CONTENTS

SECTION 1

1 STUDY HIGHLIGHTS

Pursuant to BC Hydro's ("BC Hydro" or the "Company") request, Concentric Advisors, ULC ("Concentric") conducted a depreciation study related to the electric generation, electric transmission, electric distribution, and general plant accounts, as of March 31, 2020.

The purpose of this study was to:

- determine the average service lives and whole life annual accrual percentages related to the return of original cost and cost of removal for ratemaking objectives based on assets in-service at March 31, 2020.
- review the impact of dismantling costs in compliance with the directives 39 and 40 contained in the British Columbia Utilities Commission (BCUC) Decision and Order G-246-20 dated October 2, 2020.

The depreciation study considered three key topics:

- Determination if the current average service life estimates are providing an appropriate return of investment over the useful life of the assets, and provides recommendation for accounts where it is considered that the current average service life estimates require adjustment;
- Review of the current BC Hydro method of collecting Costs of Removal (Dismantling) and consider alternatives for the collection of Dismantling costs in a way that neither current or future ratepayers are overburdened.
- Review and determination of any asset groups that would benefit from the use of a Life Span (Economic Life) approach.

The consideration of the above topics included preparation of detailed historic retirement and cost of removal patterns, in depth discussion with internal BC Hydro subject matter experts and management staff, and a review of Canadian peer electric generation, transmission and distribution utilities.

Based on the above review of the three key topics, Concentric recommends the average service lives and positive salvage rates set forth herein applied specifically to assets in service, as of March 31, 2020, as summarized in Tables 1, 2, and 3 in Section 5 of this report by account detail. Supporting data and calculations are provided as well.

Additionally, Concentric recommends that the estimated future cost of removal requirements be recovered through implementation of the "Traditional Method" of net salvage recovery. Our review and recommendations are discussed in detail in the document entitled "BC HYDRO – Report on Applicability of Inclusion of Net Salvage in the Depreciation Rate Calculations".

This study results in average service life and positive salvage rate proposals that show an estimated average decrease to depreciation expense over a 10-year period, fiscal 2022 to fiscal 2031, of $5.2 million, which excludes the location specific assets subject to the Life Span (Economic Life) approach. This estimated decrease is calculated on the application of the proposed average service lives when applied to the depreciable plant study balances as at March 31, 2021. In addition, the results of the recommended life changes to the location specific assets subject to the Life Span (Economic Life) approach is estimated to be an average $2.3 million increase over the 10-year period, fiscal 2022 to fiscal 2031.

Additionally, in order to provide the impact of the inclusion of dismantlement costs into the depreciation rate calculations, BC Hydro has estimated that the implementation of the estimated future net salvage requirements would result in an additional of $87.8 million, $92.2 million, and $97.5 million of annual net salvage amortization in fiscal years 2023, 2024, and 2025 respectively. However, Concentric notes that this additional annual accrual amount would be offset resulting from the reduction of approximately $53.3 million, $46.3 million, and $44.8 million related to fiscal years 2023, 2024, and 2025, respectively, of current revenue requirement resulting from the current policy of expensing net salvage amounts in the year of occurrence. However, given the potential impact on customer rates, Concentric recommends deferring implementation of the recommended approach for the recovery of the estimated Costs of Removal into depreciation calculation until the next Rate Application in 2026.

1.1 BASIS OF STUDY

1.1.1 Scope

Concentric has been retained by BC Hydro to develop reasonable and appropriate average service life and net salvage percentage estimates for use in the estimated depreciation calculations for the purpose of determining the annual regulated revenue requirement. The review included the analysis based on plant in service as of March 31, 2020 and resulting impacts of the results of this study were applied specifically to plant in service as of March 31, 2020. This report sets forth the findings of our independent review. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates.

The results of this study will be implemented on an individual asset level within the BC Hydro accounting system on a remaining life basis. This is a continuation of the longstanding accounting practice of BC Hydro. Concentric notes that original cost amounts within the BC Hydro accounting system have been reset to the then existing net book value during two separate International Financial Reporting Standards ("IFRS") based implementations. Within these implementations, the net book value of the asset amounts were not changed, however the original cost was reset to the then existing net book value and the accumulated depreciation balances were reset to zero. As such, the continued use of the remaining life calculations applied to each specific asset is reasonable and continues to be the appropriate method of depreciation expense calculation. As these calculations are performed internally within the BC Hydro SAP system, this report does not include depreciation rate calculations.

The Straight-Line method, Average Life Group ("ALG") procedure, applied on a remaining life basis as used within the BC Hydro SAP system is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America and for most regulated utilities in the province of British Columbia. While Concentric notes that this calculation method is usually applied on an account basis, the calculations as applied within the BC Hydro systems on an individual asset basis provides the same calculation basis and Concentric recommends its continued use.

As part of this study, Concentric Advisors reviewed the operating considerations and typical asset configurations throughout the BC Hydro system, through the completion of detailed operational staff discussions. Due to the ongoing COVID-19 pandemic at the time of the completion of this study, site tours were unable to be carried out.

2 PLAN OF STUDY

This study is presented in the following order:

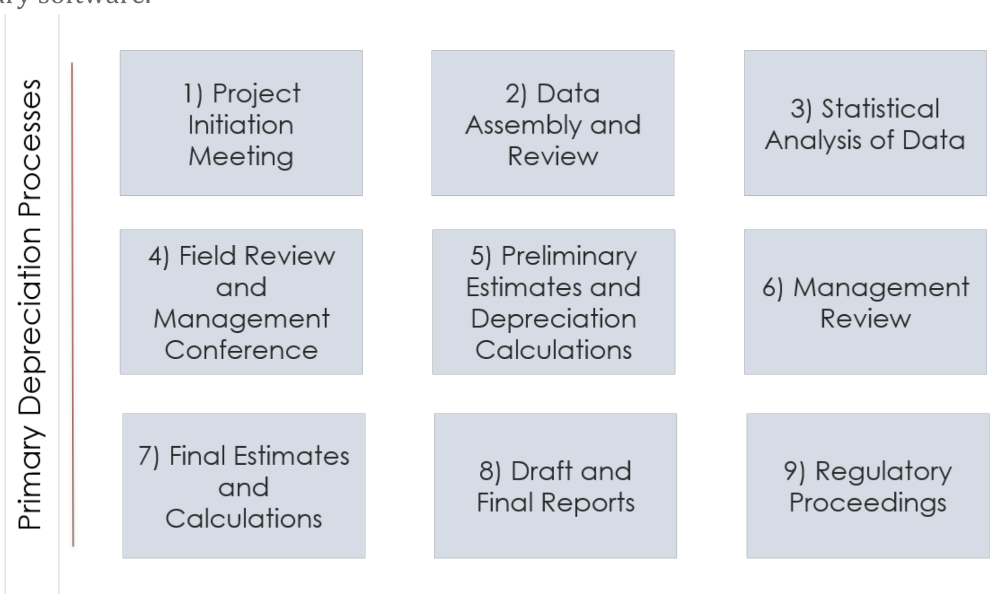
Section 1:	Study Highlights, presents a brief summary of the depreciation study and results
Section 2:	Contains statements with respect to the plan and the Basis of the Study
Section 3:	Development of the Required Average Service Life and Net Salvage Estimates, presents descriptions of the methods used and factors considered in the service life and net salvage studies
Section 4:	Results of Study, presents summaries by depreciable group of annual depreciation in Tables 1, 2, and 3
Section 5:	Estimation of Survivor Curves, is an overview of Iowa curves and the Retirement Rate Analysis
Section 6	Presents the results of the Net Salvage Study

2.1 Depreciation

A full and comprehensive depreciation study includes the following components:

1. supported recommendations regarding Average Service Life estimates for each account;
2. supported recommendations regarding estimated Net Salvage requirements for each account; and
3. a document explaining the procedures followed and justifying the results in a format suitable for submission to senior management and regulatory authorities.

A diagram of the nine primary processes followed by Concentric in the development of the depreciation study is provided below. Each of the steps is undertaken by Concentric using proprietary software.



2.2 Information Provided by BC Hydro

BC Hydro has provided Concentric with required information, as of March 31, 2020, for all accounts being studied. This information has been compiled from the plant accounting records and includes the following:

- current balances by vintage year for each account (aged balances). The balances provide the amount of investment sorted by installation year currently in operation. This file is only inclusive of current plant in service and does not include any retirement information; and
- retirement transactions for all accounts. The transactions include information regarding the transaction year of the retirement, the installation year of the asset being retired, and the original cost of the asset being retired.
- cost of removal (dismantling) and gross salvage transactions requiring the recovery of net salvage through March 31, 2020. The transactions include information regarding the transaction year of the retirement, the costs associated with the retirement, and any gross salvage proceeds from the sale or reuse of the property.

2.3 Procedures Performed

The above data was reviewed and reconciled to Company control schedules to ensure accuracy and reasonableness. These checks include that the surviving investment by account equals (or can be reconciled to) the Company's gross plant in service and accumulated depreciation ledger balances. In addition, Concentric performed the following procedures to form the basis of the results of this study:

- confirm accounting policies being followed in accordance with International Financial Reporting Standards principles;
- conduct interviews with BC Hydro personnel to obtain understanding of company operations;
- completed an actuarial analysis for all depreciable accounts; and
- comparison against industry peers that operate facilities similar to BC Hydro's regulated hydro fleet.

3 DEVELOPMENT OF DEPRECIATION RATES

3.1 Depreciation

Depreciation, as applied to depreciable assets, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of assets in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities, and, in the case of electric companies, the exhaustion of natural resources.[1]

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a time period by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric utility service. Normally, the time over which the fixed capital cost is allocated to the cost of service, is equal to the time over which an item renders service – that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight-Line method of depreciation.

BC Hydro continues to determine depreciation using the Straight-Line method for all plant comprising regulated assets, based on the Average Life Group Procedure – Remaining Life Technique. The Average Life Group Procedure is the most commonly used depreciation procedure for North American utilities, whereby one average service life estimate is applied to all assets and vintages within the asset class. The Remaining Life Technique calculates depreciation on the basis of recovering the net book value of the investment over the remaining life of an asset, or group of assets, with no provision for separate accumulated depreciation true-up. As such, a common life and salvage estimate is applied to each of the assets. Concentric finds the application of the Straight-Line method and the Average Life Group Procedure – Remaining Life Technique results in a reasonable recovery of BC Hydro's capital investment over time and recommends their continued application.

3.2 Estimation of Average Service Life and Net Salvage

3.2.1 Average Service Life

The use of an average service life or a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. The Iowa

[1] Federal Energy Regulatory Commission -Part 201- Uniform System of Accounts Prescribed for Electric Companies Subject to the Provisions of the Electric Act Definitions

curves *"…were sorted into three groups according to whether the mode was to the left, approximately coincident with, or to the right of the average-life ordinate. The curves in each of these three groups were then sub-classified in accordance with the height of the mode, taking also into consideration the distance of the mode to the left or right of the average life."* [2] The Iowa curves are described as L-type (i.e. left-moded), R-type (i.e. right-moded), and S-type (i.e. symmetrical). Further development resulted in the introduction of O-type (i.e. origin-moded curves) where the greatest frequency of retirement occurs at the origin, or immediately after age zero. Individual type curves are further depicted with numerical subscripts which represent the relative heights of the modes of the frequency curves within each family.

The program that is used by Concentric for statistical smooth curve fitting utilizes an internal "goodness-of-fit" criterion known as the Residual Measure. This Residual Measure is based on a least squares solution of the differences between the stub curve (or original data points) and smooth survivor curve which also requires a balancing of the differences above and below the stub curve.

The criterion of goodness-of-fit is the mean square of the differences between the points on the stub and fitted smooth survivor curves. The residual measure, or standard error of estimate, shown in the output format is the square root of this mean square. As such, the lower the Residual Measure the better the statistical fit between the analyzed Iowa curve and the observed data points. Concentric follows the widely used practice of fitting Iowa curves up to one percent of the maximum exposures. This standard practice is utilized to minimize the influence of typically small retirements applied to similarly small exposures which may unduly affect the Iowa curve fitting process. However, Concentric will recognize the observed data points beyond the one percent of maximum exposures if it is determined that the additional data is a valid consideration for life recommendation.

A discussion of the general concept of survivor curves and retirement rate method is presented in Section 7.

3.2.2 Survivor Curve Judgements

The service life used in the depreciation and amortization calculations were based on informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the service life estimates from Concentric's studies of other electric utilities. The use of survivor curves, to reflect the expected dispersion of retirement, provides a consistent method of estimating depreciation for assets. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data and the probable future. Probable future expectations included management and operational staff interviews. The combination of the historical experience and the probable

[2] Robley Winfrey, Statistical Analyses of Industrial Property Retirements, Bulletin 125 revised (Engineering Research Institute, Iowa State University, 1935) 65

future expectations yielded estimated survivor curves from which the average service lives were derived.

The resultant depreciation rates are summarized in the applicable tables of this study (Section 4). The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity.

3.2.3 Operations Discussions

Discussions with operations representatives undertaken as part of this study provided Concentric with an understanding of the type of assets in service for the electric system. These discussions provide Concentric with the necessary background to make an assessment of the physical installations of the BC Hydro plant, and to understand the type of plant in service and the operating conditions of the facilities.

Operational interviews were undertaken to understand the historic operating conditions that have led to retirement of plant in the past and to understand the current condition of the assets which may impact future retirement plans. Operational interviews covered the following topics:

- Operating history of assets in service;
- Replacement history of major asset components and review of any significant retirement programs;
- General operating experience of the major asset components;
- Review of any life restricting operational issues;
- Review of instances where advancements in technology may cause changes to average service life indications; and
- Discussions of the manner in which BC Hydro's assets may differ from peer assets.

3.2.4 Peer Analysis

In order to provide a comparison for each account grouping, Concentric selected a peer group of companies to use in the development of average service lives. The companies selected for comparison were all companies for which Concentric has recently completed depreciation studies relating to Canadian electric generation, transmission, and/or distribution plants. As such, Concentric was able to make a meaningful comparison giving consideration to factors such as, capitalization and retirement policies, maintenance practices, and general operational practices. The companies selected for comparison were:

- Ontario Power Generation;
- Manitoba Hydro;
- Newfoundland and Labrador Hydro Corporation (NALCOR);
- FortisBC Energy; and
- New Brunswick Power.

The above utilities provided Concentric Advisors with a comparable base of average service life estimates to use in the development of the service life estimates for BC Hydro's hydroelectric asset classes through Concentric's professional judgement.

3.2.5 Professional Judgement

The use of professional judgment in the development of average service life estimates is a practice that is appropriate and has been used for many years in North American regulatory jurisdictions. When available, the use of statistical analysis of the historic retirement transactions combined with the use of professional judgment, which includes review of accounting procedures and practices, use of operational staff interviews, review of prior studies, and review of the approved life estimates of peer companies, provides the most complete method of service life analysis.

3.2.6 Life Span Dates

Life expectancy of electric generation and substation plant assets is impacted not only by physical wear and tear of the assets but also by economic factors including the feasibility of the economic replacement of major operating components or the economic viability of the plant as a whole. In circumstances where the replacement of major operating components is not economically feasible, the life of the major component can be the determining factor of the generation and substation plant and all of the assets within the plant. As such, the remaining depreciation life of electric generation and substation plant assets is the lesser of the physical life expectation of the asset or the period to the end of the life span of the generation or substation plant.

The use of life span dates for determining depreciable lives for regulated electric generation plant is common throughout many North American regulatory jurisdictions. The basis for the determination of the life span date is usually based on one or more of the following:

- the physical life estimation of the major and vital components of the generating and substation plant;
- the duration of operating licenses;
- precedent and policy of the regulatory jurisdiction;
- expiration of the supply source for which the generation plant is dependent; and
- expiration of market demand upon which the generation plant is dependent.

The majority of BC Hydro's regulated hydroelectric stations do not require an end of life date as there are currently no factors reasonably expected to limit their life. With regular maintenance and replacement of components, hydroelectric stations, including associated civil structures, are typically expected to operate for very long periods.[3]

The Burrard Synchronous Condense Facility is expected to be removed from service in fiscal year 2025. As such, it has been assigned a four-year remaining life and all assets included at the Burrard

[3] Although dams can be considered a life-limiting component for hydroelectric generating facilities, in practice this does not result in an establishment of a specific life span date as the dams are expected to be in use for the foreseeable future with regular maintenance.

Synchronous Condense Facility are depreciated at 25 percent of the net book value as at March 31, 2021.

The following sites have economic planning horizons assigned due to upcoming terminal retirements:

Site	Economic Planning Horizon	Remaining Life as of March 31, 2020
Balfour	2023	3
Coquitlam	2022	2
Dal Grauer	2035	15
Fairmont	2024	4
Fort Steele	2022	2
George Dickie	2023	3
Glenmore	2024	4
Horne Payne	2025	5
Lougheed	2024	4
Murrin	2035	15
Murrin #1 Dal Grauer Circuit	2033	13
Norgate	2024	4
Quesnel	2022	2
Richmond	2024	4
Scott Road	2023	3
Sumas Way	2024	4
Surrey	2022	2
Wilsey Dam	2029	9

We recommend the locations in the above table be all depreciated on a remaining life basis incorporating the above life-span dates. The net book value of all assets located within these sites are depreciated at a rate of 1/Remaining Life Span.

3.3 Account Reorganization

Concentric reviewed the account structure currently being used by BC Hydro to find accounts where duplication may exist. This was done to ensure efficiency within the accounting practices and reduce regulatory burden. While the combination and reorganization of these accounts will streamline the accounting process, Concentric understands that there may be a large amount of work to input these new accounts and accurately transfer assets between accounts. As such, while Concentric is recommending the transfer of assets into the following account structure within the test period of this depreciation study, the depreciation study is being submitted with the currently approved account structure.

VEHICLE ACCOUNTS

2020 Plant in Service	Previously Approved Life	Concentric Recommended Life
$255,207,136	Varies	Varies

The assets in these accounts relate to vehicle fleet owned by BC Hydro. These assets are a variety of sizes and types and have a variety of expected lives. Through the completion of the depreciation study, Concentric was made aware that the currently utilized account structure for vehicles was leading to non-homogeneous assets being grouped together. Consequently, vehicles were retired before the expected end of life and/or with lower than expected proceeds per the asset class, leading to losses on retirement. Concentric recommends BC Hydro examine the vehicles accounts and create a set of accounts that better aligns with the actual use of vehicles assets. In discussion with BC Hydro operations and management, Concentric recommends the following account structure be created:

Account Name	Assets Included	Proposed Asset Life	Proposed Net Salvage
Light Vehicles	Automobiles SUVs Cargo and cutaway vans Pick-up trucks one ton and under	10	15%
Medium Vehicles	Service Body trucks Flat Deck trucks	10	9%
Walk-in Van	Walk-in Vans	12	9%
Bucket Trucks > 50’	Bucket Trucks >50’	14	5%
Bucket Trucks 40 – 50’	Bucket Trucks 40-50’	12	5%
Bucket Trucks < 40’	Bucket Trucks < 40’	10	5%
Heavy Digger Derrick and Fire Truck	Heavy Digger Derrick Fire Truck	15	5%
Heavy Flat Deck, Dump Trucks, Highway Tractors	Heavy Flat Deck Dump Trucks Highway Tractors	12	5%
Trailers	Trailers	15	17%
Equipment	Snow vehicles Sweeper	16	7%

	Loader/Backhoe Ride-Rails Forklift / Pallet Jack Other Equipment (e.g., mobile welder and compressor)		

As the above accounts have not received approval from the British Columbia Utilities Commission, Concentric recommends the following lives be utilized until the new account structure can be created. Upon approval of the updated account structure and the creation of new accounts, Concentric recommends that the following accounts be closed:

Account Number	Account Description	Currently Approved Life	Currently Approved Net Salvage	Proposed life	Proposed Net Salvage
C81001	Automobiles	8	20%	10	15%
C81101	Trucks < 1 Ton 2 Wheel Drive	8	20%	10	15%
C81201	Trucks < 1 Ton 4 Wheel Drive	8	20%	10	15%
C81301	Trucks > = 1 Ton 2 Wheel Drive	13	15%	10	9%
C81302	Truck > = 1 Ton 2 Wheel Drive	13	5%	10	9%
C81401	Trucks > = 1 Ton 4 Wheel Drive	13	25%	12	5%
C81501	Trucks > = 1 Ton 6 Wheel Drive	12	10%	14	5%
C81601	Tractor, Highway	9	10%	12	5%
C81701	Aerial Device	13	10%	12	5%
C81702	Line / Service / Van Body	15	15%	10	9%
C81703	Derricks / Diggers	15	20%	15	5%
C81704	Ride-A-Rails	25	15%	16	7%
C82501	Forklift / Pallet Jack	20	20%	16	7%
C82502	Snow Vehicle	20	40%	15	10%

C82503	Sweeper	15	15%	16	7%
C82504	Loader / Backhoe	17	45%	16	7%
C82505	Trailer, Reel / Pole / Utility	20	10%	18	10%
C82506	Welder, Mobile, Self-Powered	15	15%	15	10%
C82507	Compressor, Mobile, Self-Powered	15	10%	15	10%

3.4 Net Salvage Estimates

Concentric is aware of BCUC directives 39 and 40 to review the impact of dismantling costs contained in the British Columbia Utilities Commission (BCUC) Decision and Order G-246-20 dated October 2, 2020. As such, Concentric has completed a review of different net salvage recovery mechanisms used throughout North America and the applicability of these mechanisms to the BC Hydro system. The results of this review are attached in the document entitled "BC HYDRO – Report on Applicability of Inclusion of Net Salvage in the Depreciation Rate Calculations". In this report, Concentric recommends the traditional approach to net salvage applied on a functional group basis.

The net salvage estimates used in the depreciation calculations were based on informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the net salvage estimates from Concentric's studies of other electric utilities.

The estimates of net salvage for the mass property accounts were based in part on historical data related to actual retirement activity for the years 2011 through 2020 at the functional group level. Gross salvage and cost of removal and related to experienced retirements were used. Given that the historic data was available at an aggregated functional level, Concentric recommends that the net salvage percentage be determined at a functional level as follows:

- Generation accounts;
- Transmission accounts;
- Distribution accounts;
- General Plant accounts;
- Vehicle accounts.

In the development of the estimated net salvage percentage for each of the above functional groups, Concentric removed specific accounts that would not be expected to incur costs of removal or retirement, and any assets with an existing Asset Retirement Obligation ("ARO").

Percentages of the cost of plant retired were calculated for each component of net salvage on an annual, three-year, five-year, and on a cumulative moving average basis. The same net salvage percentage was applied to all assets within the same functional group for accounts within the group that would be expected to incur costs of removal or retirement.

3.5 Average Service Life Assessments

Concentric has reviewed the average service life estimates for BC Hydro's asset categories, based on March 31, 2020 asset values.

The following discussion, dealing with a number of accounts which comprise the majority of the investment analyzed, presents an overview of the factors considered by Concentric in the determination of the average service life estimates. The survivor curve estimates for the remainder of the accounts not discussed in the following sections were based on similar considerations.

ACCOUNT C11650 – CONTRIBUTIONS – INFRASTRUCTURE RIGHTS

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$6,259,569	0.02%	35	35-SQ

The assets in this account relate to contributions made related to the assets in Account C52201 – Distribution, Transformers. Consequently, the life of this account should be tied to the life of Account C52201. As such Concentric is recommending an Iowa 35-SQ to match the life of Account C52201.

ACCOUNT C22005 – BUILDING, COMPOSITE POOL

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$561,958,586	1.99%	60	65-R3

The assets in this account relate to electric reliability focused buildings throughout British Columbia. These buildings are typically built out of cinder blocks in a variety of styles based on when the buildings were built and the purpose of the building.

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2011 through 2020 of $12,551,395 were recorded and have resulted in actual observed data points as depicted on page 5-43. The best fitting Iowa Curve using the currently approved 60-year life is the Iowa 60-R5 with a residual measure of 0.3136. An Iowa 65-R3 provides a better visual fit with a residual measure of 0.4645. A review of peer Canadian electric utilities provides a range from 50 years to 75 years. Based on the above and on Concentrics' experience, an Iowa 65-R3 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 65-R3 to represent the future expectations for the investment in this account.

ACCOUNT C22007 – BUILDINGS, ENVELOPE

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$170,299,646	0.60%	30	35-R3

The assets in this account relate to the outer building envelope related to buildings throughout British Columbia. This includes assets such as doors, windows, siding, structural masonry, and insulation.

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2011 through 2020 of $476,562 were recorded and have resulted in actual observed data points as depicted on page 5-48. Peer utilities do not typically have an account with the envelope related assets alone. Consequently, the assets in this account tend to have longer lives in peer utilities and therefore, the peer review is of limited value. As there have been minimal retirements in the preceding nine years, Concentric views that a slight life extension is warranted at this time. Based on the above and on Concentrics' experience, an Iowa 35-R3 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 35-R3 to represent the future expectations for the investment in this account.

ACCOUNT C22009 – BUILDINGS, HVAC SYSTEMS AND COMPONENTS

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$101,296,784	0.36%	15	20-R3

The assets in this account relate to the heating, ventilation, and air conditioning ("HVAC") systems located in buildings throughout British Columbia.

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2011 through 2020 of $1,568,375 were recorded and have resulted in actual observed data points as depicted on page 5-51. The best fitting Iowa Curve using the currently approved 15-year life is the Iowa 15-R4 with a residual measure of 0.1335. An Iowa 20-R3 provides a better residual measure of 0.0869. Peer utilities do not typically have an account with the HVAC related assets alone. Consequently, the assets in this account tend to have longer lives in peer utilities and therefore, the peer review is of limited value. Based on the above and on Concentrics' experience, an Iowa 20-R3 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 20-R3 to represent the future expectations for the investment in this account.

ACCOUNT C23201 – PENSTOCK, STEEL

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$410,680,827	1.46%	75	85-R4

The assets in this account relate to the steel penstocks located in hydroelectric generation sites. The majority of penstocks on the BC Hydro system are steel. Most steel penstocks have a coating.

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. There were no retirements recorded between 2011 and 2020. As such, the actuarial analysis is of limited value. A review of peer Canadian electric utilities provides a range from 60 years to 90 years; however, there is often a mix of materials in the penstock account. Therefore, it is expected that there may be some divergence in the life of this account between different utilities. As there have not been any retirements in the preceding nine years, Concentric views that a life extension is warranted at this time. Based on the above and on Concentrics' experience, an Iowa 85-R4 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 85-R4 to represent the future expectations for the investment in this account.

ACCOUNT C23202 – PENSTOCK, CONCRETE

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$85,009,389	0.30%	100	85-R4

The assets in this account relate to the concrete penstocks located in hydroelectric generation sites. The majority of penstocks on the BC Hydro system are steel. Most concrete penstocks have a coating, however none of the coatings are polyethylene.

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. There were no retirements recorded between 2011 and 2020. As such, the actuarial analysis is of limited value. A review of peer Canadian electric utilities provides a range from 60 years to 90 years; however, there is often a mix of materials in the penstock account. Therefore, it is expected that there may be some divergence in the life of this account between different utilities. Based on the above and on Concentrics' experience, an Iowa 85-R4 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 85-R4 to represent the future expectations for the investment in this account.

ACCOUNT C23801 - CRANES

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$115,886,373	0.41%	60	65-R4

The assets in this account relate to powerhouse and gantry cranes, located on the BC Hydro generation dams. These assets are typically long lived with minimal modernization required.

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2012 through 2020 of $5,387,660 were recorded and have resulted in actual observed data points as depicted on page 5-100. The best fitting Iowa Curve using the currently approved 60-year life is the Iowa 60-R3.5 with a residual measure of 0.2036. An Iowa 65-R4 provides a residual measure of 0.3377. A review of peer

Canadian electric utilities provides a range from 55 years to 70 years. Based on the above and on Concentrics' experience, an Iowa 65-R4 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 65-R4 to represent the future expectations for the investment in this account.

ACCOUNT C24301 – SLOPE STABILIZATION

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$163,033,255	0.58%	100	70-R3

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2013 through 2020 of $2,503 were recorded and have resulted in actual observed data points as depicted on page 5-124. As the level of retirements is minimal, the actuarial analysis is of limited value. Peer utilities do not typically have an account with slope stabilization assets alone. Consequently, the peer review is of limited value. Discussions with BC Hydro operations staff indicate that the life of this account should decrease due to the life decreases in similar accounts. At this time, Concentric recommends an Iowa 70-R3 to represent the future expectations for the investment in this account.

ACCOUNT C25101 – STRUCTURE, SUPPORT, STEEL

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$184,451,646	0.65%	65	55-R4

The assets in this account relate to buildings throughout British Columbia. BC Hydro has been working to replace wood buildings with steel buildings where appropriate.

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2013 through 2020 of $1,475,173 were recorded and have resulted in actual observed data points as depicted on page 5-131. The best fitting Iowa Curve using the currently approved 65-year life is the Iowa 65-R5 with a residual measure of 0.2535. An Iowa 55-R4 provides a residual measure of 0.4445. A review of peer Canadian electric utilities provides a range from 55 years to 65 years. Based on the above and on Concentrics' experience, an Iowa 55-R4 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 55-R4 to represent the future expectations for the investment in this account.

ACCOUNT C41007 – TURBINE, HYDRO, COMPOSITE POOL

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$415,468,606	1.47%	50	55-R3

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2013 through 2020 of $462,118 were recorded and have resulted in actual observed data points as depicted on page 5-232. The best fitting Iowa Curve using the currently approved 50-year life is the Iowa 50-R5 with a residual measure of 0.4982. An Iowa 55-R3 provides a residual measure of 0.6834. Historical data indicates that a life as long as 100 years may be appropriate; however, Concentric believes that an extension in life of 100 percent is not warranted at this time. A review of peer Canadian electric utilities provides a range from 55 years to 70 years. Based on the above and on Concentrics' experience, an Iowa 55-R3 is a reasonable expectation for the investment in this account. This account will require close monitoring in future depreciation studies, and possibly a future life extension if the data continues to show that such an extension is warranted. At this time, Concentric recommends an Iowa 55-R3 to represent the future expectations for the investment in this account.

ACCOUNT C42001 – COILS, STATOR

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$207,996,660	0.74%	30	35-R3.5

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2012 through 2020 of $9,372,606 were recorded and have resulted in actual observed data points as depicted on page 5-243. The best fitting Iowa Curve using the currently approved 30-year life is the Iowa 30-R5 with a residual measure of 0.7352. An Iowa 35-R3.5 provides a better residual measure of 0.421. Peer utilities do not typically have an account with coil assets alone. Consequently, the peer review is of limited value. Based on the above and on Concentrics' experience, an Iowa 35-R3.5 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 35-R3.5 to represent the future expectations for the investment in this account.

ACCOUNT C52202 – DISTRIBUTION, CUT OUTS

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$58,991,451	0.21%	25	35-R0.5

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2013 through 2020 of $15,731,969 were recorded and have resulted in actual observed data points as depicted on page 5-319. The best fitting Iowa Curve using the currently approved 25-year life is the Iowa 25-L0 with a residual measure of 0.2713. An Iowa 35-R0.5 provides a residual measure of 0.7625. Peer utilities do not typically have an account with cut outs alone. Consequently, the peer review is of limited value. Based on the above and on Concentrics' experience, an Iowa 35-R0.5 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 35-R0.5 to represent the future expectations for the investment in this account.

ACCOUNT C54102 – BREAKER, GAS (Sf6) 12 / 25 kV

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$178,778,377	0.64%	30	35-R3

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2011 through 2020 of $1,751,155 were recorded and have resulted in actual observed data points as depicted on page 5-371. The best fitting Iowa Curve using the currently approved 30-year life is the Iowa 30-R3.5 with a residual measure of 0.0775. An Iowa 35-R3 provides a residual measure of 0.0843. Peer utilities typically group all breakers into a single account. Consequently, the peer review is of limited value. Discussions with BC Hydro operations staff indicate that the life of this account should increase due to the life increases in similar accounts. At this time, Concentric recommends an Iowa 35-R3 to represent the future expectations for the investment in this account.

ACCOUNT C55101 – CONDUCTOR, OVERHEAD > OR = 60 kV

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$749,347,904	2.66%	60	55-R3

The assets in this account relate to overhead transmission conductor. There is currently a replacement program related to 69 kV copper conductor located primarily in urban areas. This replacement program is on the scale of $2 million to $3 million per year. Discussions with operations staff indicated that the life for these assets should be at least as long as the life of poles. Concentric has recommended maintaining the currently approved life of transmission pole structures at 50 years. Additionally, it is expected that transmission conductor should have a longer life than distribution conductor.

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2013 through 2020 of $10,980,174 were recorded and have resulted in actual observed data points as depicted on page 5-399 with a residual measure of 0.4188. An Iowa 55-R3 provides a residual measure of 0.6568. A review of peer Canadian electric utilities provides a range from 45 years to 85 years. Based on the above and on Concentrics' experience, an Iowa 55-R3 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 55-R3 to represent the future expectations for the investment in this account which aligns with the views expressed by operations staff

ACCOUNT C55102 – CONDUCTOR, OVERHEAD < 60 kV

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$782,029,570	2.78%	45	50-R1

The assets in this account relate to approximately 48,000 kilometers of distribution overhead conductor. This conductor is more commonly installed in rural areas of the province and is subject to damage due to motor vehicle accidents as well as damage caused by storms. Prior to 2004, automatic splices were used to connect or repair distribution overhead conductor which resulted in some premature failures. However, since 2004 compression splices have been used which do not have the same risk of premature failure. One of the major drivers of retirement in this account are system improvement and capacity growth projects. Based on discussions with operations staff BC Hydro believes these assets should have a similar life as distribution wood pole structures. Concentric has recommended maintaining the currently approved life of distribution pole structures at 50 years. Due to its normally smaller conductor sizes, it is expected that distribution overhead conductor should, in general, have a shorter life than transmission overhead conductor. Concentric has recommended lengthening the life of distribution overhead conductor to 50 years.

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2013 through 2020 of $37,784,836 were recorded and have resulted in actual observed data points as depicted on page 5-403. The best fitting Iowa Curve using the currently approved 45-year life is the Iowa 45-R5 with a residual measure of 0.4828. An Iowa 50-R1 provides a residual measure of 0.8209. A review of peer Canadian electric utilities provides a range from 45 years to 60 years. Based on the above and on Concentrics' experience, an Iowa 50-R1 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 50-R1 to represent the future expectations for the investment in this account.

ACCOUNT C55401 – BUSWORK & STATION CONDUCTOR

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$422,095,765	1.50%	60	55-R4

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2013 through 2020 of $6,621,634 were recorded and have resulted in actual observed data points as depicted on page 5-430. The best fitting Iowa Curve using the currently approved 60-year life is the Iowa 60-R4 with a residual measure of 0.0464. An Iowa 55-R4 provides a residual measure of 0.0836. A review of peer Canadian electric utilities provides an estimate of 50 years. Based on the above and on Concentrics' experience, an Iowa 55-R4 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 55-R4 to represent the future expectations for the investment in this account.

ACCOUNT C59001 – POWER SUPPLY, UNINTERUPTIBLE

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$4,440,828	0.02%	15	5-SQ

The assets in this account relate to power units supporting the corporate network. These are between one and six kV in size and are retired on a three to five-year schedule. Consequently, the life of these assets is dependent on management discretion surrounding the retirement policy. As such, Concentric recommends utilizing amortization accounting for these assets with a life equal to the longest retirement period. Based on the above and on Concentric's experience, an Iowa 5-SQ is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 5-SQ to represent the future expectations for the investment in this account.

ACCOUNT C59202 – ELECTRIC VEHICLE CHARGING STATION

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$0	0.00%	N/A	7-R3

The assets in this account relate to the upcoming Electric Vehicle Direct Current Fast Charging Program. These assets are located downstream of the electric service and consist solely of the battery charger system. These assets are highly technological in nature and are subject to the fast-paced nature of retirements common in technological accounts. As many of the forces of retirements anticipated in this account are related to the pace of change of technology, it is important that this account have a short average service life. There are few peer utilities in Canada with approved lives for electric vehicle charging stations; however, Concentric has carried out discussions with personnel at many utilities across Canada in anticipation of upcoming technological changes. It is the experience of Concentric that the assets included in this account are expected to live approximately five to ten years. As such, Concentric recommends an Iowa 7-R3 to represent the future expectations for the investment in this account.

ACCOUNT C59301 – STORAGE BATTERIES, BANK

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$33,649,647	0.12%	20	15-R4

The assets in this account relate valve regulated lead-acid ("VLRA") batteries which form part of the uninterruptable power source. Conversations with operations and management suggest that the assets in this account are subject to a maximum life of 15 years. Consequently, the life of these assets is dependent on management discretion surrounding the retirement policy.

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2013 through 2020 of $126,840 were recorded and have resulted in actual observed data points as depicted on page 5-458. The best fitting Iowa Curve using the currently approved 20-year life is the Iowa 20-R5 with a residual measure of 0.0498. An Iowa 15-R4 provides a residual measure of 0.7087. While the fit to historical data is not as good with the 15-R4, it is expected that the assets currently in this account will have a shorter life than those in the past. Therefore, the actuarial analysis was afforded limited weighting. A review of peer Canadian electric utilities provides an estimate of 26 years. Based on the above and on Concentrics' experience, an Iowa 15-R4 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 15-R4 to represent the future expectations for the investment in this account.

ACCOUNT C61101 – ALARM / SECURITY SYSTEM

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$65,791,138	0.23%	20	15-R3.5

The assets in this account are related to the security apparatus located on BC Hydro generation, substation and properties (non-energized) sites. These assets tend to be technological in nature, which generally has a life shortening effect. Some examples of assets included are cabling, trenching, access control and management, control panels, sirens, strobes, and cameras. As technology improves, it is expected that the lives of these assets will shorten.

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2012 through 2020 of $10,093,188 were recorded and have resulted in actual observed data points as depicted on page 5-474. The best fitting Iowa Curve using the currently approved 20-year life is the Iowa 20-R0.5 with a residual measure of 0.5688. An Iowa 15-R3.5 provides a residual measure of 0.4311. Peer utilities do not typically have an account with security and alarm assets alone. Consequently, the peer review is of limited value. Based on the above and on Concentrics' experience, an Iowa 15-R3.5 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 15-R3.5 to represent the future expectations for the investment in this account.

ACCOUNT C68302 – RADIO, MICROWAVE, DIGITAL

2020 Plant in Service	Investment %	Previously Approved Life	Concentric Recommended Life
$40,725,868	0.14%	35	20-R3

The assets in this account are related to the operational communication system utilized throughout British Columbia. These assets provide the backbone of the SCADA and protection system and are housed in control buildings. Analogue radio systems were phased out in the early 2000's and replaced by a digital system. The first generation of digital microwave radios were installed in the late 1990's and are currently undergoing replacements. These assets have attained ages of about 22 – 23 years and are being replaced beyond the end of life. It is expected that the technology in these accounts will continue to have a life shortening impact on the average service life going forward.

The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2011 through 2020 of $3,576,344 were recorded and have resulted in actual observed data points as depicted on page 5-516. The best fitting Iowa Curve using the currently approved 35-year life is the Iowa 35-R2 with a residual measure of 2.1121. An Iowa 20-R3 provides a residual measure of 4.5228. While the fit to historical data is not as good with the 20-R3, there has been limited retirements recorded. Therefore, the actuarial analysis was afforded limited weighting for this study. As the first generation of these assets begins to retire, a more relevant retirement dispersion will be evident in future depreciation studies. A review of peer Canadian electric utilities provides an estimate of 8 to 20 years. Based on the above and on Concentrics' experience, an Iowa 20-R3 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 20-R3 to represent the future expectations for the investment in this account.

4 RESULTS OF STUDY

4.1 Qualification of Results

The average service life and net salvage percentage estimates are the principal results of the study and are shown in Tables 1, 2, and 3. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual parameters. An assumption that depreciation parameters can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service.

BC Hydro Power Authority

TABLE 1 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS
RELATED TO UTILITY PLANT AS OF MARCH 31, 2020
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Asset Class #	Description	March 31, 2020 Original Cost	March 31, 2020 Accrued Depreciation	March 31, 2020 Net Book Value	Current Life	Current Curve	Current Positive Salvage Rate	Current Depreciation Expense**	Recommended Life	Recommended Inferred Depreciation Rate**	Recommended Curve	Recommended Positive Salvage Rate	Recommended Net Salvage	Recommended Depreciation Expense for Life**	Change in Depreciation Expense*
C11636	Land Rights, Finite Life, 20 Years	$ 16,974,442	$ (1,996,831)	$ 14,977,611	20	0	0%	$ 896,916	20	5.00%	SQ	0%	1.00	$ 896,916	$ -
C11650	Infrastructure Rights (Contributions - Infrastructure Rights)	$ 6,259,569	$ (163,941)	$ 6,095,628	35	0	0%	$ 2,171	35	2.86%	SQ	0%	1.00	$ 2,171	$ -
C11801	Recreation Facilities	$ 2,102,622	$ (649,852)	$ 1,452,770	20	0	0%	$ 112,717	25	4.00%	R3.5	0%	1.30	$ 76,351	$ 36,367
C11901	Surfacing, Yard	$ 127,629,678	$ (11,736,371)	$ 115,893,307	35	0	0%	$ 4,436,066	40	2.50%	L4	0%	1.05	$ 3,741,464	$ 694,602
C12001	Trail, Caterpillar	$ 127,490	$ (12,217)	$ 115,273	50	0	0%	$ 4,072	50	2.00%	SQ	0%	1.30	$ 4,072	$ -
C12002	Road, Paved / Gravel	$ 177,603,518	$ (10,714,369)	$ 166,889,149	50	0	0%	$ 3,904,123	55	1.82%	SQ	0%	1.05	$ 3,486,286	$ 417,837
C12005	Roads & Trails, Composite Pool	$ 93,627,578	$ (6,930,155)	$ 86,697,422	50	0	0%	$ 2,682,584	55	1.82%	SQ	0%	1.30	$ 2,239,464	$ 443,120
C12101	Tracks, Railway	$ 34,907	$ (5,818)	$ 29,089	40	0	0%	$ 1,939	45	2.22%	SQ	0%	1.10	$ 1,429	$ 510
C12201	Bridge, Wood	$ 7,061,689	$ (936,086)	$ 6,125,603	25	0	0%	$ 369,937	25	4.00%	SQ	0%	1.30	$ 369,937	$ -
C12202	Bridge, Steel	$ 33,572,585	$ (2,169,427)	$ 31,403,158	46	R3	0%	$ 822,482	45	2.22%	SQ	0%	1.30	$ 849,625	$ (27,144)
C12203	Bridge, Concrete	$ 8,741,244	$ (484,676)	$ 8,256,569	75	R2	0%	$ 161,642	75	1.33%	SQ	0%	1.30	$ 161,642	$ -
C12301	Pad, Helicopter	$ 6,243,238	$ (892,724)	$ 5,350,514	25	0	0%	$ 349,299	25	4.00%	SQ	0%	1.05	$ 349,299	$ -
C12401	Drainage System, Yard	$ 31,550,492	$ (2,181,823)	$ 29,368,669	50	0	0%	$ 894,404	50	2.00%	R4	0%	1.00	$ 894,404	$ -
C12402	Landscaping	$ 17,057,566	$ (2,089,683)	$ 14,967,884	25	0	0%	$ 768,945	30	3.33%	R3	0%	1.00	$ 600,457	$ 168,489
C12501	Wall, Retaining, Steel	$ 526,306	$ (40,434)	$ 485,872	50	0	0%	$ 17,040	50	2.00%	R3	0%	1.30	$ 17,040	$ -
C12502	Wall, Retaining, Concrete	$ 15,981,218	$ (448,717)	$ 15,532,501	100	0	0%	$ 176,411	100	1.00%	R3	0%	1.05	$ 176,411	$ -
C21001	Dam, Embankment / Concrete	$ 2,718,570,610	$ (133,151,237)	$ 2,585,419,374	100	R4	0%	$ 54,304,844	100	1.00%	R3	0%	1.00	$ 54,304,844	$ -
C21002	Dam, Crib, Wooden	$ 504,182	$ (137,561)	$ 366,621	35	L3	0%	$ 45,854	35	2.86%	R3	0%	1.00	$ 45,854	$ -
C21101	Dike, Protective	$ 4,850,456	$ (184,288)	$ 4,666,168	100	0	0%	$ 61,429	100	1.00%	R3	0%	1.00	$ 61,429	$ -
C21102	Erosion Donut / Bank Protection	$ 15,627,249	$ (2,260,852)	$ 13,366,397	25	R2	0%	$ 788,148	25	4.00%	R4	0%	1.00	$ 788,148	$ -
C21103	Debris / Avalance Deflector	$ 1,459,576	$ (266,643)	$ 1,192,933	25	0	0%	$ 88,881	25	4.00%	R2	0%	1.30	$ 88,881	$ -
C21901	Roofs	$ 60,228,031	$ (6,932,521)	$ 53,295,510	30	R1.5	0%	$ 2,607,995	35	2.86%	R1.5	0%	1.05	$ 2,080,961	$ 527,034
C22001	Plant, Concrete Or Steel	$ 483,504,413	$ (23,892,880)	$ 459,611,534	50	0	0%	$ 10,587,704	50	2.00%	R3	0%	1.05	$ 10,587,704	$ -
C22002	Commercial, Concrete Or Steel	$ 132,949,119	$ (15,362,071)	$ 117,587,048	50	R2.5	0%	$ 5,608,155	50	2.00%	R3	0%	1.05	$ 5,608,155	$ -
C22003	Powerhouse, Integral With Dam	$ 634,701,833	$ (29,851,839)	$ 604,849,994	100	R4	0%	$ 10,721,939	100	1.00%	R1.5	0%	1.10	$ 10,721,939	$ -
C22004	Building, Wood	$ 15,570,798	$ (4,781,279)	$ 10,789,519	15	R1	0%	$ 1,595,722	20	5.00%	R3	0%	1.05	$ 834,626	$ 761,096
C22005	Building, Composite Pool	$ 562,422,918	$ (40,035,738)	$ 522,387,181	60	R2	0%	$ 14,101,852	65	1.54%	R3	0%	1.05	$ 11,950,551	$ 2,151,301
C22006	Equipment Shelter	$ 14,766,313	$ (5,962,612)	$ 8,803,701	10	R0.5	0%	$ 1,281,734	10	10.00%	R3	0%	1.05	$ 1,281,734	$ -
C22007	Buildings - Envelope	$ 171,079,652	$ (20,773,557)	$ 150,306,096	30	0	0%	$ 7,633,213	35	2.86%	R3	0%	1.05	$ 5,470,100	$ 2,163,113
C22009	Buildings -HVAC Systems & Components	$ 101,609,635	$ (18,012,982)	$ 83,596,653	15	0	0%	$ 8,589,861	20	5.00%	R3	0%	1.05	$ 5,582,743	$ 3,007,118
C22101	Office Trailer / Mobile Home	$ 12,772,542	$ (2,020,889)	$ 10,751,653	23	R1	0%	$ 789,230	25	4.00%	R3	0%	1.05	$ 691,668	$ 97,562
C22211	Leasehold Improvements - 5 Years	$ 1,178,280	$ (1,166,603)	$ 11,678	5	0	0%	$ -	5	20.00%	SQ	0%	1.00	$ -	$ -
C22212	Tenant Improvements - 10 Years	$ 384,957	$ (338,327)	$ 46,631	10	0	0%	$ 259,861	10	10.00%	SQ	0%	1.00	$ 259,861	$ -
C23001	Spillway, Separate From Dam	$ 312,237,586	$ (16,859,414)	$ 295,378,172	75	R2	0%	$ 6,235,365	75	1.33%	R4	0%	1.00	$ 6,235,365	$ -
C23101	Intake Structure, Power	$ 235,462,996	$ (7,530,570)	$ 227,932,426	100	R4	0%	$ 3,127,935	100	1.00%	R4	0%	1.00	$ 3,127,935	$ -
C23201	Penstock, Steel	$ 408,884,961	$ (13,755,286)	$ 395,129,674	75	R4	0%	$ 6,315,096	85	1.18%	R4	0%	1.00	$ 5,333,215	$ 981,881
C23202	Penstock, Concrete	$ 85,009,389	$ (5,118,862)	$ 79,890,527	100	R4	0%	$ 1,890,502	85	1.18%	R4	0%	1.00	$ 3,411,296	$ (1,520,794)
C23203	Penstock, Wood	$ 267,107	$ (101,352)	$ 165,754	50	S3	0%	$ 7,095	50	2.00%	R4	0%	1.00	$ 7,095	$ -
C23204	Penstock - Coatings	$ 27,851,165	$ (3,101,435)	$ 24,749,731	25	0	0%	$ 1,367,835	45	2.22%	SQ	0%	1.00	$ 581,512	$ 786,322
C23302	Tank, Surge, Steel	$ 24,408,455	$ (1,187,962)	$ 23,220,492	50	R3	0%	$ 555,119	50	2.00%	R4	0%	1.10	$ 555,119	$ -
C23401	Tailrace	$ 156,385,018	$ (4,655,433)	$ 151,729,585	100	R3	0%	$ 2,062,036	100	1.00%	R3	0%	1.00	$ 2,062,036	$ -
C23501	Canal	$ 11,721,791	$ (584,721)	$ 11,137,070	100	R3	0%	$ 199,753	100	1.00%	R3	0%	1.00	$ 199,753	$ -
C23601	Stoplogs, Steel	$ 9,442,181	$ (698,327)	$ 8,743,854	60	R3	0%	$ 232,258	50	2.00%	R2	0%	1.00	$ 410,102	$ (177,845)
C23602	Stoplogs, Wood	$ 2,418,161	$ (212,786)	$ 2,205,375	25	0	0%	$ 99,313	50	2.00%	R2	0%	1.00	$ 45,273	$ 54,040
C23603	Hoist, Gate	$ 97,693,824	$ (8,260,298)	$ 89,433,526	55	R4	0%	$ 3,233,242	55	1.82%	R3	0%	1.10	$ 3,233,242	$ -
C23604	Gate	$ 383,682,272	$ (43,941,204)	$ 339,741,067	40	R2.5	0%	$ 16,516,822	45	2.22%	R4	0%	1.10	$ 13,068,633	$ 3,448,189
C23605	Gates, Embedded Components	$ 40,488,664	$ (3,843,604)	$ 36,645,060	40	0	0%	$ 1,277,367	45	2.22%	R4	0%	1.10	$ 1,078,528	$ 198,839
C23606	Inlet Valves, Penstock & Turbines	$ 26,179,742	$ (1,019,790)	$ 25,159,952	50	0	0%	$ 543,005	50	2.00%	R3	0%	1.10	$ 543,005	$ -
C23701	Trash Racks	$ 15,622,302	$ (1,856,496)	$ 13,765,807	50	R2.5	0%	$ 558,923	50	2.00%	R2	0%	1.10	$ 558,923	$ -
C23801	Cranes	$ 115,871,327	$ (8,642,789)	$ 107,228,537	60	R3	0%	$ 3,604,488	65	1.54%	R4	0%	1.10	$ 2,812,923	$ 791,565
C23901	Fishways, Steel	$ 6,196,252	$ (576,871)	$ 5,619,380	50	R2.5	0%	$ 192,290	75	1.33%	R3	0%	1.10	$ 100,386	$ 91,904
C23902	Fishways, Concrete	$ 251,228	$ (8,926)	$ 242,302	100	0	0%	$ 2,087	75	1.33%	R3	0%	1.10	$ 2,985	$ (898)
C24001	Navigation Locks	$ 25,782,700	$ (1,594,262)	$ 24,188,438	100	0	0%	$ 531,444	100	1.00%	R3	0%	1.00	$ 531,444	$ -
C24002	Controls	$ 8,453,423	$ (718,447)	$ 7,734,976	20	0	0%	$ 350,259	20	5.00%	R4	0%	1.10	$ 350,259	$ -
C24003	Motor	$ 27,114	$ (7,022)	$ 20,092	20	0	0%	$ 2,341	20	5.00%	R3	0%	1.10	$ 2,341	$ -
C24101	Sluiceway, Separate From Dam	$ 37,493,964	$ (2,205,261)	$ 35,288,702	100	R3	0%	$ 735,087	100	1.00%	R3	0%	1.00	$ 735,087	$ -
C24201	Tunnels	$ 65,348,911	$ (3,299,365)	$ 62,049,547	100	R4	0%	$ 1,099,788	100	1.00%	R3	0%	1.00	$ 1,099,788	$ -
C24301	Slope Stabilization	$ 163,033,255	$ (4,395,955)	$ 158,637,300	100	0	0%	$ 1,798,854	70	1.43%	R3	0%	1.00	$ 2,820,926	$ (1,022,072)
C24401	Dock / Wharf	$ 1,725,948	$ (173,879)	$ 1,552,068	25	0	0%	$ 94,500	25	4.00%	R4	0%	1.10	$ 94,500	$ -
C24402	Ramp, Boat / Barge	$ 6,541,272	$ (1,148,400)	$ 5,392,871	20	0	0%	$ 382,478	20	5.00%	R3	0%	1.10	$ 382,478	$ -
C25101	Structure, Support, Steel	$ 184,371,497	$ (9,475,955)	$ 174,895,542	65	0	0%	$ 3,675,507	55	1.82%	R4	0%	1.05	$ 4,909,997	$ (1,234,490)
C25102	Structure, Support, Wood	$ 8,624,447	$ (1,100,244)	$ 7,524,202	30	0	0%	$ 377,566	55	1.82%	R4	0%	1.05	$ 160,284	$ 217,282

BC Hydro Power Authority

TABLE 1 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS
RELATED TO UTILITY PLANT AS OF MARCH 31, 2020
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Asset Class #	Description	March 31, 2020 Original Cost	March 31, 2020 Accrued Depreciation	March 31, 2020 Net Book Value	Current Life	Current Curve	Current Positive Salvage Rate	Current Depreciation Expense**	Recommended Life	Recommended Inferred Depreciation Rate**	Recommended Curve	Recommended Positive Salvage Rate	Recommended Net Salvage	Recommended Depreciation Expense for Life**	Change in Depreciation Expense*
C25201	Pole Structures < 60Kv	$ 1,452,298,893	$ (98,791,113)	$ 1,353,507,780	50	L4	0%	$ 37,070,156	50	2.00%	R2	0%	1.20	$ 37,070,160	$ (4)
C25202	Pole Structures > or = 60Kv	$ 597,590,672	$ (39,824,232)	$ 557,766,440	50	0	0%	$ 15,657,420	50	2.00%	R2.5	0%	1.30	$ 15,657,420	$ -
C25203	Tower, Lattice / Asthetic	$ 1,399,064,710	$ (81,657,058)	$ 1,317,407,653	65	0	0%	$ 28,042,072	65	1.54%	R3	0%	1.30	$ 28,042,072	$ -
C25204	Pole Structure, Composite >=60kV	$ 7,376,493	$ (214,680)	$ 7,161,813	65	0	0%	$ 142,969	65	1.54%	R3	0%	1.30	$ 142,969	$ -
C25205	Tower - Major Overhaul, Corrosion Protection	$ 35,369,840	$ (3,309,664)	$ 32,060,176	30	0	0%	$ 1,397,361	25	4.00%	SQ	0%	1.30	$ 1,754,503	$ (357,142)
C25206	Pole Structure Cross Arms > = 60Kv	$ 75,488,834	$ (11,350,121)	$ 64,138,713	30	0	0%	$ 3,700,194	30	3.33%	R2.5	0%	1.30	$ 3,700,194	$ -
C25301	Foundations	$ 287,318,065	$ (23,227,072)	$ 264,090,993	40	0	0%	$ 10,558,110	40	2.50%	R4	0%	1.05	$ 10,558,110	$ -
C25401	Ducts & Trenches	$ 70,249,408	$ (4,230,569)	$ 66,018,839	50	0	0%	$ 1,641,815	50	2.00%	R4	0%	1.20	$ 1,641,815	$ -
C25501	Ductbanks < 60Kv	$ 1,120,142,319	$ (75,396,337)	$ 1,044,745,981	50	R3	0%	$ 31,408,678	50	2.00%	R3	0%	1.30	$ 31,408,681	$ (3)
C25502	Ductbanks > or = 60Kv	$ 68,505,490	$ (5,129,078)	$ 63,376,412	50	R3	0%	$ 1,728,636	50	2.00%	R4	0%	1.30	$ 1,728,636	$ -
C25601	Barriers & Enclosures	$ 15,554,235	$ (1,068,850)	$ 14,485,386	50	0	0%	$ 396,882	50	2.00%	R3	0%	1.05	$ 396,882	$ -
C25701	Capacitor, <60 Kv	$ 3,354,739	$ (548,525)	$ 2,806,214	30	0	0%	$ 200,121	25	4.00%	R3	0%	1.10	$ 205,256	$ (5,135)
C30204	Superheater, Low Temp	$ 141,701	$ (38,017)	$ 103,684	30	0	0%	$ 20,737	30	3.33%	R3	0%	1.10	$ 20,737	$ -
C30401	Valves, Safety	$ 2,381,521	$ (459,264)	$ 1,922,257	30	0	0%	$ 153,102	30	3.33%	R3	0%	1.10	$ 153,102	$ -
C30501	Piping, High Pressure	$ 15,631,821	$ (531,828)	$ 15,099,992	40	0	0%	$ 396,222	40	2.50%	R3	0%	1.10	$ 396,222	$ -
C30606	Instrumentation, Boiler	$ 101,391	$ (8,925)	$ 92,467	30	0	0%	$ 3,386	30	3.33%	R3	0%	1.10	$ 3,386	$ -
C30607	Asbestos Abatement	$ 35,785	$ (4,617)	$ 31,167	30		0%	$ -	30	3.33%	SQ	0%	1.00	$ -	$ -
C30609	Seals, Crown	$ 42,072	$ (4,646)	$ 37,426	30	0	0%	$ 1,549	30	3.33%	R3	0%	1.10	$ 1,549	$ -
C30610	Control System, Fuel	$ 2,968,702	$ (898,095)	$ 2,070,607	15	0	0%	$ 299,365	15	6.67%	R3	0%	1.10	$ 299,365	$ -
C30613	Boiler, Package	$ 17,262,680	$ (1,938,979)	$ 15,323,701	30	0	0%	$ 699,180	30	3.33%	R3	0%	1.10	$ 699,180	$ -
C30701	Equipment, Water Treatment	$ 6,483,988	$ (968,191)	$ 5,515,797	40	0	0%	$ 364,028	35	2.86%	R4	0%	1.10	$ 172,905	$ 191,123
C30901	Monitoring Equipment, Cem	$ 7,052,411	$ (1,289,921)	$ 5,762,490	10	0	0%	$ 691,760	10	10.00%	R3	0%	1.10	$ 691,760	$ -
C31003	Gates, Inlet / Outlet	$ 8,328,327	$ (881,754)	$ 7,446,573	30	0	0%	$ 295,877	30	3.33%	R3	0%	1.10	$ 295,877	$ -
C31004	Screens, Intake	$ 338,337	$ (28,195)	$ 310,142	20	0	0%	$ 16,917	20	5.00%	R3	0%	1.10	$ 16,917	$ -
C31005	Conduit, Intake / Discharge	$ 2,764,855	$ (177,424)	$ 2,587,432	50	0	0%	$ 59,141	50	2.00%	R3	0%	1.10	$ 59,141	$ -
C31006	Valves	$ 15,079,710	$ (1,886,207)	$ 13,193,503	30	0	0%	$ 681,080	30	3.33%	R3	0%	1.10	$ 681,080	$ -
C31007	Turbine / Penstock Inlet Valves	$ 11,823,495	$ (961,522)	$ 10,861,973	50	R3	0%	$ 303,841	50	2.00%	R3	0%	1.10	$ 303,841	$ -
C33002	Pump And Motor	$ 1,607,771	$ (115,580)	$ 1,492,191	30	0	0%	$ 56,761	30	3.33%	R3	0%	1.10	$ 56,761	$ -
C33004	Condenser, Boiler	$ 5,898,240	$ (962,311)	$ 4,935,929	30	0	0%	$ 320,770	30	3.33%	R3	0%	1.10	$ 320,770	$ -
C33005	Condenser Air Removal System	$ 325	$ (325)	$ -	15	0	0%	$ -	15	6.67%	R3	0%	1.10	$ -	$ -
C34002	Casing, Cylinder	$ 4,642,065	$ (577,752)	$ 4,064,312	30	0	0%	$ 192,584	30	3.33%	R3	0%	1.10	$ 192,584	$ -
C34004	Turbine, Composite Pool	$ 4,269,199	$ (692,453)	$ 3,576,746	30	0	0%	$ 230,818	30	3.33%	R3	0%	1.10	$ 230,818	$ -
C34005	Coils, Stator	$ 2,444,964	$ (294,377)	$ 2,150,587	30	0	0%	$ 98,126	30	3.33%	R3	0%	1.10	$ 98,126	$ -
C34006	Rotor, Generator	$ 4,750,157	$ (571,925)	$ 4,178,232	30	0	0%	$ 190,642	30	3.33%	R3	0%	1.10	$ 190,642	$ -
C34007	Generator, Composite Pool	$ 1,580,110	$ (183,346)	$ 1,396,764	30	0	0%	$ 63,781	30	3.33%	R3	0%	1.10	$ 63,781	$ -
C34008	Supervisory System, Turbine	$ 5,814	$ (5,814)	$ -	20	0	0%	$ -	23	4.35%	R3	0%	1.10	$ -	$ -
C34013	Generator Oil Coolers	$ 1,751,081	$ (117,903)	$ 1,633,178	15	0	0%	$ 114,485	25	4.00%	R3	0%	1.10	$ 66,468	$ 48,017
C41001	Runner / Water Wheel	$ 138,486,335	$ (9,419,555)	$ 129,066,780	50	R2	0%	$ 3,230,484	55	1.82%	R4	0%	1.10	$ 2,850,385	$ 380,099
C41002	Governor System, Turbine	$ 63,852,141	$ (4,460,349)	$ 59,391,792	50	R4	0%	$ 1,803,867	55	1.82%	R4	0%	1.10	$ 1,476,374	$ 327,493
C41003	Casing, Embedded / Spiral Case	$ 106,696,725	$ (5,201,309)	$ 101,495,415	50	R4	0%	$ 2,276,996	50	2.00%	R3	0%	1.10	$ 2,276,996	$ -
C41004	Shaft, Turbine	$ 26,617,231	$ (1,695,231)	$ 24,922,000	50	R4	0%	$ 583,354	50	2.00%	R3	0%	1.10	$ 583,354	$ -
C41005	Gates, Wicket	$ 46,677,173	$ (2,718,902)	$ 43,958,271	50	0	0%	$ 1,053,552	50	2.00%	R2.5	0%	1.10	$ 1,053,552	$ -
C41006	Cover, Head	$ 33,124,090	$ (2,181,474)	$ 30,942,616	50	R4	0%	$ 730,017	50	2.00%	R3	0%	1.10	$ 730,017	$ -
C41007	Turbine, Hydro, Comp. Pool	$ 415,468,606	$ (42,731,580)	$ 372,737,026	50	R4	0%	$ 14,546,839	55	1.82%	R3	0%	1.10	$ 11,552,429	$ 2,994,410
C41008	Bearings For Wicket Gate	$ 4,104,882	$ (724,107)	$ 3,380,775	25	0	0%	$ 304,398	25	4.00%	R3	0%	1.10	$ 304,398	$ -
C41501	Draft Tube Water Depression System	$ 27,224,642	$ (4,208,541)	$ 23,016,101	25	R3	0%	$ 1,384,718	25	4.00%	R3	0%	1.10	$ 1,384,718	$ -
C41601	Unwatering System	$ 12,149,845	$ (2,006,530)	$ 10,143,315	25	R3	0%	$ 713,877	25	4.00%	R3	0%	1.10	$ 713,877	$ -
C41701	Turbine Air Injection Blower	$ 483,152	$ (117,896)	$ 365,256	25	0	0%	$ 40,143	25	4.00%	R3	0%	1.10	$ 40,143	$ -
C42001	Coils, Stator	$ 207,996,660	$ (22,395,059)	$ 185,601,601	30	R2.5	0%	$ 8,763,295	35	2.86%	R3.5	0%	1.10	$ 6,868,655	$ 1,894,640
C42002	Rotor, Generator	$ 218,525,091	$ (13,711,991)	$ 204,813,100	50	R4	0%	$ 5,335,737	50	2.00%	R3	0%	1.10	$ 5,335,737	$ -
C42003	Generator, Composite Pool	$ 377,529,466	$ (30,772,391)	$ 346,757,075	50	R3	0%	$ 12,055,623	50	2.00%	R3	0%	1.10	$ 12,055,623	$ -
C42004	Major Maintenance - Rewedging	$ 5,937,652	$ (1,207,623)	$ 4,730,030	25	0	0%	$ 378,141	25	4.00%	SQ	0%	1.10	$ 378,141	$ -
C42101	Exciter, Rotary	$ 4,632,280	$ (1,076,921)	$ 3,555,359	40	R1.5	0%	$ 353,591	45	2.22%	R3	0%	1.10	$ 186,590	$ 167,002
C42102	Exciter, Static	$ 51,474,150	$ (3,580,309)	$ 47,893,841	40	R4	0%	$ 1,565,992	40	2.50%	R4	0%	1.10	$ 1,565,992	$ -
C42104	Exciter, Composite Pool	$ 14,374,485	$ (2,177,642)	$ 12,196,844	40	R4	0%	$ 717,091	40	2.50%	R4	0%	1.10	$ 717,091	$ -
C42501	Piping, Water Cooling System	$ 35,438,409	$ (2,645,317)	$ 32,793,092	40	0	0%	$ 1,027,749	40	2.50%	R2	0%	1.10	$ 1,027,749	$ -
C42502	Monitoring System, Cooling	$ 121,069	$ (24,044)	$ 97,025	20	0	0%	$ 8,238	20	5.00%	R2.5	0%	1.10	$ 8,238	$ -
C46501	Cooling System, Water	$ 1,084,930	$ (645,802)	$ 439,127	15	0	0%	$ 48,792	20	5.00%	R3	0%	1.10	$ 30,026	$ 18,766
C46502	Engine, Internal Combustion	$ 20,761,882	$ (3,241,614)	$ 17,520,267	25	R2.5	0%	$ 1,072,743	25	4.00%	R3	0%	1.10	$ 1,072,743	$ -
C46701	Heat Exchanger	$ 4,615,371	$ (497,345)	$ 4,118,026	30	R3	0%	$ 204,201	30	3.33%	R3	0%	1.10	$ 204,201	$ -
C47001	Intake, Air	$ 504,775	$ (138,717)	$ 366,058	20		0%	$ -	20	5.00%	R3	0%	1.00	$ -	$ -
C47201	Turbine, Gas	$ 5,192,396	$ (2,800,277)	$ 2,392,120	25	R3	0%	$ 364,558	30	3.33%	R3	0%	1.10	$ 203,550	$ 161,007

BC Hydro Power Authority

TABLE 1 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS
RELATED TO UTILITY PLANT AS OF MARCH 31, 2020
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Asset Class #	Description	March 31, 2020 Original Cost	March 31, 2020 Accrued Depreciation	March 31, 2020 Net Book Value	Current Life	Current Curve	Current Positive Salvage Rate	Current Depreciation Expense**	Recommended Life	Recommended Inferred Depreciation Rate**	Recommended Curve	Recommended Positive Salvage Rate	Recommended Net Salvage	Recommended Depreciation Expense for Life**	Change in Depreciation Expense*
C47202	Major Maintenance - Gas Turbines	$ 4,858,364	$ (4,450,312)	$ 408,052	7	0	0%	$ 114,214	10	10.00%	SQ	0%	1.10	$ 52,725	$ 61,489
C47401	Fuel System	$ 3,355,087	$ (358,619)	$ 2,996,468	40	0	0%	$ 121,742	30	3.33%	R3	0%	1.10	$ 215,757	$ (94,016)
C48001	Coils, Stator	$ 140,633	$ (17,681)	$ 122,952	40	0	0%	$ 5,893	30	3.33%	R3	0%	1.10	$ 14,438	$ (8,545)
C48002	Rotor, Generator	$ 152,254	$ (14,610)	$ 137,644	40	0	0%	$ 4,861	30	3.33%	R3	0%	1.10	$ 7,639	$ (2,778)
C48003	Generator, Composite Pool	$ 5,283,222	$ (539,643)	$ 4,743,580	30	R2	0%	$ 250,789	30	3.33%	R3	0%	1.05	$ 250,789	$ -
C48004	Generator, Diesel	$ 66,966,846	$ (7,544,266)	$ 59,422,579	30	0	0%	$ 2,990,516	30	3.33%	R3	0%	1.05	$ 2,990,516	$ -
C49001	Pump	$ 12,838,997	$ (2,132,895)	$ 10,706,102	20	R0.5	0%	$ 720,820	20	5.00%	R3	0%	1.30	$ 720,820	$ -
C49002	Motor	$ 1,185,374	$ (145,818)	$ 1,039,557	30	0	0%	$ 49,069	30	3.33%	R3	0%	1.30	$ 49,069	$ -
C49101	Fan & Motor	$ 444,141	$ (43,046)	$ 401,095	30	0	0%	$ 14,349	25	4.00%	R3	0%	1.10	$ 17,798	$ (3,449)
C49201	Vacuum System	$ 18,310	$ (8,038)	$ 10,272	25	0	0%	$ 2,679	25	4.00%	R3	0%	1.10	$ 2,679	$ -
C51001	Condensor, Synchronous, Rotary	$ 16,155,981	$ (1,149,386)	$ 15,006,595	50	0	0%	$ 383,170	50	2.00%	R3	0%	1.30	$ 383,170	$ -
C51002	Condensor, Synchronous, Static	$ 14,658,664	$ (2,777,685)	$ 11,880,979	40	S4	0%	$ 934,178	45	2.22%	R3	0%	1.30	$ 610,257	$ 323,921
C52002	Major Overhauls for Station Equipment	$ 1,104,113	$ (84,901)	$ 1,019,212	45		0%	$ -	45	2.22%	SQ	0%	1.00	$ -	$ -
C52101	Transformer, Generator, Stepup	$ 161,120,944	$ (12,087,289)	$ 149,033,655	40	R4	0%	$ 5,053,071	40	2.50%	R4	0%	1.20	$ 5,053,071	$ -
C52102	Transformer, Auto, Bulk System	$ 60,038,782	$ (4,535,151)	$ 55,503,631	45	R4	0%	$ 2,272,774	45	2.22%	R4	0%	1.30	$ 2,272,774	$ -
C52103	Transformer, Power > 100Mva	$ 157,341,434	$ (14,791,197)	$ 142,550,237	40	R3	0%	$ 5,341,343	40	2.50%	R4	0%	1.20	$ 5,341,343	$ -
C52104	Transformer, Power < 100Mva	$ 180,473,646	$ (14,527,831)	$ 165,945,816	45	R3	0%	$ 5,112,521	45	2.22%	R3	0%	1.20	$ 5,112,521	$ -
C52105	Transformer, Station Service	$ 53,378,014	$ (3,745,309)	$ 49,632,705	40	R3	0%	$ 1,578,228	40	2.50%	R1.5	0%	1.20	$ 1,578,228	$ -
C52106	Transformer, Power, Comp Pool	$ 61,472,512	$ (13,978,547)	$ 47,493,965	45	R3	0%	$ 3,589,292	40	2.50%	R1.5	0%	1.20	$ 2,800,093	$ 789,198
C52201	Distribution - Transformer, Distribution	$ 1,088,549,737	$ (122,481,479)	$ 966,068,258	35	R2	0%	$ 45,054,245	35	2.86%	R2	0%	1.05	$ 45,054,254	$ (9)
C52202	Distribution - Distribution, Cutouts	$ 58,991,451	$ (7,886,398)	$ 51,105,053	25	0	0%	$ 2,576,426	35	2.86%	R0.5	0%	1.20	$ 1,889,348	$ 687,078
C52301	Reactor, Oil	$ 38,427,549	$ (7,335,243)	$ 31,092,305	25	R1.5	0%	$ 2,266,043	25	4.00%	R3	0%	1.30	$ 2,266,043	$ -
C52302	Reactor, Dry Type	$ 55,434,207	$ (5,071,422)	$ 50,390,031	40	R4	0%	$ 1,783,922	40	2.50%	R4	0%	1.20	$ 1,783,922	$ -
C52303	Reactor, Composite Pool	$ 7,506,892	$ (2,978,153)	$ 4,528,739	40	R4	0%	$ 585,653	40	2.50%	R4	0%	1.30	$ 585,653	$ -
C52401	Oil, 69 Kv & Above	$ 27,319,137	$ (2,451,293)	$ 24,867,844	40	R4	0%	$ 816,917	40	2.50%	R4	0%	1.30	$ 816,917	$ -
C52402	Gas, Sf6, 69 Kv & Above	$ 44,395,584	$ (3,652,331)	$ 40,743,253	40	R1.5	0%	$ 1,391,944	40	2.50%	R4	0%	1.20	$ 1,391,944	$ -
C52403	Oil, < 69 Kv	$ 30,039	$ (5,206)	$ 24,833	35	0	0%	$ 1,492	38	2.63%	S0.5	0%	1.30	$ 1,227	$ 265
C52404	Transformer, Current, Encaps.	$ 4,719,760	$ (870,811)	$ 3,848,949	45	R3	0%	$ 297,130	45	2.22%	R3	0%	1.20	$ 297,130	$ -
C52405	Transformer, Current, Comp. Pool	$ 28,112,697	$ (2,539,383)	$ 25,573,315	50	R4	0%	$ 848,507	50	2.00%	R4	0%	1.20	$ 848,507	$ -
C52406	Comb Ct & Vt Transformer	$ 2,684,562	$ (205,997)	$ 2,478,565	40	0	0%	$ 76,533	45	2.22%	R3	0%	1.30	$ 65,729	$ 10,805
C52501	Transformer, Voltage, Capacitor	$ 67,094,883	$ (6,002,335)	$ 61,092,548	35	0	0%	$ 2,305,315	35	2.86%	R4	0%	1.30	$ 2,305,315	$ -
C52502	Transformer, Voltage, Oil-Fill	$ 6,814,164	$ (595,945)	$ 6,218,219	40	0	0%	$ 197,880	40	2.50%	R3	0%	1.20	$ 197,880	$ -
C52503	Transformer, Voltage, Gas-Fill	$ 7,551,806	$ (425,200)	$ 7,126,605	50	0	0%	$ 175,866	50	2.00%	R3	0%	1.30	$ 175,866	$ -
C52504	Transformer, Voltage, Encaps.	$ 8,007,875	$ (615,576)	$ 7,392,299	45	0	0%	$ 233,112	45	2.22%	R3	0%	1.20	$ 233,112	$ -
C52505	Transformer, Volt, Comp. Pool	$ 6,276,362	$ (909,675)	$ 5,366,687	40	0	0%	$ 223,887	40	2.50%	R4	0%	1.30	$ 223,887	$ -
C52601	Mobile Substations	$ 9,108,997	$ (1,400,312)	$ 7,708,685	25	R3	0%	$ 470,568	25	4.00%	R3	0%	1.30	$ 470,568	$ -
C53101	Capacitor, Shunt	$ 24,860,756	$ (5,174,891)	$ 19,685,865	30	S4	0%	$ 1,200,252	30	3.33%	R3	0%	1.30	$ 1,200,252	$ -
C53201	Capacitor, Series	$ 44,954,653	$ (4,949,552)	$ 40,005,101	35	R4	0%	$ 1,660,213	35	2.86%	R3	0%	1.30	$ 1,660,213	$ -
C53202	Metal Oxide Varister (Mov)	$ 13,643,859	$ (1,441,701)	$ 12,202,158	35	R1	0%	$ 481,241	35	2.86%	R3	0%	1.05	$ 481,241	$ -
C53301	Capacitor, Coupling	$ 1,210,895	$ (160,673)	$ 1,050,222	35	R4	0%	$ 44,259	35	2.86%	R3	0%	1.30	$ 44,259	$ -
C54101	Breaker, Air / Magnetic	$ 24,555,153	$ (3,262,840)	$ 21,292,313	20	0	0%	$ 1,141,436	20	5.00%	R3	0%	1.20	$ 1,141,436	$ -
C54102	Breaker, Gas (Sf6) 12 / 25 Kv	$ 178,778,377	$ (19,617,317)	$ 159,161,060	30	R3	0%	$ 7,563,265	35	2.86%	R3	0%	1.20	$ 6,067,416	$ 1,495,849
C54103	Breaker, Bulk / Min Oil / Air Blast	$ 21,988,542	$ (1,789,295)	$ 20,199,247	45	R4	0%	$ 611,114	45	2.22%	R3	0%	1.30	$ 611,114	$ -
C54104	Breaker, Gas (Sf6), 69 To 500 Kv	$ 440,821,156	$ (33,034,765)	$ 407,786,390	45	R2.5	0%	$ 12,030,908	45	2.22%	R3	0%	1.20	$ 12,030,908	$ -
C54105	Breakers, Composite Pool	$ 17,236,094	$ (2,653,116)	$ 14,582,978	35	L4	0%	$ 784,672	35	2.86%	R4	0%	1.30	$ 784,672	$ -
C54201	Use Individual Disconnect Caus	$ 20,961,393	$ (7,208,581)	$ 13,752,812	40	0	0%	$ 1,501,967	35	2.86%	R3	0%	1.20	$ 1,373,546	$ 128,422
C54202	Disconnect, 1 Phase, Hookstick	$ 1,813,741	$ (229,269)	$ 1,584,472	30	0	0%	$ 86,323	35	2.86%	R3	0%	1.30	$ 68,475	$ 17,848
C54203	Disconnect, 3 Phase, 12 / 25Kv	$ 61,092,651	$ (5,258,724)	$ 55,833,927	35	R2.5	0%	$ 2,113,538	35	2.86%	R3	0%	1.20	$ 2,113,538	$ -
C54204	Disconnect, 3 Phase, 69 to 230Kv	$ 93,621,922	$ (8,428,115)	$ 85,193,807	35	R2.5	0%	$ 3,303,855	35	2.86%	R3	0%	1.20	$ 3,303,855	$ -
C54205	Disconnect, 3 Phase, 500Kv	$ 71,713,306	$ (6,640,393)	$ 65,072,914	35	R2.5	0%	$ 2,572,463	35	2.86%	R3	0%	1.20	$ 2,572,463	$ -
C54401	Switchgear, Metalclad	$ 71,468,675	$ (6,972,758)	$ 64,495,918	30	R3	0%	$ 3,013,507	30	3.33%	R3	0%	1.30	$ 3,013,510	$ (3)
C54501	Circuit Recloser	$ 96,879,799	$ (5,757,971)	$ 91,121,828	40	0	0%	$ 2,745,532	40	2.50%	R3	0%	1.30	$ 2,745,532	$ -
C54601	Circuit Switcher	$ 9,093,577	$ (1,130,500)	$ 7,963,077	30	R4	0%	$ 385,131	30	3.33%	R3	0%	1.30	$ 385,131	$ -
C55101	Conductor, Overhead > or = 60 Kv	$ 749,347,904	$ (51,087,322)	$ 698,260,582	60	0	0%	$ 17,544,973	55	1.82%	R3	0%	1.30	$ 21,089,638	$ (3,544,665)
C55102	Conductor, Overhead < 60 Kv	$ 782,029,570	$ (62,269,924)	$ 719,759,645	45	R1	0%	$ 22,609,043	50	2.00%	R3	0%	1.20	$ 19,383,563	$ 3,225,480
C55103	Line Disconnect Switches	$ 20,810,702	$ (2,905,825)	$ 17,904,877	25	0	0%	$ 1,041,912	25	4.00%	R3	0%	1.30	$ 1,041,912	$ -
C55104	Overhead Collision Avoidance System	$ 2,037,217	$ (1,549,440)	$ 487,777	5	0	0%	$ -	25	4.00%	R3	0%	1.30	$ 3,455	$ (3,455)
C55201	Overhead Conductor Services < 60 Kv	$ 300,338,158	$ (25,812,775)	$ 274,525,383	45	0	0%	$ 9,674,880	45	2.22%	R3	0%	1.20	$ 9,674,901	$ (21)
C55202	Underground Conductor Services < 60 Kv	$ 113,314,645	$ (7,975,699)	$ 105,338,945	45	0	0%	$ 3,055,934	45	2.22%	R3	0%	1.20	$ 3,055,945	$ (11)
C55301	Cable, Underground < 60 Kv	$ 975,834,256	$ (94,287,806)	$ 881,546,451	40	R3	0%	$ 34,536,718	40	2.50%	R2	0%	1.20	$ 34,536,718	$ -
C55302	Cable, Underground > or = 60Kv	$ 107,551,910	$ (12,797,241)	$ 94,754,670	40	R4	0%	$ 3,767,569	45	2.22%	R3	0%	1.30	$ 2,911,953	$ 855,616
C55303	Cable, Submarine > or = 60 Kv	$ 270,715,556	$ (46,189,173)	$ 224,526,383	45	R4	0%	$ 13,306,561	45	2.22%	R3	0%	1.00	$ 13,306,561	$ -
C55304	Cable, Submarine < 60 Kv	$ 63,617,598	$ (4,883,295)	$ 58,734,303	35	0	0%	$ 2,330,819	30	3.33%	R3	0%	1.20	$ 2,815,437	$ (484,618)

BC Hydro Power Authority

TABLE 1 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS
RELATED TO UTILITY PLANT AS OF MARCH 31, 2020
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Asset Class #	Description	March 31, 2020 Original Cost	March 31, 2020 Accrued Depreciation	March 31, 2020 Net Book Value	Current Life	Current Curve	Current Positive Salvage Rate	Current Depreciation Expense**	Recommended Life	Recommended Inferred Depreciation Rate**	Recommended Curve	Recommended Positive Salvage Rate	Recommended Net Salvage	Recommended Depreciation Expense for Life**	Change in Depreciation Expense*
C55305	Cable, Submarine , Pumping Plant	$ 24,910,795	$ (4,559,857)	$ 20,350,938	25	0	0%	$ 1,453,174	25	4.00%	R3	0%	1.30	$ 1,453,174	$ -
C55307	Cable, Submarine > or = 60kV - Major Inspection	$ 1,465,543	$ (1,067,107)	$ 398,435	5	0	0%	$ 56,919	5	20.00%	SQ	0%	1.30	$ 56,919	$ -
C55308	Cable Monitor System, Underground > = 60Kv	$ 1,532,980	$ (624,189)	$ 908,791	10	0	0%	$ 289,613	10	10.00%	R3	0%	1.30	$ 289,613	$ -
C55401	Buswork & Station Conductor	$ 421,934,169	$ (25,566,523)	$ 396,367,646	60	0	0%	$ 9,706,671	55	1.82%	R4	0%	1.20	$ 11,138,852	$ (1,432,181)
C55501	Grounding Systems	$ 72,401,598	$ (6,030,242)	$ 66,371,356	40	0	0%	$ 2,379,081	40	2.50%	R3	0%	1.20	$ 2,379,081	$ -
C56001	Insulators	$ 102,494,943	$ (6,348,976)	$ 96,145,967	55	0	0%	$ 2,133,913	55	1.82%	R3	0%	1.30	$ 2,133,913	$ -
C57001	Arrestor, Surge	$ 50,667,391	$ (5,995,460)	$ 44,671,930	30	0	0%	$ 2,146,578	30	3.33%	R4	0%	1.20	$ 2,146,578	$ -
C58001	Converter	$ 140,927	$ (15,762)	$ 125,165	30	0	0%	$ 7,903	30	3.33%	R3	0%	1.30	$ 7,903	$ -
C58002	Inverter	$ 1,129,037	$ (206,992)	$ 922,045	30	0	0%	$ 74,666	30	3.33%	R3	0%	1.30	$ 74,666	$ -
C58101	Var Compensator, Static	$ 12,484,909	$ (1,377,777)	$ 11,107,132	40	R3	0%	$ 526,710	35	2.86%	R4	0%	1.05	$ 697,957	$ (171,247)
C58201	Resistor, Anode Damping	$ 198,236	$ (76,889)	$ 121,347	25	0	0%	$ 5,832	25	4.00%	R3	0%	1.05	$ 5,832	$ -
C58901	Power Supply, Solar Panel	$ 1,869,908	$ (1,014,971)	$ 854,937	10	0	0%	$ 189,865	10	10.00%	R3	0%	1.05	$ 189,865	$ -
C59001	Power Supply, Uninterruptible	$ 4,440,828	$ (1,346,033)	$ 3,094,795	15	R3	0%	$ 359,469	5	20.00%	SQ	0%	1.05	$ 305,901	$ 53,568
C59101	Regulator, Feeder Circuit	$ 19,569,721	$ (2,441,304)	$ 17,128,417	30	R3	0%	$ 793,242	35	2.86%	R3	0%	1.30	$ 619,271	$ 173,971
C59201	Charger System, Battery	$ 23,494,925	$ (4,648,676)	$ 18,846,249	20	0	0%	$ 1,554,997	17	5.88%	R4	0%	1.05	$ 1,950,608	$ (395,611)
C59202	Electric Vehicle Charging Stations								7	14.29%	R3	0%	1.20		
C59301	Storage Batteries, Bank	$ 33,649,647	$ (5,286,524)	$ 28,363,123	20	0	0%	$ 2,613,094	15	6.67%	R4	0%	1.05	$ 4,408,074	$ (1,794,980)
C59401	Distribution - Meters, Billing, Distribution	$ 54,131,183	$ (10,172,734)	$ 43,958,449	25	R2	0%	$ 3,388,223	20	5.00%	R1	0%	1.20	$ 4,653,347	$ (1,265,124)
C59402	Distribution - Meters, Transmission	$ 7,721,395	$ (658,961)	$ 7,062,434	30	0	0%	$ 329,880	30	3.33%	R3	0%	1.20	$ 329,880	$ -
C59403	Distribution - Automated Meters, Distribution	$ 396,996,142	$ (71,325,008)	$ 325,671,134	20	0	0%	$ 26,065,079	20	5.00%	R4	0%	1.20	$ 26,065,079	$ -
C59501	Street Lights,Distribution, Owned	$ 29,826,882	$ (3,543,752)	$ 26,283,130	40	R3	0%	$ 1,234,503	40	2.50%	R3	0%	1.05	$ 1,234,503	$ -
C59503	Streetlight LED	$ -	$ -	$ -	20	0	0%	$ 103,125	20	5.00%	R3	0%	1.20	$ 51,442	$ 51,683
C59601	Metering, Dcp, Trolleys	$ 1,553,712	$ (350,843)	$ 1,202,869	35	0	0%	$ 121,192	25	4.00%	R3	0%	1.20	$ 135,648	$ (14,455)
C61001	Fencing	$ 41,775,105	$ (6,008,856)	$ 35,766,249	25	0	0%	$ 2,363,896	25	4.00%	R3	0%	1.05	$ 2,363,896	$ -
C61101	Alarm / Security System	$ 65,952,788	$ (11,619,853)	$ 54,332,934	20	0	0%	$ 4,447,429	15	6.67%	R3.5	0%	1.05	$ 7,567,216	$ (3,119,787)
C61201	Booms, Floating	$ 6,535,500	$ (1,243,578)	$ 5,291,923	15	0	0%	$ 528,761	20	5.00%	R4	0%	1.10	$ 356,395	$ 172,367
C61202	Booms, Floating Cedar	$ 7,521,385	$ (570,044)	$ 6,951,341	25	0	0%	$ 368,142	20	5.00%	R2	0%	1.10	$ 452,693	$ (84,551)
C62001	Fire Protection System	$ 106,182,848	$ (13,310,344)	$ 92,872,504	25	0	0%	$ 5,578,982	25	4.00%	R3	0%	1.05	$ 5,578,982	$ -
C62501	Firefighting Equipment	$ 3,724,129	$ (278,597)	$ 3,445,531	25	0	0%	$ 188,336	25	4.00%	R4	0%	1.05	$ 188,336	$ -
C63001	Exercise Equipment	$ 164,611	$ (110,466)	$ 54,145	5	0	0%	$ 10,569	5	20.00%	SQ	0%	1.00	$ 10,569	$ -
C65001	Protection and Control Equipment and Relay	$ 475,691,828	$ (84,959,817)	$ 390,732,011	20	0	0%	$ 32,205,049	20	5.00%	R4	0%	1.05	$ 32,205,049	$ -
C65101	Fault Locating & Reporting	$ 5,909,228	$ (936,712)	$ 4,972,515	20	0	0%	$ 414,642	20	5.00%	R3	0%	1.05	$ 414,642	$ -
C67001	Liner, Pvc, Spill Containment	$ 379,695	$ (79,107)	$ 300,588	35	0	0%	$ 26,369	35	2.86%	R3	0%	1.30	$ 26,369	$ -
C67003	Containment Facility, Concrete	$ 26,714,778	$ (1,872,630)	$ 24,842,148	50	0	0%	$ 687,630	50	2.00%	R3	0%	1.05	$ 687,630	$ -
C67004	Spill Pond, Natural	$ 67,216	$ (20,135)	$ 47,081	25	0	0%	$ 6,712	25	4.00%	R3	0%	1.10	$ 6,712	$ -
C67005	Oil Spill Containment	$ 7,996,193	$ (1,094,828)	$ 6,901,365	35	R3	0%	$ 407,457	35	2.86%	R3	0%	1.05	$ 407,457	$ -
C67006	Containment System, Oil Spill	$ 14,757,248	$ (1,558,534)	$ 13,198,713	35	0	0%	$ 571,322	35	2.86%	R3	0%	1.30	$ 571,322	$ -
C68001	Carrier System, Power Line	$ 6,982,151	$ (3,122,335)	$ 3,859,817	15	0	0%	$ 536,161	15	6.67%	R3	0%	1.30	$ 536,161	$ -
C68101	Antennae & Waveguide, Microwave	$ 29,502,559	$ (5,489,651)	$ 24,012,909	20	0	0%	$ 1,663,780	20	5.00%	R4	0%	1.05	$ 1,663,780	$ -
C68201	Control Centre (Master Equip)	$ 46,542,409	$ (13,918,072)	$ 32,624,336	12	R2	0%	$ 4,900,233	12	8.33%	R3	0%	1.05	$ 4,900,233	$ -
C68202	Terminal Unit, Remote (Slave)	$ 36,504,213	$ (6,983,550)	$ 29,520,663	20	0	0%	$ 2,525,709	20	5.00%	R5	0%	1.05	$ 2,525,709	$ -
C68203	Integrated Control / Data (Icda)	$ 845,438	$ (434,326)	$ 411,112	5	0	0%	$ 25,651	5	20.00%	R4	0%	1.05	$ 25,651	$ -
C68204	Distributed Control System	$ 24,017,974	$ (2,549,491)	$ 21,468,483	20	R2	0%	$ 1,624,127	20	5.00%	R4	0%	1.05	$ 1,624,127	$ -
C68205	Global Positioning Equipment	$ 337,304	$ (117,512)	$ 219,792	10	0	0%	$ 37,862	10	10.00%	R3	0%	1.05	$ 37,862	$ -
C68301	Radio, Microwave, Analog	$ 2,124,284	$ (289,326)	$ 1,834,959	35	0	0%	$ 97,730	25	4.00%	R3	0%	1.05	$ 165,523	$ (67,793)
C68302	Radio, Microwave, Digital	$ 40,725,868	$ (4,586,609)	$ 36,139,259	35	R4	0%	$ 1,603,080	20	5.00%	R3	0%	1.05	$ 5,179,465	$ (3,576,385)
C68303	Microwave, Conversion Only	$ 5,907	$ (5,413)	$ 494	20		0%	$ -	20	5.00%	R3	0%	1.00	$ -	$ -
C68401	Multiplex Device, Analog	$ 13,986	$ (2,797)	$ 11,189	5	0	0%	$ 2,806	5	20.00%	R5	0%	1.10	$ 2,806	$ -
C68402	Multiplex Device, Digital	$ 22,741,873	$ (4,812,876)	$ 17,928,997	20	S3	0%	$ 1,592,541	15	6.67%	R3	0%	1.10	$ 1,662,148	$ (69,607)
C68501	Radio Systems, Uhf/Vhff	$ 18,660,898	$ (3,330,727)	$ 15,330,170	35	0	0%	$ 1,119,436	30	3.33%	R3	0%	1.05	$ 2,491,576	$ (1,372,140)
C68502	Mobile Dispatch System	$ 12,008	$ (12,008)	$ -	5	0	0%	$ -	5	20.00%	SQ	0%	1.05	$ -	$ -
C68503	Radio Equipment, Protection	$ 4,699,561	$ (664,235)	$ 4,035,326	25	0	0%	$ 364,031	20	5.00%	R3	0%	1.05	$ 490,622	$ (126,591)
C68601	Protection Tone System	$ 25,932,229	$ (5,575,491)	$ 20,356,738	20	0	0%	$ 1,766,053	20	5.00%	R3	0%	1.10	$ 1,766,053	$ -
C68602	Digital Teleprotection System	$ 7,346,672	$ (1,564,882)	$ 5,781,790	20	0	0%	$ 532,877	20	5.00%	R3	0%	1.30	$ 532,877	$ -
C68701	Wave Trap / Line Trap	$ 1,843,122	$ (409,163)	$ 1,433,959	20	0	0%	$ 135,571	20	5.00%	R3	0%	1.30	$ 135,571	$ -
C68801	Fibre Optic System	$ 30,250,382	$ (6,121,099)	$ 24,129,283	20	0	0%	$ 2,060,062	20	5.00%	R4	0%	1.05	$ 2,060,062	$ -
C68901	Telephone Equipment, Pbx/Pax	$ 1,483,623	$ (142,270)	$ 1,341,353	20	R2	0%	$ 78,402	5	20.00%	SQ	0%	1.00	$ 400,495	$ (322,093)
C68903	Telephone Equipment, Monitoring System	$ 2,085,655	$ (1,445,119)	$ 640,536	5	0	0%	$ 94,843	5	20.00%	R3	0%	1.00	$ 94,843	$ -
C68904	Telephone System, Cellular	$ 7,060,456	$ (3,525,583)	$ 3,534,873	5	0	0%	$ 1,329,798	3	33.33%	SQ	0%	1.00	$ 1,594,446	$ (264,647)
C70001	Cable, Entrance Protection	$ 6,337,455	$ (1,298,972)	$ 5,038,482	20	0	0%	$ 441,086	20	5.00%	R3	0%	1.30	$ 441,086	$ -
C70101	Hydrometeorological Equipment	$ 6,190,842	$ (1,084,854)	$ 5,105,988	15	0	0%	$ 491,404	15	6.67%	R3	0%	1.10	$ 491,404	$ -
C70102	Accelerometers	$ 2,166,236	$ (424,964)	$ 1,741,271	20	0	0%	$ 131,064	20	5.00%	R3	0%	1.05	$ 131,064	$ -
C70103	Seismic Monitoring Equipment	$ 3,670,101	$ (977,916)	$ 2,692,185	20	R2	0%	$ 309,863	20	5.00%	R3	0%	1.30	$ 309,863	$ -

BC Hydro Power Authority

TABLE 1 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS
RELATED TO UTILITY PLANT AS OF MARCH 31, 2020
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Asset Class #	Description	March 31, 2020 Original Cost	March 31, 2020 Accrued Depreciation	March 31, 2020 Net Book Value	Current Life	Current Curve	Current Positive Salvage Rate	Current Depreciation Expense**	Recommended Life	Recommended Inferred Depreciation Rate**	Recommended Curve	Recommended Positive Salvage Rate	Recommended Net Salvage	Recommended Depreciation Expense for Life**	Change in Depreciation Expense*
C70104	Instrumentation - Digital	$ 32,832,760	$ (4,869,159)	$ 27,963,601	25	0	0%	$ 1,808,044	20	5.00%	R3	0%	1.10	$ 2,298,113	$ (490,069)
C70105	Instrumentation - Analogue	$ 1,747,102	$ (189,795)	$ 1,557,306	40	0	0%	$ 78,971	25	4.00%	R3	0%	1.10	$ 346,907	$ (267,936)
C73001	Cooling System, Air	$ 19,598,263	$ (2,682,503)	$ 16,915,760	25	S4	0%	$ 889,384	25	4.00%	R3	0%	1.05	$ 889,384	$ -
C74001	Motor - Generator Sets	$ 21,969,822	$ (2,234,737)	$ 19,735,085	35	S4	0%	$ 748,275	35	2.86%	R3	0%	1.05	$ 748,275	$ -
C75101	Drier, Air	$ 796,764	$ (261,062)	$ 535,702	25	0	0%	$ 70,128	25	4.00%	R3	0%	1.30	$ 70,128	$ -
C75102	Piping / Valving, Steel	$ 547,149	$ (128,019)	$ 419,130	20	0	0%	$ 38,989	20	5.00%	R3	0%	1.30	$ 38,989	$ -
C75103	Piping, Stainless Steel	$ 1,935,476	$ (196,801)	$ 1,738,675	40	0	0%	$ 69,279	40	2.50%	R3	0%	1.30	$ 69,279	$ -
C75104	Compressor, Air	$ 12,014,440	$ (1,846,972)	$ 10,167,468	25	R3	0%	$ 746,929	25	4.00%	R3	0%	1.30	$ 746,929	$ -
C75201	Tanks, Steel, Air / Fuel	$ 7,027,624	$ (1,138,880)	$ 5,888,744	30	0	0%	$ 366,449	30	3.33%	R3	0%	1.05	$ 366,449	$ -
C75202	Tank, Fiberglass,Double Bottom, Fuel	$ 1,503,351	$ (220,785)	$ 1,282,566	30	0	0%	$ 75,756	30	3.33%	R3	0%	1.30	$ 75,756	$ -
C75203	Tank, Air - Stainless / Oil - Steel	$ 6,261,841	$ (821,637)	$ 5,440,204	30	R2	0%	$ 282,097	30	3.33%	R3	0%	1.05	$ 282,097	$ -
C75204	Tanks, Concrete	$ 2,089,642	$ (345,314)	$ 1,744,329	30	R2	0%	$ 121,055	30	3.33%	R3	0%	1.30	$ 121,055	$ -
C75205	Tanks, Wood	$ 182,035	$ (35,616)	$ 146,419	25	0	0%	$ 11,872	25	4.00%	R3	0%	1.10	$ 11,872	$ -
C75301	Water Supply System	$ 24,685,332	$ (2,343,683)	$ 22,341,649	40	0	0%	$ 805,246	40	2.50%	R3.5	0%	1.05	$ 805,246	$ -
C80101	Computer, Hardware, Micro (PC)	$ 11,596,587	$ (7,903,689)	$ 3,692,898	4	0	0%	$ 508,744	4	25.00%	SQ	0%	1.00	$ 508,744	$ -
C80103	Computer, Hardware, Input / Output	$ 6,644,745	$ (5,457,535)	$ 1,187,210	5	0	0%	$ 188,388	5	20.00%	SQ	0%	1.00	$ 188,388	$ -
C80105	Laptops	$ 15,590,304	$ (9,555,587)	$ 6,034,717	3	0	0%	$ 3,023,368	4	25.00%	SQ	0%	1.00	$ 2,666,891	$ 356,477
C80204	Storage Device, Disc / Tape	$ 18,902,097	$ (9,679,880)	$ 9,222,217	5	0	0%	$ 2,578,858	5	20.00%	SQ	0%	1.00	$ 2,578,858	$ -
C80302	Software, Enterprise Systems	$ 140,630,924	$ (73,607,719)	$ 67,023,205	10	0	0%	$ 19,785,294	10	10.00%	SQ	0%	1.00	$ 19,785,294	$ -
C80303	Software, Mid-Range Systems	$ 146,901,780	$ (73,330,444)	$ 73,571,336	5	0	0%	$ 20,245,922	5	20.00%	SQ	0%	1.00	$ 20,245,922	$ -
C80305	Software Upgraded Enterprise Systems	$ 23,997,433	$ (17,623,446)	$ 6,373,987	2	0	0%	$ 767,401	2	50.00%	SQ	0%	1.00	$ 767,401	$ -
C80314	PC Software	$ 40,115,659	$ (14,815,954)	$ 25,299,705	4	0	0%	$ 7,886,339	4	25.00%	SQ	0%	1.00	$ 7,886,339	$ -
C80318	Software 5 year life - Internally Developed	$ 38,608,043	$ (29,471,361)	$ 9,136,682	5	0	0%	$ 4,801,860	5	20.00%	SQ	0%	1.00	$ 4,801,860	$ -
C80319	Software 10 year life - Internally Developed	$ 57,181,708	$ (22,478,370)	$ 34,703,338	10	0	0%	$ 6,171,378	10	10.00%	SQ	0%	1.00	$ 6,171,378	$ -
C80501	Premise Cabling	$ 1,297,637	$ (496,689)	$ 800,948	7	0	0%	$ 473,959	7	14.29%	SQ	0%	1.00	$ 473,959	$ -
C80502	Routers	$ 17,968,024	$ (9,930,955)	$ 8,037,069	5	0	0%	$ 1,860,282	7	14.29%	SQ	0%	1.00	$ 1,183,179	$ 677,103
C80503	Switches	$ 9,202,989	$ (3,913,146)	$ 5,289,843	5	0	0%	$ 1,918,819	7	14.29%	SQ	0%	1.00	$ 1,262,795	$ 656,024
C80504	Servers	$ 28,444,468	$ (14,783,928)	$ 13,660,539	5	0	0%	$ 2,543,155	5	20.00%	SQ	0%	1.00	$ 2,543,155	$ -
C80508	Misc. Network Equipment	$ 14,325,963	$ (10,021,905)	$ 4,304,058	4	0	0%	$ 1,303,559	4	25.00%	R3	0%	1.00	$ 1,303,559	$ -
C81001	Automobiles	$ 1,977,874	$ (565,681)	$ 1,412,193	8	L2.5	20%	$ 162,482	10	10.00%	L3	15%	0.85	$ 124,204	$ 38,278
C81101	Trucks < 1 Ton 2 Wheel Drive	$ 1,945,142	$ (426,376)	$ 1,518,766	8	L2.5	20%	$ 178,687	10	10.00%	L3	15%	0.85	$ 138,963	$ 39,724
C81201	Trucks < 1 Ton 4 Wheel Drive	$ 39,320,229	$ (10,121,418)	$ 29,198,811	8	L2.5	20%	$ 3,759,237	10	10.00%	L3	15%	0.85	$ 3,041,070	$ 718,166
C81301	Trucks > = 1 Ton 2 Wheel Drive	$ 14,286,403	$ (3,688,192)	$ 10,598,211	13	R1.5	15%	$ 945,409	10	10.00%	L3	9%	0.91	$ 875,325	$ 70,083
C81302	Truck > = 1 Ton 2 Wheel Drive	$ 1,723,873	$ (752,213)	$ 971,661	13	R1.5	5%	$ 163,151	10	10.00%	L3	9%	0.91	$ -	$ 163,151
C81401	Trucks > = 1 Ton 4 Wheel Drive	$ 65,215,898	$ (11,036,692)	$ 54,179,207	13	0	25%	$ 4,229,463	12	8.33%	L3	5%	0.95	$ 6,927,847	$ (2,698,384)
C81501	Trucks > = 1 Ton 6 Wheel Drive	$ 24,932,335	$ (7,343,318)	$ 17,589,016	12	0	10%	$ 2,178,326	14	7.14%	L3	5%	0.95	$ 1,890,014	$ 288,312
C81601	Tractor, Highway	$ 27,949	$ -	$ 27,949	9	L2.5	10%	$ -	12	8.33%	L3	5%	0.95	$ -	$ -
C81701	Aerial Device	$ 23,372,371	$ (5,884,140)	$ 17,488,231	13	0	10%	$ 1,819,404	12	8.33%	L3	5%	0.95	$ 2,162,099	$ (342,695)
C81702	Line / Service / Van Body	$ 31,463,005	$ (4,723,329)	$ 26,739,676	15	R3	15%	$ 2,368,159	10	10.00%	L3	9%	0.91	$ 3,460,994	$ (1,092,834)
C81703	Derricks / Diggers	$ 19,638,541	$ (3,746,451)	$ 15,892,090	15	0	20%	$ 1,353,090	15	6.67%	L3	5%	0.95	$ 2,052,304	$ (699,214)
C81704	Ride-A-Rails	$ 34,046	$ (5,173)	$ 28,873	25	0	15%	$ 1,724	16	6.25%	L3	7%	0.93	$ 10,114	$ (8,390)
C82501	Forklift / Pallet Jack	$ 10,775,590	$ (1,388,589)	$ 9,387,001	20	R3	20%	$ 483,496	16	6.25%	L3	7%	0.93	$ 928,016	$ (444,520)
C82502	Snow Vehicle	$ 2,349,657	$ (164,399)	$ 2,185,258	20	R3	40%	$ 69,053	15	6.67%	L3	10%	0.90	$ 258,602	$ (189,549)
C82503	Sweeper	$ 40,101	$ (5,965)	$ 34,136	15	0	15%	$ 967	16	6.25%	L3	7%	0.93	$ 1,906	$ (939)
C82504	Loader / Backhoe	$ 2,067,293	$ (177,725)	$ 1,889,568	17	R1.5	45%	$ 78,395	16	6.25%	L3	7%	0.93	$ 166,534	$ (88,139)
C82505	Trailer, Reel / Pole / Utility	$ 16,036,830	$ (2,223,726)	$ 13,813,104	20	R1.5	10%	$ 875,708	18	5.56%	L3	10%	0.90	$ 1,019,375	$ (143,667)
C82506	Welder, Mobile, Self-Powered	$ 103,854	$ (24,263)	$ 79,590	15	0	15%	$ 8,464	15	6.67%	L3	10%	0.90	$ 10,051	$ (1,588)
C82507	Compressor, Mobile, Self-Powered	$ 32,147	$ (5,186)	$ 26,960	15	0	10%	$ 1,729	15	6.67%	L3	10%	0.90	$ 1,729	$ -
C82508	Chipper	$ 44,270	$ (3,812)	$ 40,459	15	0	15%	$ 2,287	16	6.25%	L3	7%	0.93	$ 2,358	$ (71)
C82509	Tractor	$ 279,877	$ (42,668)	$ 237,209	10	0	30%	$ 10,137	10	10.00%	L3	10%	0.90	$ 14,954	$ (4,817)
C82512	Regen Plan, Xformer Oil	$ 3,172,031	$ (747,566)	$ 2,424,465	15	0	0%	$ 249,189	15	6.67%	R3	0%	1.05	$ 249,189	$ -
C82513	Manlift	$ 517,172	$ (150,029)	$ 367,142	15	0	0%	$ 51,855	16	6.25%	R3	7%	0.93	$ 42,522	$ 9,333
C82514	All Terrain Vehicle	$ 1,951,939	$ (571,263)	$ 1,380,676	8	0	15%	$ 224,994	8	12.50%	R3	10%	0.90	$ 252,211	$ (27,217)
C82550	Tools / Work Equipment, Misc	$ 81,506,605	$ (19,314,710)	$ 62,191,896	15	0	0%	$ 7,211,170	15	6.67%	SQ	0%	1.05	$ 7,211,170	$ -
C82551	Tools / Work Equipment, Misc	$ 2,289,727	$ (1,846,352)	$ 443,376	15		0%	$ -	15	6.67%	SQ	0%	1.00	$ -	$ -
C82601	Test / Calibration Equipment	$ 12,920,793	$ (2,501,795)	$ 10,418,998	15	SQ	0%	$ 1,162,032	15	6.67%	R3	0%	1.05	$ 1,162,032	$ -
C82603	Manufacturing / Test Equipment	$ 319,257	$ (99,339)	$ 219,918	15	0	0%	$ 23,688	15	6.67%	R3	0%	1.05	$ 23,688	$ -
C83001	Boat	$ 846,353	$ (249,830)	$ 596,523	15	0	0%	$ 88,610	15	6.67%	R3	0%	1.00	$ 98,367	$ (9,757)
C85001	Office Furniture	$ 66,538,809	$ (15,564,037)	$ 50,974,772	15	0	0%	$ 5,756,732	15	6.67%	SQ	0%	1.00	$ 5,756,732	$ -
C85002	Office Equipment	$ 79,010	$ (71,349)	$ 7,662	15		0%	$ -	15	6.67%	SQ	0%	1.00	$ -	$ -
C85003	Signs / Plaques	$ 406,737	$ (69,726)	$ 337,012	30		0%	$ -	30	3.33%	SQ	0%	1.00	$ -	$ -
C85004	Carpet	$ 197,194	$ (118,316)	$ 78,878	15		0%	$ -	15	6.67%	SQ	0%	1.00	$ -	$ -
C88002	Lab Equipment, Misc.	$ 1,040,518	$ (435,921)	$ 604,597	15	0	0%	$ 57,745	15	6.67%	R3	0%	1.00	$ 57,745	$ -

BC Hydro Power Authority

TABLE 1 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS
RELATED TO UTILITY PLANT AS OF MARCH 31, 2020
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Asset Class #	Description	March 31, 2020 Original Cost	March 31, 2020 Accrued Depreciation	March 31, 2020 Net Book Value	Current Life	Current Curve	Current Positive Salvage Rate	Current Depreciation Expense**	Recommended Life	Recommended Inferred Depreciation Rate**	Recommended Curve	Recommended Positive Salvage Rate	Recommended Net Salvage	Recommended Depreciation Expense for Life**	Change in Depreciation Expense*
C89501	Animal Preventative Equipment	$ 13,339,108	$ (2,458,063)	$ 10,881,045	20	0	0%	$ 939,523	20	5.00%	R3	0%	1.30	$ 939,523	$ -
C90004	Water User Plans	$ 446,090	$ (440,564)	$ 5,526	10	0	100%	$ -	10	10.00%	SQ	0%	1.00	$ -	$ -
		$ 25,353,739,619	**$ (2,445,780,124)**	**$ 22,907,986,742**				**$ 865,879,014**						**$ 860,668,149**	**$ 5,210,865**
TOTAL LOCATION SUBSTATION PLANT		**$ 104,364,364**	**$ (23,657,812)**	**$ 80,706,552**				**$ 7,520,670**						**$ 11,512,541**	**$ (3,991,870)**
PLANT NOT STUDIED															
C11501	Land, Owned In Fee Simple	$ 327,178,151	$ -	$ 327,178,151											
C11601	Land Rights, Conversion Only	$ 3,378,871	$ -	$ 3,378,871											
C11602	Easement / Right-Of-Way	$ 233,829,497	$ -	$ 233,829,497											
C11604	Land Rights, Other	$ 34,758,253	$ -	$ 34,758,253											
C45103	Leased Transmission Line	$ 517,071	$ (31,059)	$ 486,012											
C59502	Street Lights, Distribution, Leased	$ 85,311	$ (15,534)	$ 69,777											
C81799	Misc. Access, Conversion Only	$ 1,941	$ -	$ 1,941											
C87001	Pcb Solids Destruction Plant	$ -	$ -	$ -											
C95010	Right-of-Use Land and Building	$ 32,557,520	$ (8,704,716)	$ 23,852,804											
C95020	Right-of-Use Generation assets	$ 1,981,424,561	$ (614,688,455)	$ 1,366,736,107											
C99611	Columbia River Treaty	$ 97,072,039	$ (5,200,288)	$ 91,871,751											
H00001	Investment Property - Land	$ 3,247,071	$ -	$ 3,247,071											
H00003	Held for Sale - Equipment & Building	$ 1,830,015	$ (557,928)	$ 1,272,087											
H00004	Held For Sale - Land	$ 492,738	$ 0	$ 492,738											
TOTAL PLANT NOT STUDIED		**$ 2,716,373,040**	**$ (629,197,979)**	**$ 1,759,996,909**											
TOTAL PLANT IN SERVICE		**$ 28,174,477,022**	**$ (3,098,635,915)**	**$ 24,748,690,202**				**$ 873,399,684**						**$ 872,180,690**	**$ 1,218,995**

* The depreciation rates are implied in that they are based on the whole life of the asset class and would be applicable to the original cost (pre-IFRS deemed cost adjustments) of assets. As BC Hydro calculates Depreciation in its financial system by dividing the asset net book value by the remaining life of the asset, the useful lives rather than depreciation rates are applicable for BC Hydro

** Estimated fiscal 2023 Depreciation Expense based on assets in service as of March 31,2021

BC Hydro Power Authority

TABLE 2 - ORIGINAL COST, ACCRUED DEPRECIATION, AND NET BOOK VALUE RELATED TO UTILITY PLANT AS OF MARCH 31, 2020 DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Description	March 31, 2020 Original Cost	March 31, 2020 Accrued Depreciation	March 31, 2020 Net Book Value	Economic Planning Horizon	Remaining Life	Current Depreciation Expense**	Recommended Depreciation Expense for Life**	Change in Depreciation Expense**
BALFOUR	$ 695,985	$ (77,231)	$ 618,754	2023	3	$ 31,596	$ 293,579	$ (261,983)
BURRARD	$ 41,581,142	$ (16,163,832)	$ 25,417,310	2025	5	$ 4,978,596	$ 4,978,596	$ -
COQUITLAM	$ 1,821,827	$ (352,034)	$ 1,469,793	2022	2	$ 130,828	$ -	$ 130,828
DAL GRAUER	$ 9,246,034	$ (1,180,905)	$ 8,065,129	2035	15	$ 394,028	$ 615,376	$ (221,348)
FAIRMONT	$ 182,657	$ (26,431)	$ 156,226	2024	4	$ 8,302	$ 47,025	$ (38,724)
FORT STEELE	$ 223,379	$ (21,639)	$ 201,739	2022	2	$ 7,213	$ -	$ 7,213
GEORGE DICKIE	$ 827,445	$ (105,468)	$ 721,977	2023	3	$ 34,001	$ 332,559	$ (298,558)
GLENMORE	$ 732,660	$ (120,899)	$ 611,761	2024	4	$ 39,729	$ 184,211	$ (144,482)
HORNE PAYNE	$ 2,231,824	$ (204,863)	$ 2,026,961	2025	5	$ 89,253	$ 486,324	$ (397,071)
LOUGHEED	$ 3,181,981	$ (324,719)	$ 2,857,262	2024	4	$ 128,668	$ 905,999	$ (777,331)
MURRIN	$ 27,830,675	$ (2,901,774)	$ 24,928,901	2035	15	$ 971,939	$ 1,845,899	$ (873,960)
MURRIN #1 DAL GRAUER CIRCUIT	$ 1,383,472	$ (403,410)	$ 980,062	2033	13	$ 120,256	$ 128,043	$ (7,787)
NORGATE	$ 2,216,867	$ (324,571)	$ 1,892,295	2024	4	$ 109,258	$ 591,486	$ (482,228)
QUESNEL	$ 3,054,408	$ (395,441)	$ 2,658,967	2022	2	$ 138,217	$ -	$ 138,217
RICHMOND	$ 195,035	$ (28,419)	$ 166,616	2024	4	$ 14,358	$ 50,753	$ (36,395)
SCOTT ROAD	$ 483,591	$ (78,429)	$ 405,162	2023	3	$ 24,364	$ 185,247	$ (160,883)
SUMAS WAY	$ 578,105	$ (145,938)	$ 432,167	2024	4	$ 46,125	$ 126,550	$ (80,425)
SURREY	$ 1,859,797	$ (271,709)	$ 1,588,088	2022	2	$ 88,243	$ -	$ 88,243
WILSEY DAM	$ 6,037,481	$ (530,100)	$ 5,507,381	2029	9	$ 165,699	$ 740,893	$ (575,195)
TOTAL	**$ 104,364,364**	**$ (23,657,812)**	**$ 80,706,552**			**$ 7,520,670**	**$ 11,512,541**	**$ (3,991,870)**

** Estimated fiscal 2023 Depreciation Expense based on assets in service as of March 31,2021

BC Hydro Power Authority

TABLE 3 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF MARCH 31, 2020 DEPRECIATION RELATED TO RECOVERY OF COST OF REMOVAL

Description	March 31, 2020 NBV	Recommended Net Salvage	Recommended Annual Net Salvage Expense
Generation Plant	$ 3,417,738,901	1.10	$ 7,132,112
Transmission Plant	$ 5,386,391,816	1.30	$ 31,312,646
Distribution Plant	$ 6,474,894,365	1.20	$ 31,817,334
General Plant	$ 4,802,177,002	1.05	$ 7,517,300
TOTAL	**$ 20,081,202,085**		**$ 77,779,393**

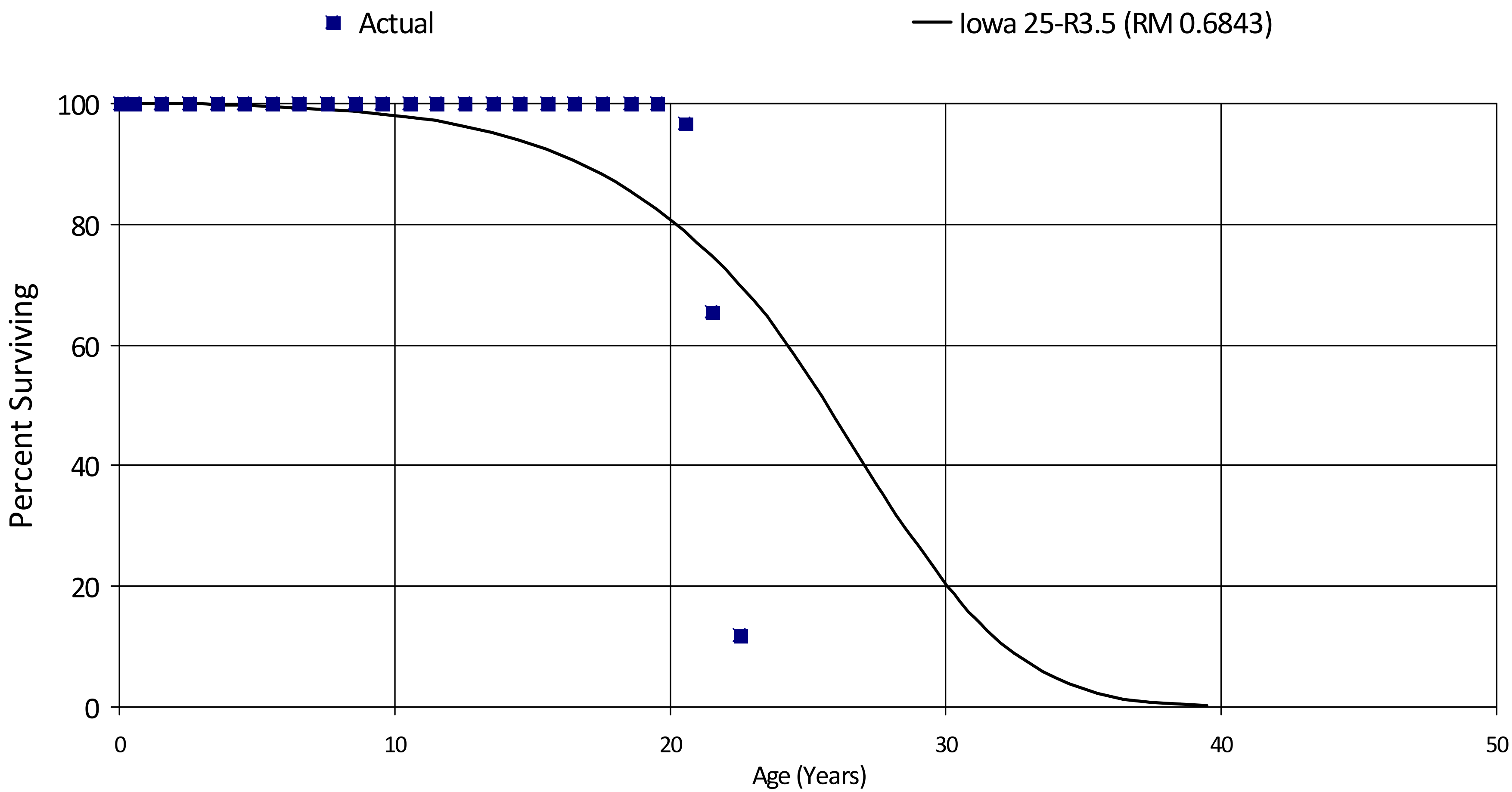
5 RETIREMENT RATE ANALYSIS

BC Hydro Power Authority

Account 11801 - Recreation Facilities

Placement Band - 1991 - 2019 Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 11801 - Recreation Facilities

Placement Band - 1991 - 2019   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

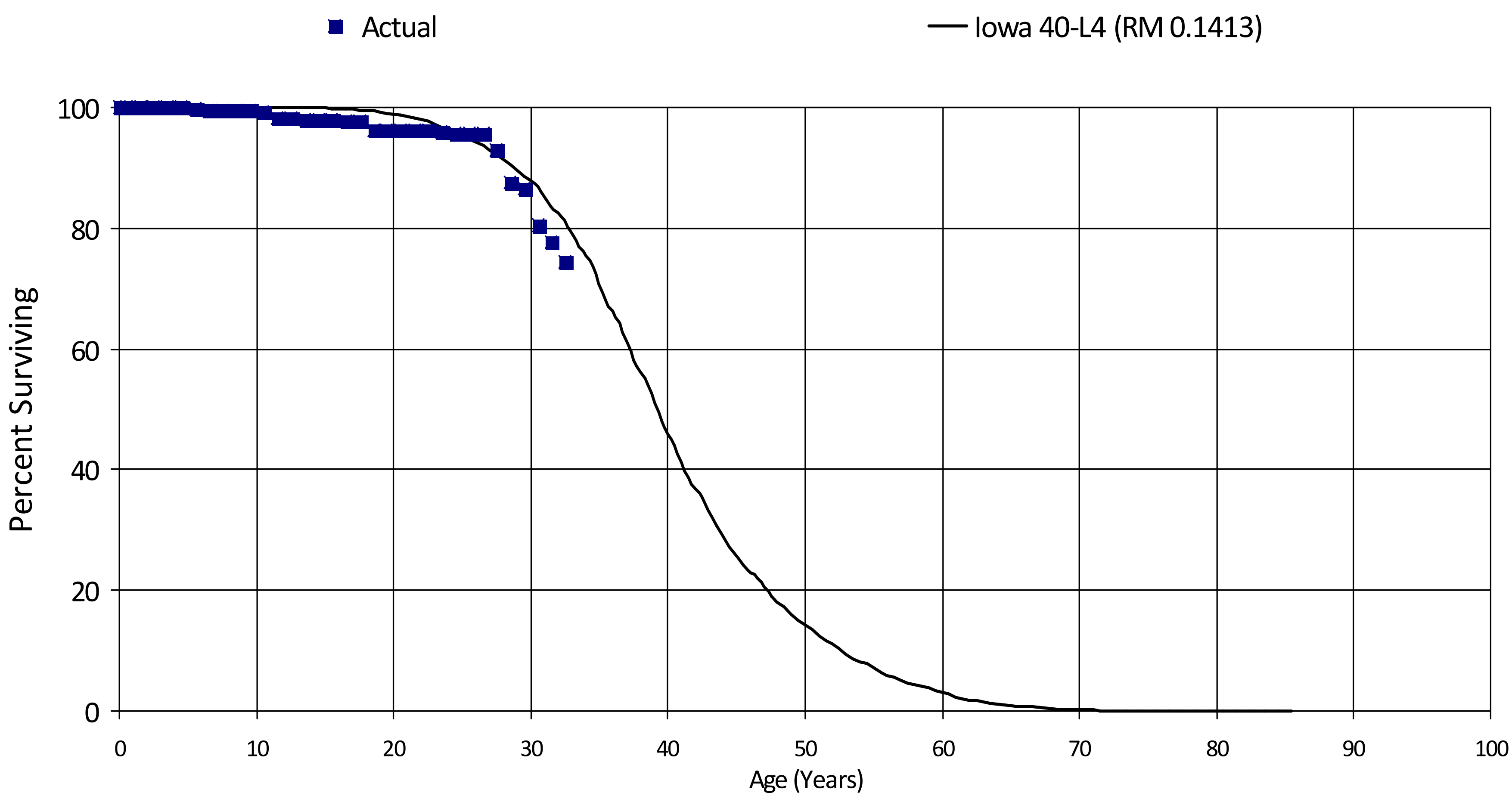
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	3,270,437	0	0.00000	1.00000	100.00
0.5	3,270,437	0	0.00000	1.00000	100.00
1.5	2,619,060	0	0.00000	1.00000	100.00
2.5	2,619,060	0	0.00000	1.00000	100.00
3.5	2,619,060	0	0.00000	1.00000	100.00
4.5	2,619,060	0	0.00000	1.00000	100.00
5.5	2,614,638	0	0.00000	1.00000	100.00
6.5	2,350,628	0	0.00000	1.00000	100.00
7.5	2,350,628	0	0.00000	1.00000	100.00
8.5	2,350,628	0	0.00000	1.00000	100.00
9.5	2,334,787	0	0.00000	1.00000	100.00
10.5	2,146,551	0	0.00000	1.00000	100.00
11.5	2,146,551	0	0.00000	1.00000	100.00
12.5	1,827,329	0	0.00000	1.00000	100.00
13.5	1,827,329	0	0.00000	1.00000	100.00
14.5	1,794,933	0	0.00000	1.00000	100.00
15.5	1,794,933	0	0.00000	1.00000	100.00
16.5	1,794,933	0	0.00000	1.00000	100.00
17.5	1,695,349	0	0.00000	1.00000	100.00
18.5	1,519,104	641	0.00042	0.99958	100.00
19.5	1,262,807	42,641	0.03377	0.96623	99.96
20.5	1,124,533	362,387	0.32226	0.67774	96.58
21.5	762,146	624,013	0.81876	0.18124	65.46
22.5	138,133	138,133	1.00000		11.86
	Totals:	1,167,815			

BC Hydro Power Authority

Account 11901 - Surfacing, Yard

Placement Band - 1976 - 2020 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 11901 - Surfacing, Yard

Placement Band - 1976 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	130,793,795	0	0.00000	1.00000	100.00
0.5	128,803,683	0	0.00000	1.00000	100.00
1.5	122,902,583	0	0.00000	1.00000	100.00
2.5	114,864,299	0	0.00000	1.00000	100.00
3.5	107,070,942	8,665	0.00008	0.99992	100.00
4.5	90,454,661	114,949	0.00127	0.99873	99.99
5.5	69,391,653	238,739	0.00344	0.99656	99.86
6.5	56,930,510	0	0.00000	1.00000	99.52
7.5	49,784,090	0	0.00000	1.00000	99.52
8.5	37,842,177	0	0.00000	1.00000	99.52
9.5	28,490,869	94,156	0.00330	0.99670	99.52
10.5	15,894,583	141,437	0.00890	0.99110	99.19
11.5	14,998,630	0	0.00000	1.00000	98.31
12.5	8,178,073	31,783	0.00389	0.99611	98.31
13.5	7,084,219	0	0.00000	1.00000	97.93
14.5	6,491,013	0	0.00000	1.00000	97.93
15.5	6,023,570	13,043	0.00217	0.99783	97.93
16.5	4,969,269	5,774	0.00116	0.99884	97.72
17.5	4,104,027	61,557	0.01500	0.98500	97.61
18.5	3,844,849	0	0.00000	1.00000	96.15
19.5	3,758,998	0	0.00000	1.00000	96.15
20.5	3,627,192	0	0.00000	1.00000	96.15
21.5	3,247,832	0	0.00000	1.00000	96.15
22.5	3,196,917	3,596	0.00112	0.99888	96.15
23.5	3,075,769	8,391	0.00273	0.99727	96.04
24.5	2,794,716	0	0.00000	1.00000	95.78
25.5	2,293,934	0	0.00000	1.00000	95.78
26.5	2,110,538	63,668	0.03017	0.96983	95.78

BC Hydro Power Authority

Account 11901 - Surfacing, Yard

Placement Band - 1976 - 2020   Experience Band - 2013 - 2020

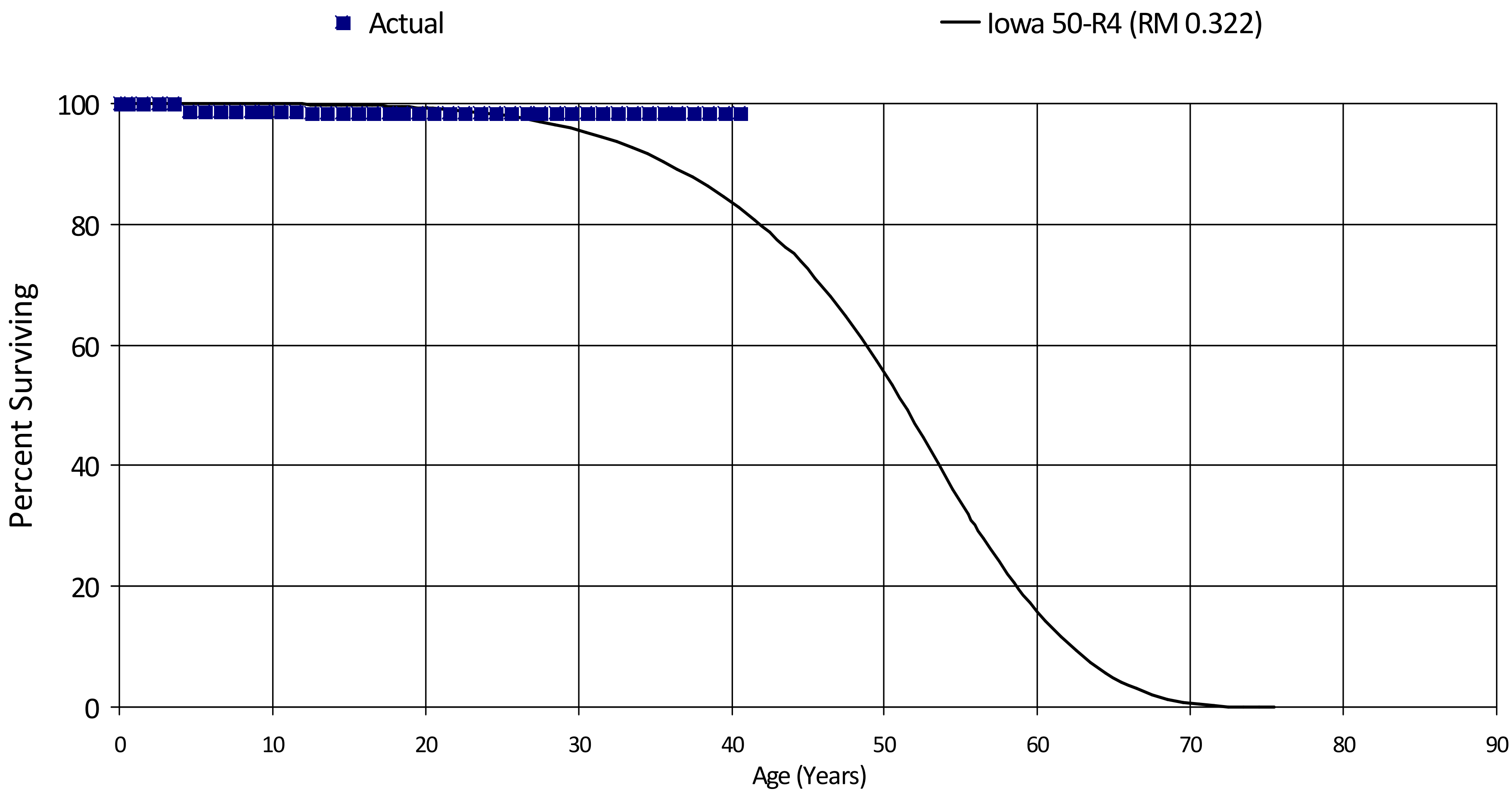
27.5	2,046,533	118,557	0.05793	0.94207	92.89
28.5	1,927,976	20,424	0.01059	0.98941	87.51
29.5	1,907,552	133,628	0.07005	0.92995	86.58
30.5	1,773,924	65,476	0.03691	0.96309	80.52
31.5	1,708,448	72,284	0.04231	0.95769	77.55
32.5	1,636,164	359,275	0.21958	0.78042	74.27
	Totals:	1,555,402			

BC Hydro Power Authority

Account 12401 - Drainage System, Yard

Placement Band - 1963 - 2020   Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 12401 - Drainage System, Yard

Placement Band - 1963 - 2020   Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	32,065,729	0	0.00000	1.00000	100.00
0.5	31,939,007	0	0.00000	1.00000	100.00
1.5	28,777,687	0	0.00000	1.00000	100.00
2.5	23,678,504	0	0.00000	1.00000	100.00
3.5	19,513,860	270,411	0.01386	0.98614	100.00
4.5	16,223,881	0	0.00000	1.00000	98.61
5.5	11,170,338	0	0.00000	1.00000	98.61
6.5	10,439,035	0	0.00000	1.00000	98.61
7.5	9,403,600	0	0.00000	1.00000	98.61
8.5	8,741,825	0	0.00000	1.00000	98.61
9.5	7,616,749	0	0.00000	1.00000	98.61
10.5	6,835,325	0	0.00000	1.00000	98.61
11.5	6,515,725	6,720	0.00103	0.99897	98.61
12.5	5,920,645	0	0.00000	1.00000	98.51
13.5	5,043,714	0	0.00000	1.00000	98.51
14.5	4,981,160	0	0.00000	1.00000	98.51
15.5	4,524,636	0	0.00000	1.00000	98.51
16.5	4,466,260	0	0.00000	1.00000	98.51
17.5	4,266,926	0	0.00000	1.00000	98.51
18.5	4,266,137	0	0.00000	1.00000	98.51
19.5	4,266,137	0	0.00000	1.00000	98.51
20.5	4,123,310	0	0.00000	1.00000	98.51
21.5	4,056,586	0	0.00000	1.00000	98.51
22.5	4,026,448	0	0.00000	1.00000	98.51
23.5	4,017,136	0	0.00000	1.00000	98.51
24.5	3,928,389	0	0.00000	1.00000	98.51
25.5	3,853,669	0	0.00000	1.00000	98.51
26.5	3,807,101	0	0.00000	1.00000	98.51

BC Hydro Power Authority

Account 12401 - Drainage System, Yard

Placement Band - 1963 - 2020   Experience Band - 2014 - 2020

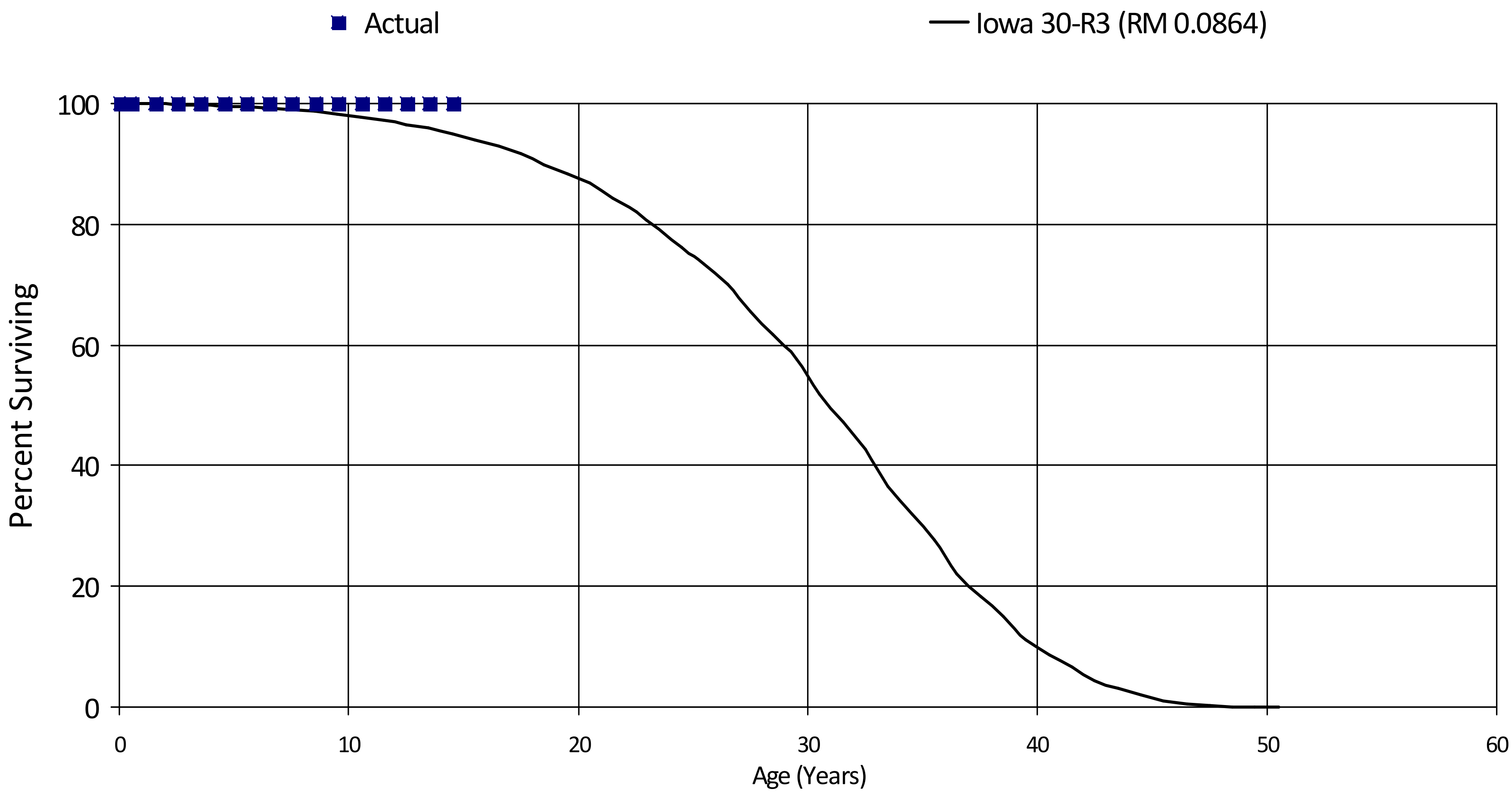
27.5	3,807,101	0	0.00000	1.00000	98.51
28.5	3,807,101	0	0.00000	1.00000	98.51
29.5	3,807,101	0	0.00000	1.00000	98.51
30.5	3,719,417	0	0.00000	1.00000	98.51
31.5	3,712,787	0	0.00000	1.00000	98.51
32.5	3,712,787	0	0.00000	1.00000	98.51
33.5	3,712,787	0	0.00000	1.00000	98.51
34.5	3,702,662	0	0.00000	1.00000	98.51
35.5	531,734	0	0.00000	1.00000	98.51
36.5	519,686	0	0.00000	1.00000	98.51
37.5	515,316	0	0.00000	1.00000	98.51
38.5	489,746	0	0.00000	1.00000	98.51
39.5	416,579	0	0.00000	1.00000	98.51
40.5	403,145	0	0.00000	1.00000	98.51
	Totals:	277,131			

BC Hydro Power Authority

Account 12402 - Landscaping

Placement Band - 1997 - 2019   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 12402 - Landscaping

Placement Band - 1997 - 2019   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

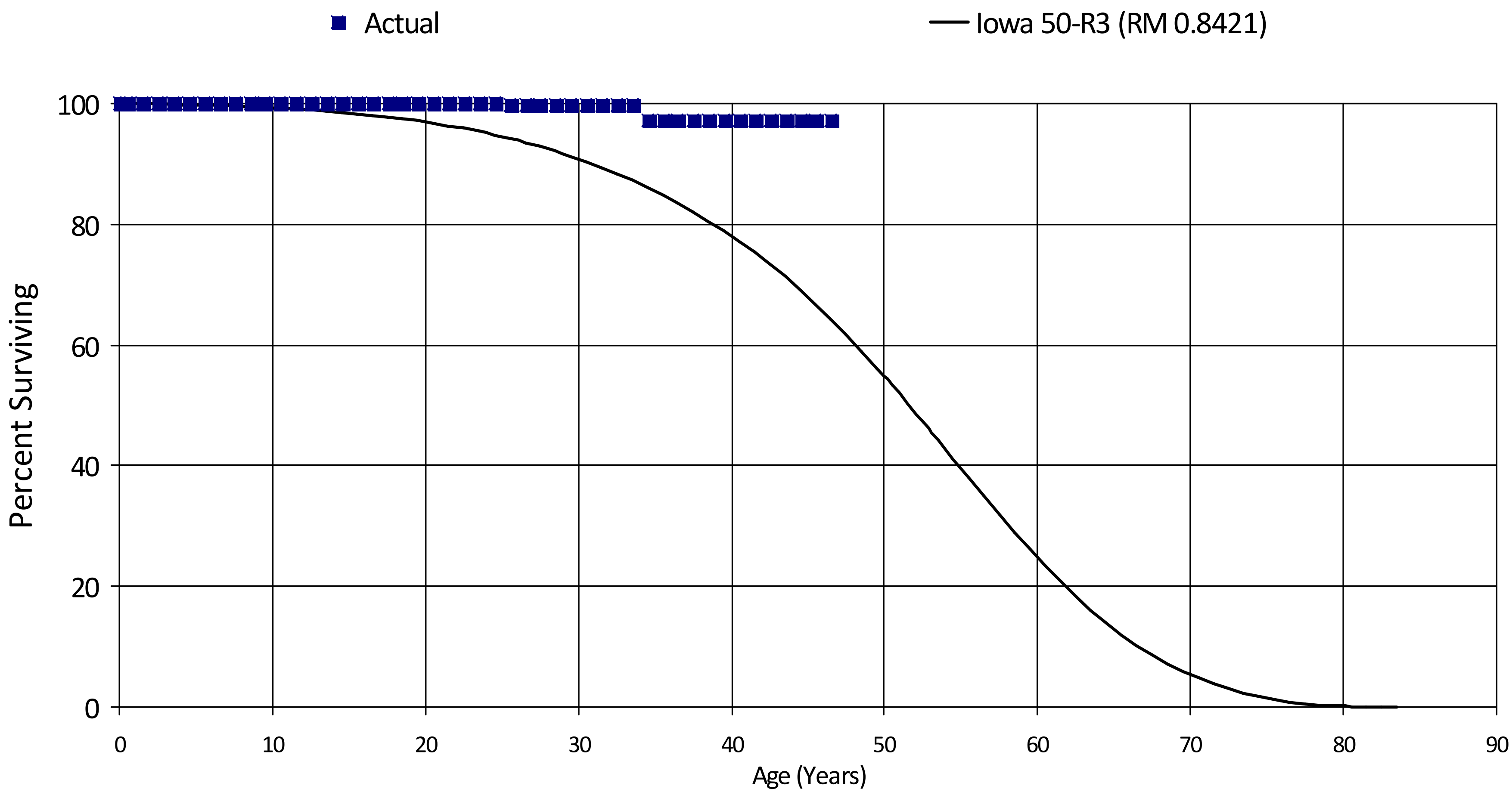
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	17,058,483	0	0.00000	1.00000	100.00
0.5	17,058,483	0	0.00000	1.00000	100.00
1.5	16,171,896	0	0.00000	1.00000	100.00
2.5	14,847,451	0	0.00000	1.00000	100.00
3.5	10,815,709	0	0.00000	1.00000	100.00
4.5	9,339,699	0	0.00000	1.00000	100.00
5.5	8,554,785	0	0.00000	1.00000	100.00
6.5	4,100,544	0	0.00000	1.00000	100.00
7.5	3,051,122	0	0.00000	1.00000	100.00
8.5	2,964,792	0	0.00000	1.00000	100.00
9.5	669,370	0	0.00000	1.00000	100.00
10.5	405,504	0	0.00000	1.00000	100.00
11.5	405,500	0	0.00000	1.00000	100.00
12.5	405,500	0	0.00000	1.00000	100.00
13.5	198,805	0	0.00000	1.00000	100.00
14.5	198,069	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 12501 - Wall, Retaining, Steel

Placement Band - 1969 - 2018   Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 12501 - Wall, Retaining, Steel

Placement Band - 1969 - 2018   Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	530,467	0	0.00000	1.00000	100.00
0.5	530,467	0	0.00000	1.00000	100.00
1.5	530,467	0	0.00000	1.00000	100.00
2.5	129,708	0	0.00000	1.00000	100.00
3.5	129,708	0	0.00000	1.00000	100.00
4.5	129,708	0	0.00000	1.00000	100.00
5.5	129,708	0	0.00000	1.00000	100.00
6.5	129,708	0	0.00000	1.00000	100.00
7.5	129,708	0	0.00000	1.00000	100.00
8.5	129,708	0	0.00000	1.00000	100.00
9.5	129,708	0	0.00000	1.00000	100.00
10.5	129,708	0	0.00000	1.00000	100.00
11.5	129,708	0	0.00000	1.00000	100.00
12.5	129,708	0	0.00000	1.00000	100.00
13.5	129,708	0	0.00000	1.00000	100.00
14.5	129,708	0	0.00000	1.00000	100.00
15.5	129,708	0	0.00000	1.00000	100.00
16.5	129,708	0	0.00000	1.00000	100.00
17.5	129,708	0	0.00000	1.00000	100.00
18.5	129,708	0	0.00000	1.00000	100.00
19.5	129,708	0	0.00000	1.00000	100.00
20.5	129,708	0	0.00000	1.00000	100.00
21.5	129,708	0	0.00000	1.00000	100.00
22.5	129,708	0	0.00000	1.00000	100.00
23.5	129,708	0	0.00000	1.00000	100.00
24.5	129,708	449	0.00346	0.99654	100.00
25.5	129,259	0	0.00000	1.00000	99.65
26.5	129,259	0	0.00000	1.00000	99.65

BC Hydro Power Authority

Account 12501 - Wall, Retaining, Steel

Placement Band - 1969 - 2018   Experience Band - 2016 - 2020

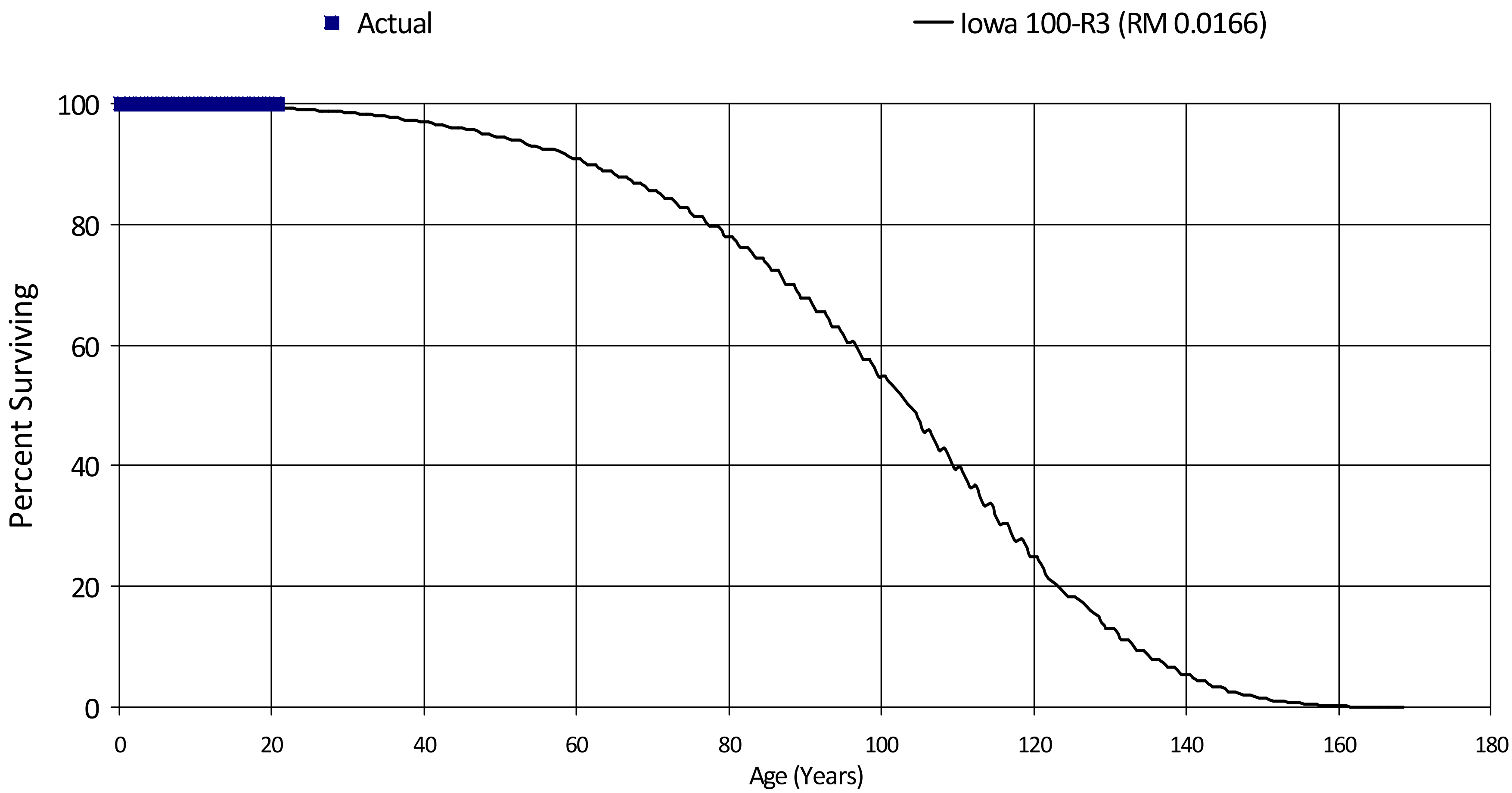
27.5	129,259	0	0.00000	1.00000	99.65
28.5	129,259	0	0.00000	1.00000	99.65
29.5	129,259	0	0.00000	1.00000	99.65
30.5	129,259	0	0.00000	1.00000	99.65
31.5	129,259	0	0.00000	1.00000	99.65
32.5	88,794	0	0.00000	1.00000	99.65
33.5	88,794	2,184	0.02460	0.97540	99.65
34.5	86,611	0	0.00000	1.00000	97.20
35.5	55,829	0	0.00000	1.00000	97.20
36.5	55,829	0	0.00000	1.00000	97.20
37.5	55,829	0	0.00000	1.00000	97.20
38.5	23,011	0	0.00000	1.00000	97.20
39.5	23,011	0	0.00000	1.00000	97.20
40.5	23,011	0	0.00000	1.00000	97.20
41.5	23,011	0	0.00000	1.00000	97.20
42.5	23,011	0	0.00000	1.00000	97.20
43.5	23,011	0	0.00000	1.00000	97.20
44.5	22,615	0	0.00000	1.00000	97.20
45.5	14,017	0	0.00000	1.00000	97.20
46.5	14,017	0	0.00000	1.00000	97.20
	Totals:	2,633			

BC Hydro Power Authority

Account 12502 - Wall, Retaining, Concrete

Placement Band - 1995 - 2019 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 12502 - Wall, Retaining, Concrete

Placement Band - 1995 - 2019 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

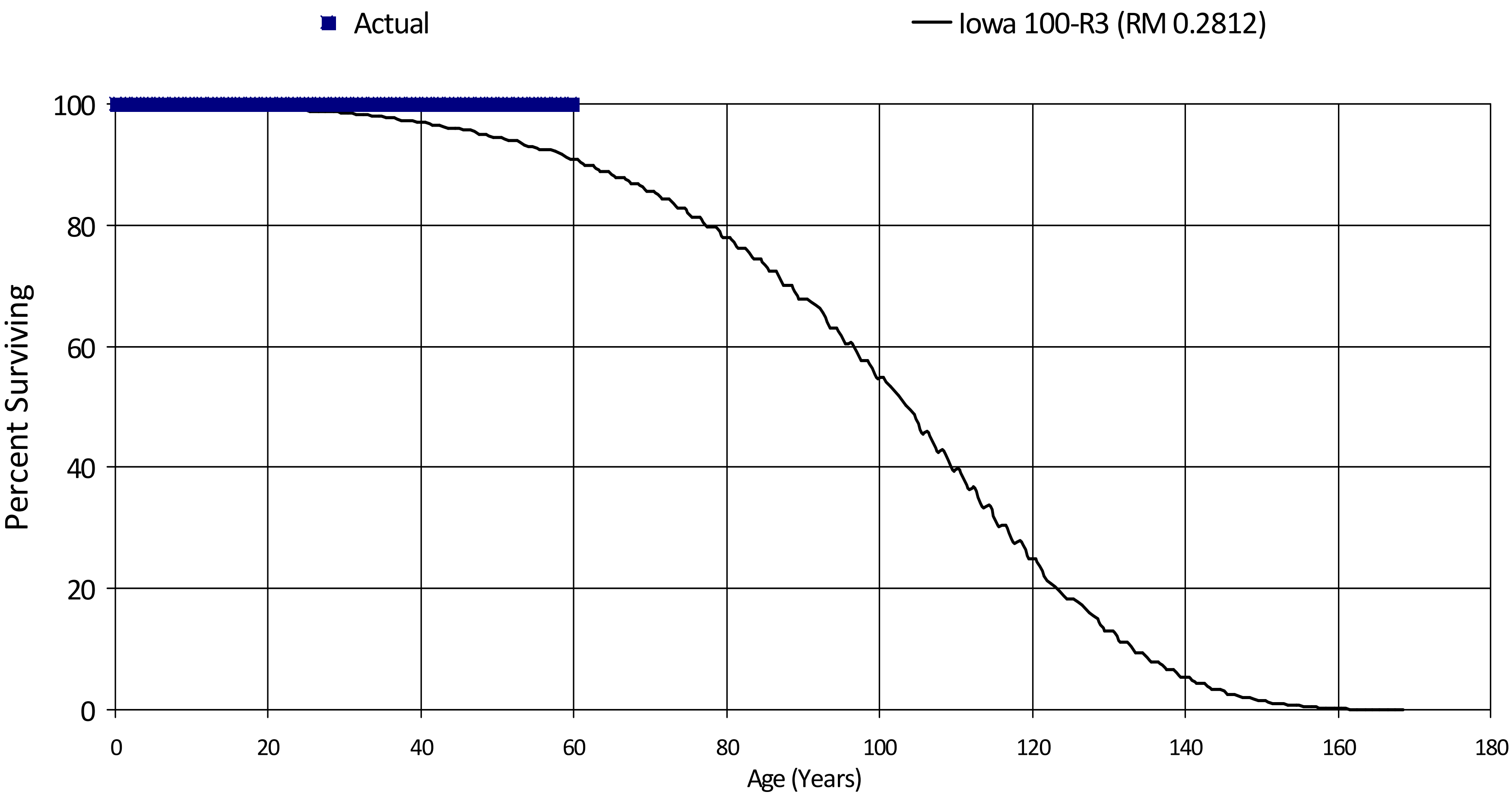
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	15,981,218	0	0.00000	1.00000	100.00
0.5	15,981,218	0	0.00000	1.00000	100.00
1.5	12,496,923	0	0.00000	1.00000	100.00
2.5	12,496,923	0	0.00000	1.00000	100.00
3.5	12,100,490	0	0.00000	1.00000	100.00
4.5	11,640,406	0	0.00000	1.00000	100.00
5.5	11,579,584	0	0.00000	1.00000	100.00
6.5	11,530,849	0	0.00000	1.00000	100.00
7.5	11,430,014	0	0.00000	1.00000	100.00
8.5	11,266,438	0	0.00000	1.00000	100.00
9.5	11,009,944	0	0.00000	1.00000	100.00
10.5	9,842,270	0	0.00000	1.00000	100.00
11.5	9,726,051	0	0.00000	1.00000	100.00
12.5	9,632,582	0	0.00000	1.00000	100.00
13.5	303,513	0	0.00000	1.00000	100.00
14.5	248,829	0	0.00000	1.00000	100.00
15.5	248,829	0	0.00000	1.00000	100.00
16.5	248,829	0	0.00000	1.00000	100.00
17.5	225,707	0	0.00000	1.00000	100.00
18.5	225,707	0	0.00000	1.00000	100.00
19.5	171,978	0	0.00000	1.00000	100.00
20.5	171,978	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 21001 - Dam, Embankment / Concrete

Placement Band - 1929 - 2020 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 21001 - Dam, Embankment / Concrete

Placement Band - 1929 - 2020   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,720,450,012	0	0.00000	1.00000	100.00
0.5	2,719,646,130	0	0.00000	1.00000	100.00
1.5	2,719,646,130	0	0.00000	1.00000	100.00
2.5	2,714,756,971	0	0.00000	1.00000	100.00
3.5	2,700,077,508	0	0.00000	1.00000	100.00
4.5	2,698,388,740	0	0.00000	1.00000	100.00
5.5	2,665,399,892	0	0.00000	1.00000	100.00
6.5	2,665,399,892	0	0.00000	1.00000	100.00
7.5	2,664,079,759	0	0.00000	1.00000	100.00
8.5	2,664,079,759	0	0.00000	1.00000	100.00
9.5	2,660,479,952	0	0.00000	1.00000	100.00
10.5	1,205,466,719	0	0.00000	1.00000	100.00
11.5	1,205,466,719	0	0.00000	1.00000	100.00
12.5	1,158,078,340	0	0.00000	1.00000	100.00
13.5	1,158,078,340	0	0.00000	1.00000	100.00
14.5	1,155,501,285	0	0.00000	1.00000	100.00
15.5	1,141,338,879	0	0.00000	1.00000	100.00
16.5	1,141,338,879	0	0.00000	1.00000	100.00
17.5	1,141,338,879	0	0.00000	1.00000	100.00
18.5	1,139,973,686	0	0.00000	1.00000	100.00
19.5	1,139,973,686	0	0.00000	1.00000	100.00
20.5	1,139,973,686	0	0.00000	1.00000	100.00
21.5	1,139,973,686	0	0.00000	1.00000	100.00
22.5	1,139,726,391	0	0.00000	1.00000	100.00
23.5	1,139,726,391	0	0.00000	1.00000	100.00
24.5	1,139,726,391	0	0.00000	1.00000	100.00
25.5	1,139,628,283	0	0.00000	1.00000	100.00
26.5	1,139,298,824	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 21001 - Dam, Embankment / Concrete

Placement Band - 1929 - 2020   Experience Band - 2020 - 2020

27.5	1,139,298,824	0	0.00000	1.00000	100.00
28.5	1,129,312,302	0	0.00000	1.00000	100.00
29.5	1,129,043,540	0	0.00000	1.00000	100.00
30.5	1,129,043,540	0	0.00000	1.00000	100.00
31.5	1,128,816,890	0	0.00000	1.00000	100.00
32.5	1,128,310,426	0	0.00000	1.00000	100.00
33.5	1,112,718,708	0	0.00000	1.00000	100.00
34.5	1,112,718,708	0	0.00000	1.00000	100.00
35.5	355,102,303	0	0.00000	1.00000	100.00
36.5	353,747,799	0	0.00000	1.00000	100.00
37.5	353,747,799	0	0.00000	1.00000	100.00
38.5	353,747,799	0	0.00000	1.00000	100.00
39.5	296,850,640	0	0.00000	1.00000	100.00
40.5	213,304,231	0	0.00000	1.00000	100.00
41.5	213,304,231	0	0.00000	1.00000	100.00
42.5	213,304,231	0	0.00000	1.00000	100.00
43.5	191,886,562	0	0.00000	1.00000	100.00
44.5	191,662,363	0	0.00000	1.00000	100.00
45.5	191,662,363	0	0.00000	1.00000	100.00
46.5	191,662,363	0	0.00000	1.00000	100.00
47.5	190,363,724	0	0.00000	1.00000	100.00
48.5	188,349,917	0	0.00000	1.00000	100.00
49.5	188,276,965	0	0.00000	1.00000	100.00
50.5	188,276,965	0	0.00000	1.00000	100.00
51.5	90,826,383	0	0.00000	1.00000	100.00
52.5	88,577,563	0	0.00000	1.00000	100.00
53.5	83,989,373	0	0.00000	1.00000	100.00
54.5	83,989,373	0	0.00000	1.00000	100.00
55.5	69,694,276	0	0.00000	1.00000	100.00
56.5	57,246,457	0	0.00000	1.00000	100.00
57.5	43,590,453	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 21001 - Dam, Embankment / Concrete

Placement Band - 1929 - 2020 Experience Band - 2020 - 2020

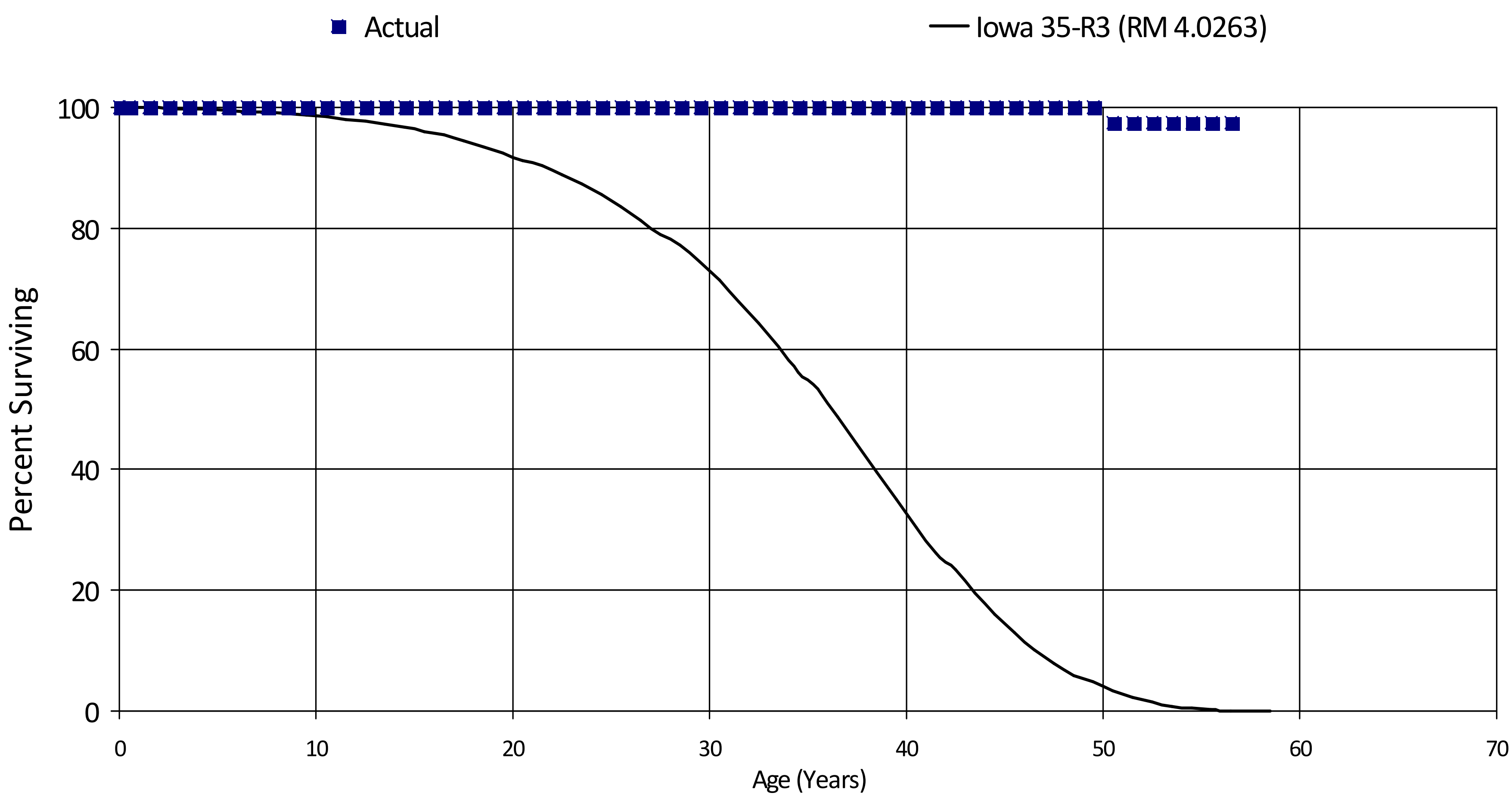
58.5	43,590,453	0	0.00000	1.00000	100.00
59.5	43,590,453	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 21002 - Dam, Crib, Wooden

Placement Band - 1963 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 21002 - Dam, Crib, Wooden

Placement Band - 1963 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	516,401	0	0.00000	1.00000	100.00
0.5	516,401	0	0.00000	1.00000	100.00
1.5	516,401	0	0.00000	1.00000	100.00
2.5	516,401	0	0.00000	1.00000	100.00
3.5	516,401	0	0.00000	1.00000	100.00
4.5	516,401	0	0.00000	1.00000	100.00
5.5	516,401	0	0.00000	1.00000	100.00
6.5	516,401	0	0.00000	1.00000	100.00
7.5	516,401	0	0.00000	1.00000	100.00
8.5	516,401	0	0.00000	1.00000	100.00
9.5	516,401	0	0.00000	1.00000	100.00
10.5	516,401	0	0.00000	1.00000	100.00
11.5	516,401	0	0.00000	1.00000	100.00
12.5	516,401	0	0.00000	1.00000	100.00
13.5	516,401	0	0.00000	1.00000	100.00
14.5	516,401	0	0.00000	1.00000	100.00
15.5	516,401	0	0.00000	1.00000	100.00
16.5	516,401	0	0.00000	1.00000	100.00
17.5	516,401	0	0.00000	1.00000	100.00
18.5	516,401	0	0.00000	1.00000	100.00
19.5	516,401	0	0.00000	1.00000	100.00
20.5	516,401	0	0.00000	1.00000	100.00
21.5	516,401	0	0.00000	1.00000	100.00
22.5	516,401	0	0.00000	1.00000	100.00
23.5	516,401	0	0.00000	1.00000	100.00
24.5	516,401	0	0.00000	1.00000	100.00
25.5	516,401	0	0.00000	1.00000	100.00
26.5	516,401	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 21002 - Dam, Crib, Wooden

Placement Band - 1963 - 2020   Experience Band - 2013 - 2020

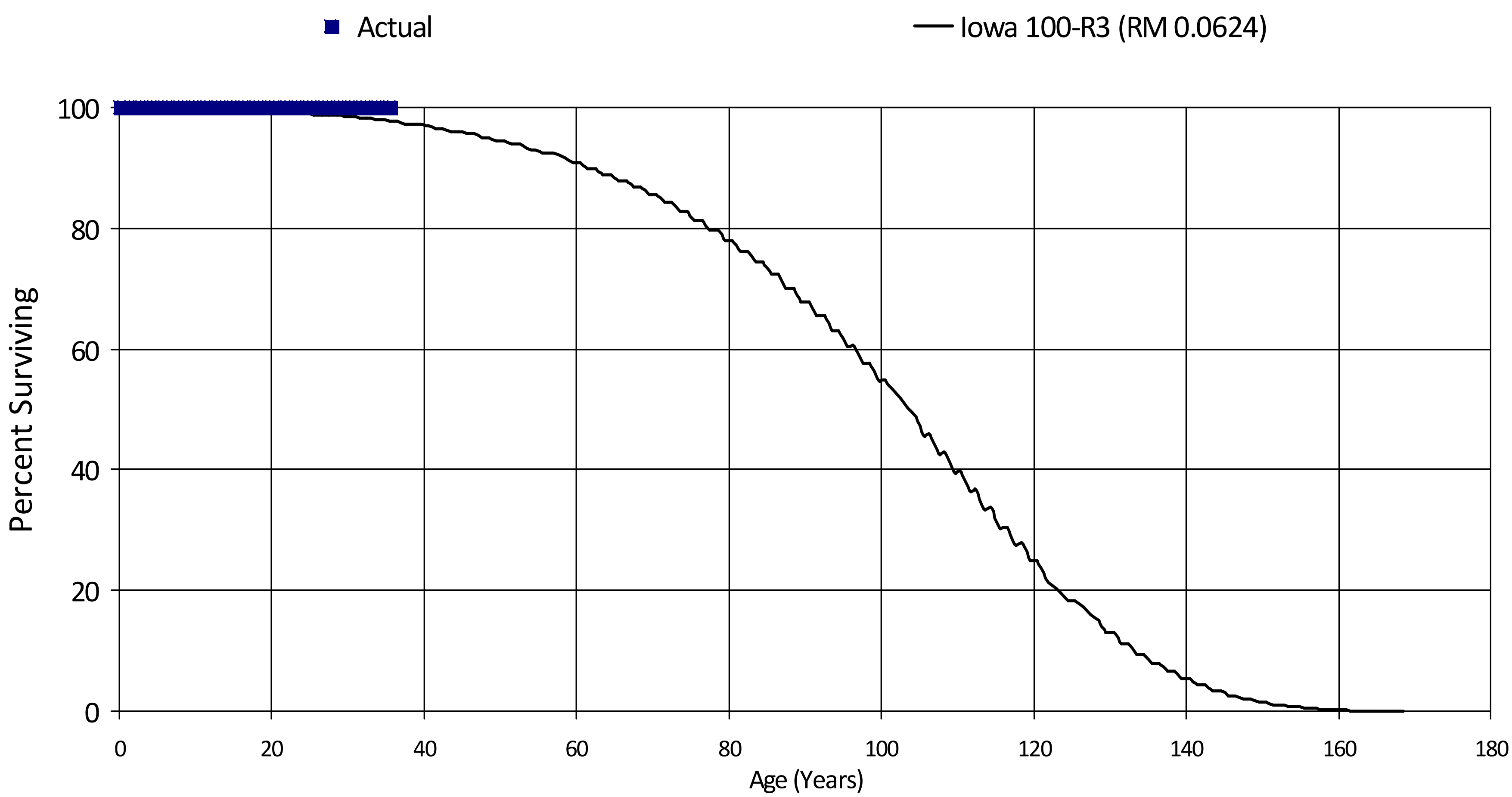
27.5	489,165	0	0.00000	1.00000	100.00
28.5	489,165	0	0.00000	1.00000	100.00
29.5	489,165	0	0.00000	1.00000	100.00
30.5	489,165	0	0.00000	1.00000	100.00
31.5	489,165	0	0.00000	1.00000	100.00
32.5	489,165	0	0.00000	1.00000	100.00
33.5	489,165	0	0.00000	1.00000	100.00
34.5	489,165	0	0.00000	1.00000	100.00
35.5	489,165	0	0.00000	1.00000	100.00
36.5	489,165	0	0.00000	1.00000	100.00
37.5	489,165	0	0.00000	1.00000	100.00
38.5	489,165	0	0.00000	1.00000	100.00
39.5	489,165	0	0.00000	1.00000	100.00
40.5	489,165	0	0.00000	1.00000	100.00
41.5	489,165	0	0.00000	1.00000	100.00
42.5	489,165	0	0.00000	1.00000	100.00
43.5	489,165	0	0.00000	1.00000	100.00
44.5	489,165	0	0.00000	1.00000	100.00
45.5	489,165	0	0.00000	1.00000	100.00
46.5	489,165	0	0.00000	1.00000	100.00
47.5	489,165	0	0.00000	1.00000	100.00
48.5	489,165	0	0.00000	1.00000	100.00
49.5	489,165	12,219	0.02498	0.97502	100.00
50.5	476,946	0	0.00000	1.00000	97.50
51.5	476,946	0	0.00000	1.00000	97.50
52.5	476,946	0	0.00000	1.00000	97.50
53.5	476,946	0	0.00000	1.00000	97.50
54.5	476,946	0	0.00000	1.00000	97.50
55.5	476,946	0	0.00000	1.00000	97.50
56.5	476,946	0	0.00000	1.00000	97.50
	Totals:	12,219			

BC Hydro Power Authority

Account 21101 - Dike, Protective

Placement Band - 1981 - 2013 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 21101 - Dike, Protective

Placement Band - 1981 - 2013   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	4,851,836	0	0.00000	1.00000	100.00
0.5	4,851,836	0	0.00000	1.00000	100.00
1.5	4,851,836	0	0.00000	1.00000	100.00
2.5	4,851,836	0	0.00000	1.00000	100.00
3.5	4,851,836	0	0.00000	1.00000	100.00
4.5	4,851,836	0	0.00000	1.00000	100.00
5.5	4,851,836	0	0.00000	1.00000	100.00
6.5	4,851,836	0	0.00000	1.00000	100.00
7.5	4,822,910	0	0.00000	1.00000	100.00
8.5	4,822,910	0	0.00000	1.00000	100.00
9.5	3,533,940	0	0.00000	1.00000	100.00
10.5	3,533,940	0	0.00000	1.00000	100.00
11.5	3,533,940	0	0.00000	1.00000	100.00
12.5	3,533,940	0	0.00000	1.00000	100.00
13.5	3,119,055	0	0.00000	1.00000	100.00
14.5	3,119,055	0	0.00000	1.00000	100.00
15.5	3,119,055	0	0.00000	1.00000	100.00
16.5	3,119,055	0	0.00000	1.00000	100.00
17.5	3,119,055	0	0.00000	1.00000	100.00
18.5	3,119,055	0	0.00000	1.00000	100.00
19.5	2,942,828	0	0.00000	1.00000	100.00
20.5	2,942,828	0	0.00000	1.00000	100.00
21.5	2,942,828	0	0.00000	1.00000	100.00
22.5	2,917,728	0	0.00000	1.00000	100.00
23.5	2,788,503	0	0.00000	1.00000	100.00
24.5	538,646	0	0.00000	1.00000	100.00
25.5	538,646	0	0.00000	1.00000	100.00
26.5	538,646	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 21101 - Dike, Protective

Placement Band - 1981 - 2013 Experience Band - 2020 - 2020

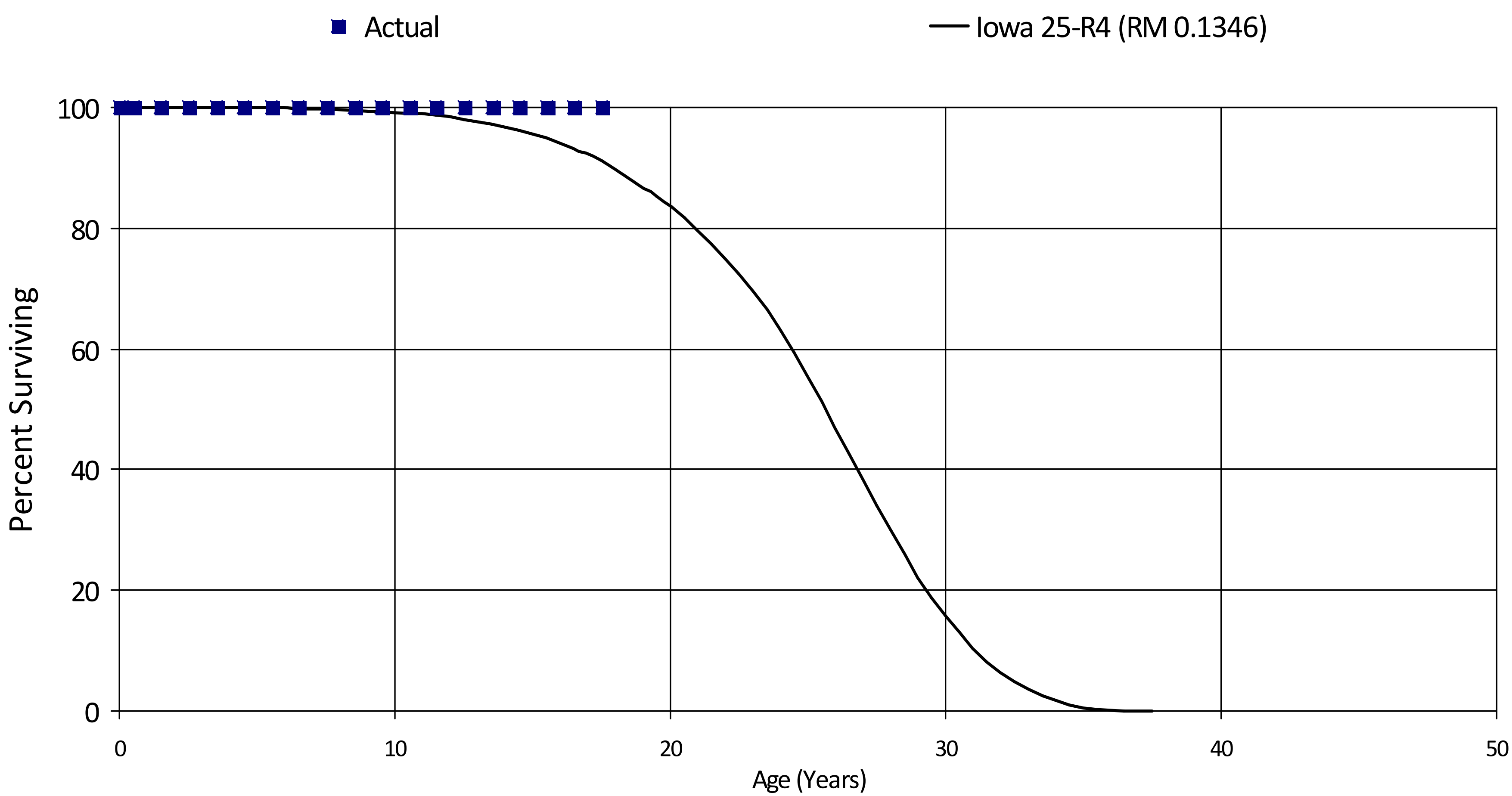
27.5	538,646	0	0.00000	1.00000	100.00
28.5	538,646	0	0.00000	1.00000	100.00
29.5	538,646	0	0.00000	1.00000	100.00
30.5	538,646	0	0.00000	1.00000	100.00
31.5	538,646	0	0.00000	1.00000	100.00
32.5	538,646	0	0.00000	1.00000	100.00
33.5	538,646	0	0.00000	1.00000	100.00
34.5	538,646	0	0.00000	1.00000	100.00
35.5	538,646	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 21102 - Erosion Donut / Bank Protection

Placement Band - 2002 - 2018   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 21102 - Erosion Donut / Bank Protection

Placement Band - 2002 - 2018   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

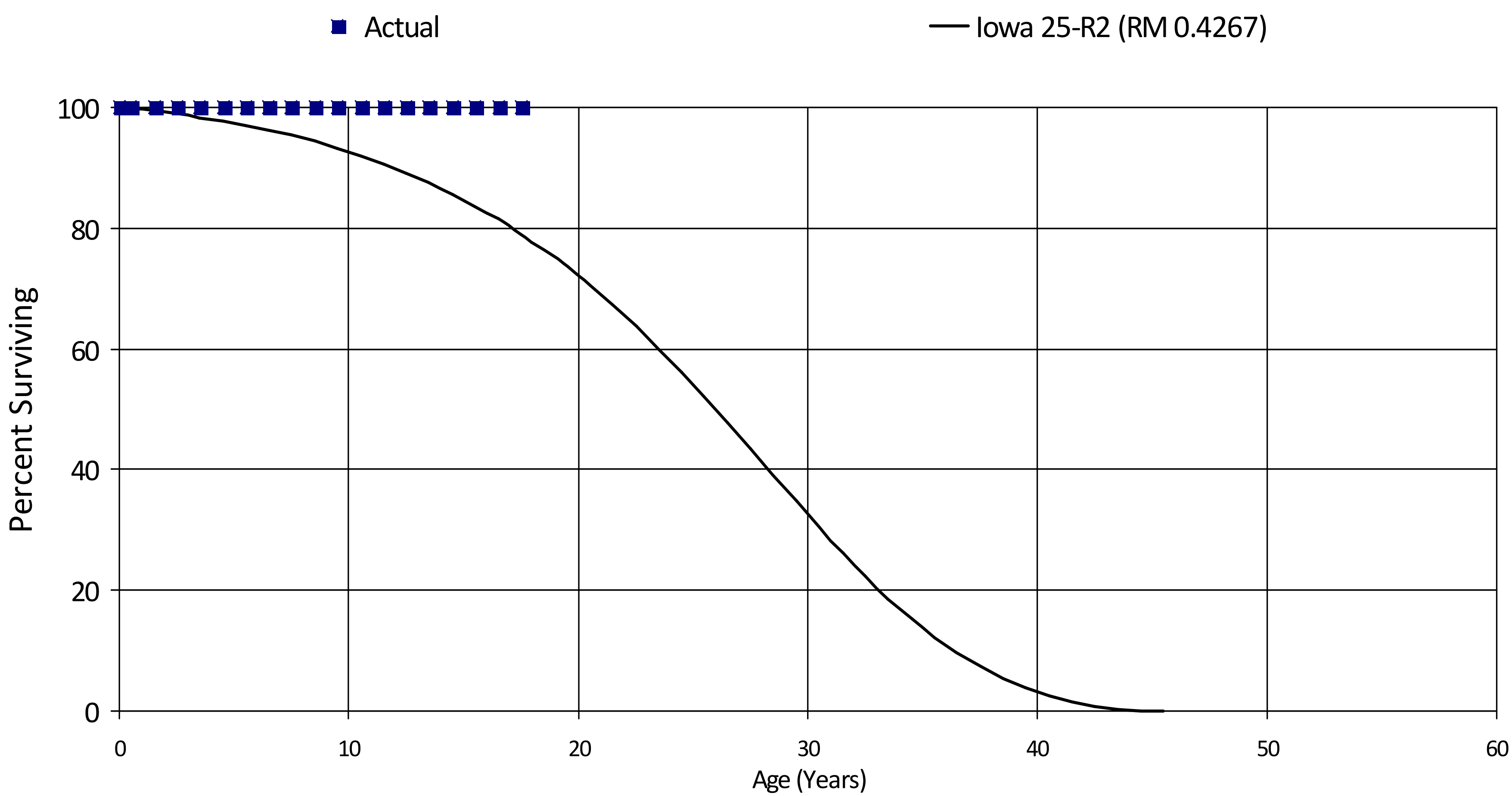
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	15,627,249	0	0.00000	1.00000	100.00
0.5	15,627,249	0	0.00000	1.00000	100.00
1.5	15,627,249	0	0.00000	1.00000	100.00
2.5	13,684,894	0	0.00000	1.00000	100.00
3.5	13,684,894	0	0.00000	1.00000	100.00
4.5	13,684,894	0	0.00000	1.00000	100.00
5.5	5,555,161	0	0.00000	1.00000	100.00
6.5	4,730,083	0	0.00000	1.00000	100.00
7.5	4,005,046	0	0.00000	1.00000	100.00
8.5	3,930,863	0	0.00000	1.00000	100.00
9.5	3,333,059	0	0.00000	1.00000	100.00
10.5	3,333,059	0	0.00000	1.00000	100.00
11.5	3,310,319	0	0.00000	1.00000	100.00
12.5	2,834,927	0	0.00000	1.00000	100.00
13.5	2,787,199	0	0.00000	1.00000	100.00
14.5	2,038,387	0	0.00000	1.00000	100.00
15.5	1,998,790	0	0.00000	1.00000	100.00
16.5	336,624	0	0.00000	1.00000	100.00
17.5	170,345	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 21103 - Debris / Avalance Deflector

Placement Band - 2002 - 2015   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 21103 - Debris / Avalance Deflector

Placement Band - 2002 - 2015   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

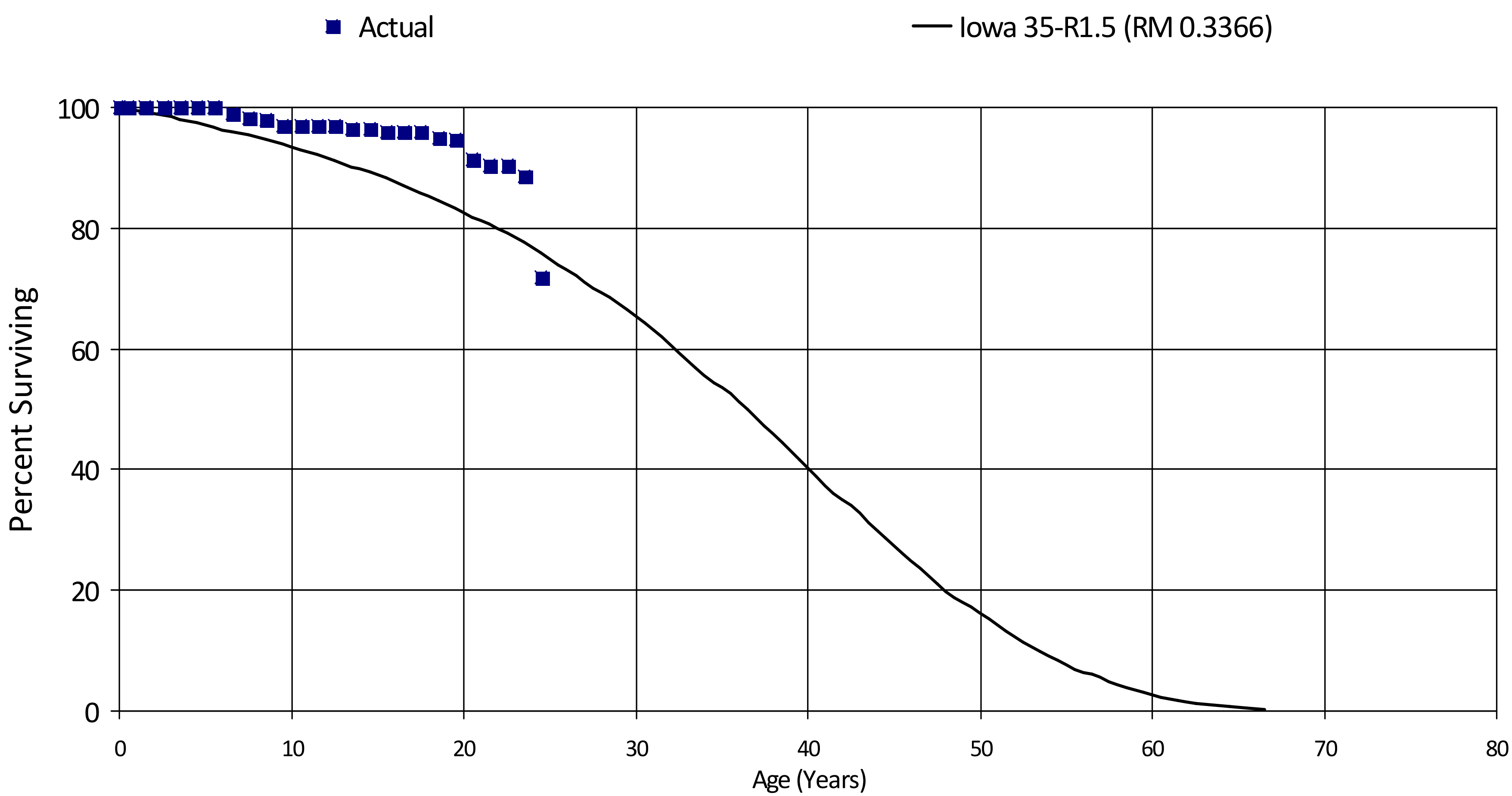
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,459,576	0	0.00000	1.00000	100.00
0.5	1,459,576	0	0.00000	1.00000	100.00
1.5	1,459,576	0	0.00000	1.00000	100.00
2.5	1,459,576	0	0.00000	1.00000	100.00
3.5	1,459,576	0	0.00000	1.00000	100.00
4.5	1,459,576	0	0.00000	1.00000	100.00
5.5	1,300,034	0	0.00000	1.00000	100.00
6.5	1,214,653	0	0.00000	1.00000	100.00
7.5	1,199,195	0	0.00000	1.00000	100.00
8.5	1,182,002	0	0.00000	1.00000	100.00
9.5	1,091,754	0	0.00000	1.00000	100.00
10.5	825,995	0	0.00000	1.00000	100.00
11.5	560,896	0	0.00000	1.00000	100.00
12.5	549,871	0	0.00000	1.00000	100.00
13.5	208,230	0	0.00000	1.00000	100.00
14.5	134,557	0	0.00000	1.00000	100.00
15.5	134,557	0	0.00000	1.00000	100.00
16.5	134,557	0	0.00000	1.00000	100.00
17.5	65,718	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 21901 - Roofs

Placement Band - 1925 - 2020 Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 21901 - Roofs

Placement Band - 1925 - 2020   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

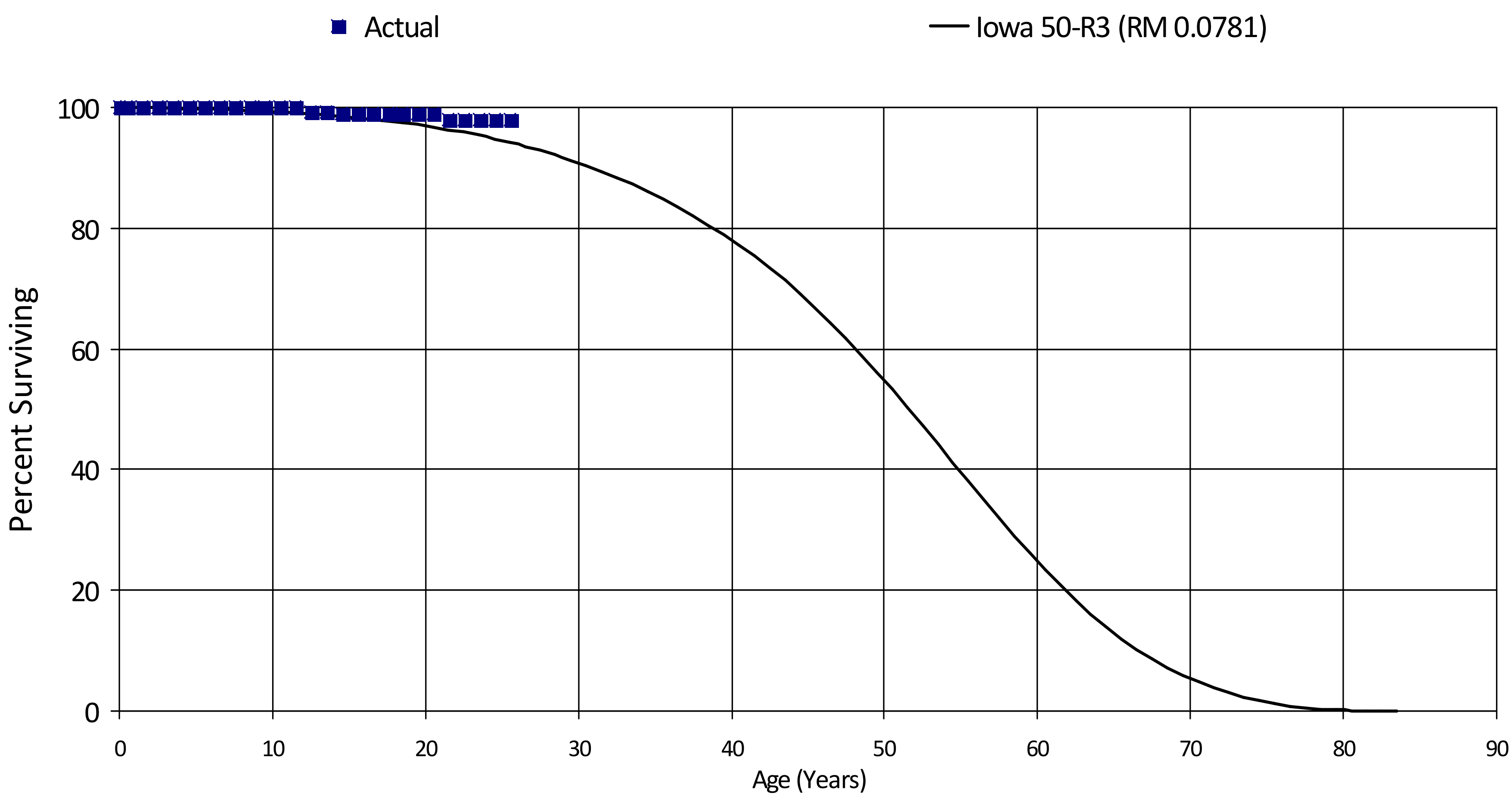
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	62,639,298	0	0.00000	1.00000	100.00
0.5	62,424,046	0	0.00000	1.00000	100.00
1.5	58,790,811	0	0.00000	1.00000	100.00
2.5	52,119,821	0	0.00000	1.00000	100.00
3.5	49,395,337	0	0.00000	1.00000	100.00
4.5	45,755,549	48,675	0.00106	0.99894	100.00
5.5	35,908,270	304,766	0.00849	0.99151	99.89
6.5	33,301,053	307,315	0.00923	0.99077	99.04
7.5	27,213,644	62,588	0.00230	0.99770	98.13
8.5	19,326,259	183,442	0.00949	0.99051	97.90
9.5	13,851,439	0	0.00000	1.00000	96.97
10.5	11,492,165	0	0.00000	1.00000	96.97
11.5	8,613,106	0	0.00000	1.00000	96.97
12.5	7,873,313	50,639	0.00643	0.99357	96.97
13.5	7,379,085	0	0.00000	1.00000	96.35
14.5	5,321,013	27,872	0.00524	0.99476	96.35
15.5	5,016,334	0	0.00000	1.00000	95.85
16.5	4,275,644	0	0.00000	1.00000	95.85
17.5	3,223,963	29,179	0.00905	0.99095	95.85
18.5	2,496,300	11,099	0.00445	0.99555	94.98
19.5	2,296,949	79,648	0.03468	0.96532	94.56
20.5	1,728,172	17,783	0.01029	0.98971	91.28
21.5	1,599,828	0	0.00000	1.00000	90.34
22.5	1,293,838	23,682	0.01830	0.98170	90.34
23.5	1,202,758	229,227	0.19058	0.80942	88.69
24.5	764,367	45,697	0.05978	0.94022	71.79
	Totals:	1,421,612			

BC Hydro Power Authority

Account 22001 - Plant, Concrete Or Steel

Placement Band - 1909 - 2019   Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 22001 - Plant, Concrete Or Steel

Placement Band - 1909 - 2019   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

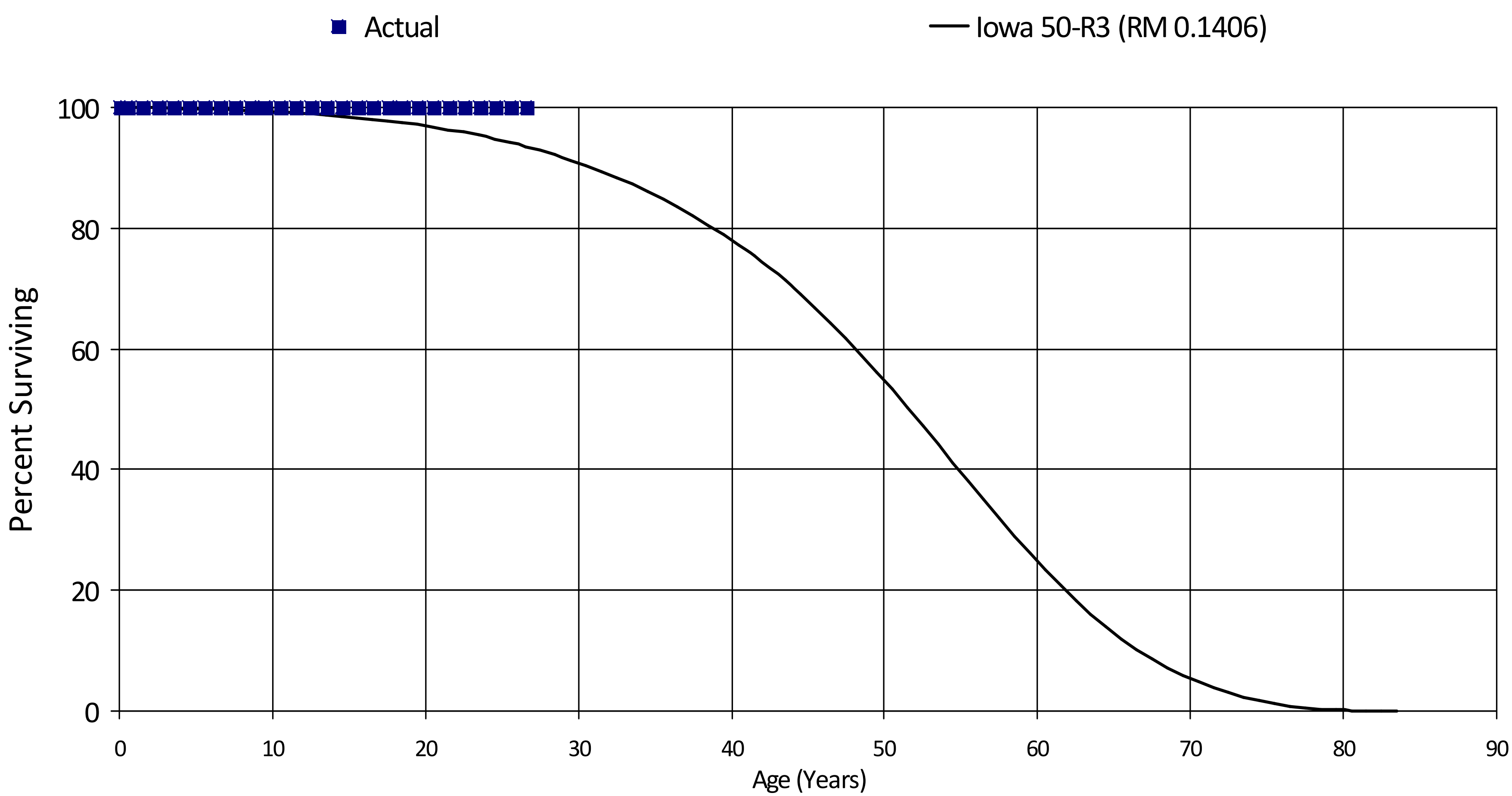
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	485,044,474	0	0.00000	1.00000	100.00
0.5	485,044,474	0	0.00000	1.00000	100.00
1.5	472,233,143	0	0.00000	1.00000	100.00
2.5	255,453,963	0	0.00000	1.00000	100.00
3.5	244,068,443	0	0.00000	1.00000	100.00
4.5	236,208,661	0	0.00000	1.00000	100.00
5.5	123,403,113	0	0.00000	1.00000	100.00
6.5	70,906,904	0	0.00000	1.00000	100.00
7.5	68,270,259	0	0.00000	1.00000	100.00
8.5	59,099,823	0	0.00000	1.00000	100.00
9.5	57,696,964	0	0.00000	1.00000	100.00
10.5	46,286,098	0	0.00000	1.00000	100.00
11.5	44,128,231	315,800	0.00716	0.99284	100.00
12.5	41,661,222	0	0.00000	1.00000	99.28
13.5	36,645,106	75,000	0.00205	0.99795	99.28
14.5	33,962,312	0	0.00000	1.00000	99.08
15.5	32,406,360	0	0.00000	1.00000	99.08
16.5	32,068,663	0	0.00000	1.00000	99.08
17.5	31,357,832	0	0.00000	1.00000	99.08
18.5	31,123,672	0	0.00000	1.00000	99.08
19.5	31,123,672	0	0.00000	1.00000	99.08
20.5	6,330,342	65,088	0.01028	0.98972	99.08
21.5	5,641,717	0	0.00000	1.00000	98.06
22.5	5,634,660	0	0.00000	1.00000	98.06
23.5	5,468,168	0	0.00000	1.00000	98.06
24.5	5,088,049	0	0.00000	1.00000	98.06
25.5	5,088,049	0	0.00000	1.00000	98.06
	Totals:	455,888			

BC Hydro Power Authority

Account 22002 - Commercial, Concrete Or Steel

Placement Band - 1978 - 2019   Experience Band - 2015 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 22002 - Commercial, Concrete Or Steel

Placement Band - 1978 - 2019   Experience Band - 2015 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	133,237,803	0	0.00000	1.00000	100.00
0.5	133,237,803	0	0.00000	1.00000	100.00
1.5	116,816,285	0	0.00000	1.00000	100.00
2.5	95,343,893	0	0.00000	1.00000	100.00
3.5	94,486,704	0	0.00000	1.00000	100.00
4.5	93,464,393	0	0.00000	1.00000	100.00
5.5	86,405,219	0	0.00000	1.00000	100.00
6.5	83,810,054	0	0.00000	1.00000	100.00
7.5	77,084,372	0	0.00000	1.00000	100.00
8.5	75,848,106	0	0.00000	1.00000	100.00
9.5	75,848,106	27,516	0.00036	0.99964	100.00
10.5	73,699,375	0	0.00000	1.00000	99.96
11.5	70,656,507	0	0.00000	1.00000	99.96
12.5	70,656,507	0	0.00000	1.00000	99.96
13.5	70,441,519	0	0.00000	1.00000	99.96
14.5	70,359,588	0	0.00000	1.00000	99.96
15.5	69,887,657	0	0.00000	1.00000	99.96
16.5	69,879,618	0	0.00000	1.00000	99.96
17.5	63,572,659	0	0.00000	1.00000	99.96
18.5	63,572,659	0	0.00000	1.00000	99.96
19.5	63,572,659	0	0.00000	1.00000	99.96
20.5	63,434,180	0	0.00000	1.00000	99.96
21.5	61,401,535	0	0.00000	1.00000	99.96
22.5	61,401,535	0	0.00000	1.00000	99.96
23.5	61,131,323	0	0.00000	1.00000	99.96
24.5	60,367,115	19,816	0.00033	0.99967	99.96
25.5	59,633,639	0	0.00000	1.00000	99.93
26.5	55,349,145	0	0.00000	1.00000	99.93

BC Hydro Power Authority

Account 22002 - Commercial, Concrete Or Steel

Placement Band - 1978 - 2019   Experience Band - 2015 - 2020

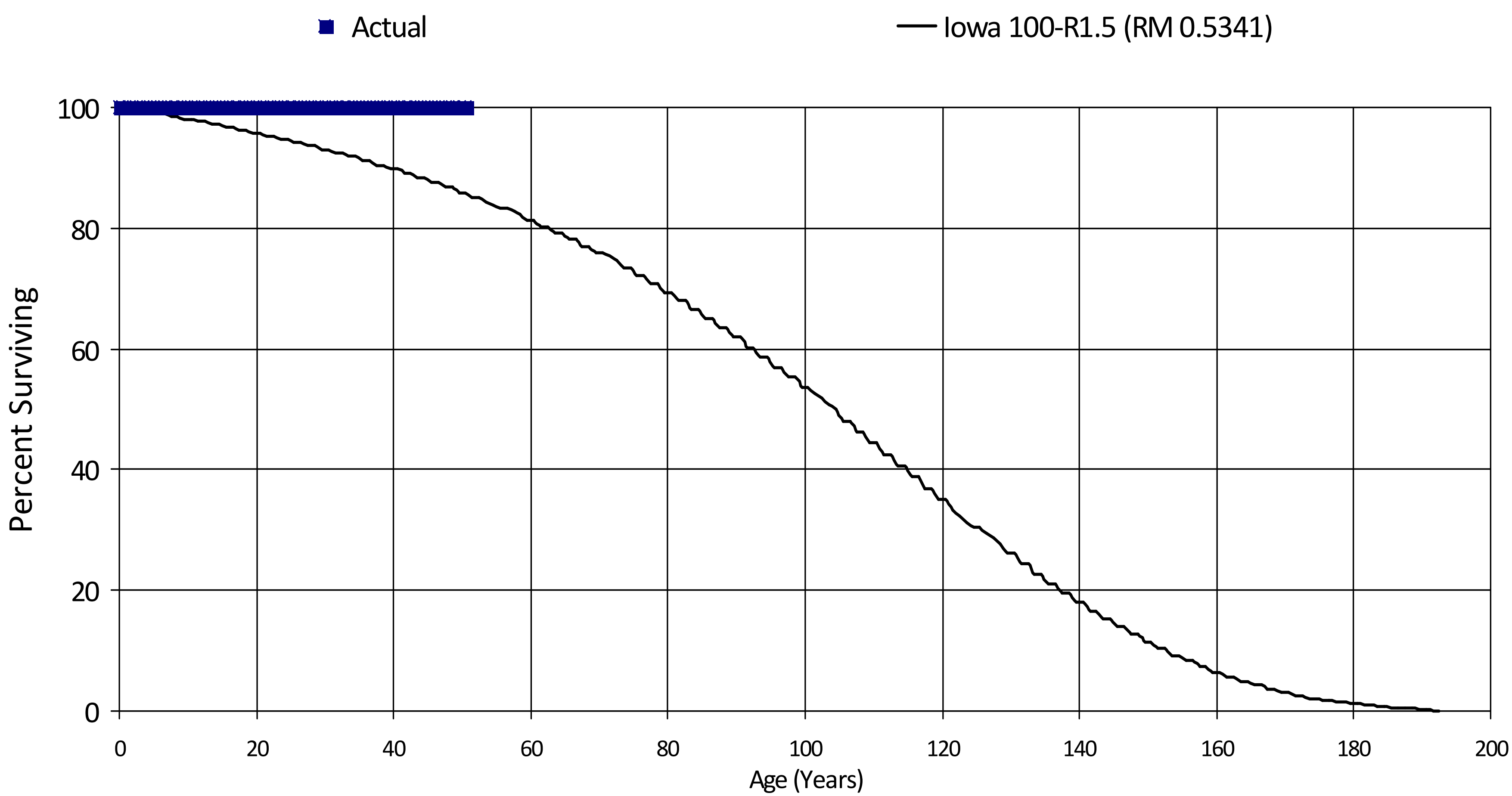
Totals:	47,332

BC Hydro Power Authority

Account 22003 - Powerhouse, Integral With Dam

Placement Band - 1949 - 2018 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 22003 - Powerhouse, Integral With Dam

Placement Band - 1949 - 2018   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	634,709,233	0	0.00000	1.00000	100.00
0.5	634,709,233	0	0.00000	1.00000	100.00
1.5	634,709,233	0	0.00000	1.00000	100.00
2.5	632,111,125	0	0.00000	1.00000	100.00
3.5	630,437,966	0	0.00000	1.00000	100.00
4.5	625,671,100	0	0.00000	1.00000	100.00
5.5	625,671,100	0	0.00000	1.00000	100.00
6.5	562,498,598	0	0.00000	1.00000	100.00
7.5	562,498,598	0	0.00000	1.00000	100.00
8.5	561,719,870	0	0.00000	1.00000	100.00
9.5	561,719,870	0	0.00000	1.00000	100.00
10.5	492,405,553	0	0.00000	1.00000	100.00
11.5	491,924,313	0	0.00000	1.00000	100.00
12.5	491,924,313	0	0.00000	1.00000	100.00
13.5	491,924,313	0	0.00000	1.00000	100.00
14.5	491,739,367	0	0.00000	1.00000	100.00
15.5	491,662,671	0	0.00000	1.00000	100.00
16.5	491,662,671	0	0.00000	1.00000	100.00
17.5	491,662,671	0	0.00000	1.00000	100.00
18.5	491,625,445	0	0.00000	1.00000	100.00
19.5	491,605,713	0	0.00000	1.00000	100.00
20.5	491,558,803	0	0.00000	1.00000	100.00
21.5	491,515,781	0	0.00000	1.00000	100.00
22.5	491,515,781	0	0.00000	1.00000	100.00
23.5	491,515,781	0	0.00000	1.00000	100.00
24.5	491,165,871	0	0.00000	1.00000	100.00
25.5	490,780,557	0	0.00000	1.00000	100.00
26.5	490,780,557	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 22003 - Powerhouse, Integral With Dam

Placement Band - 1949 - 2018 Experience Band - 2013 - 2020

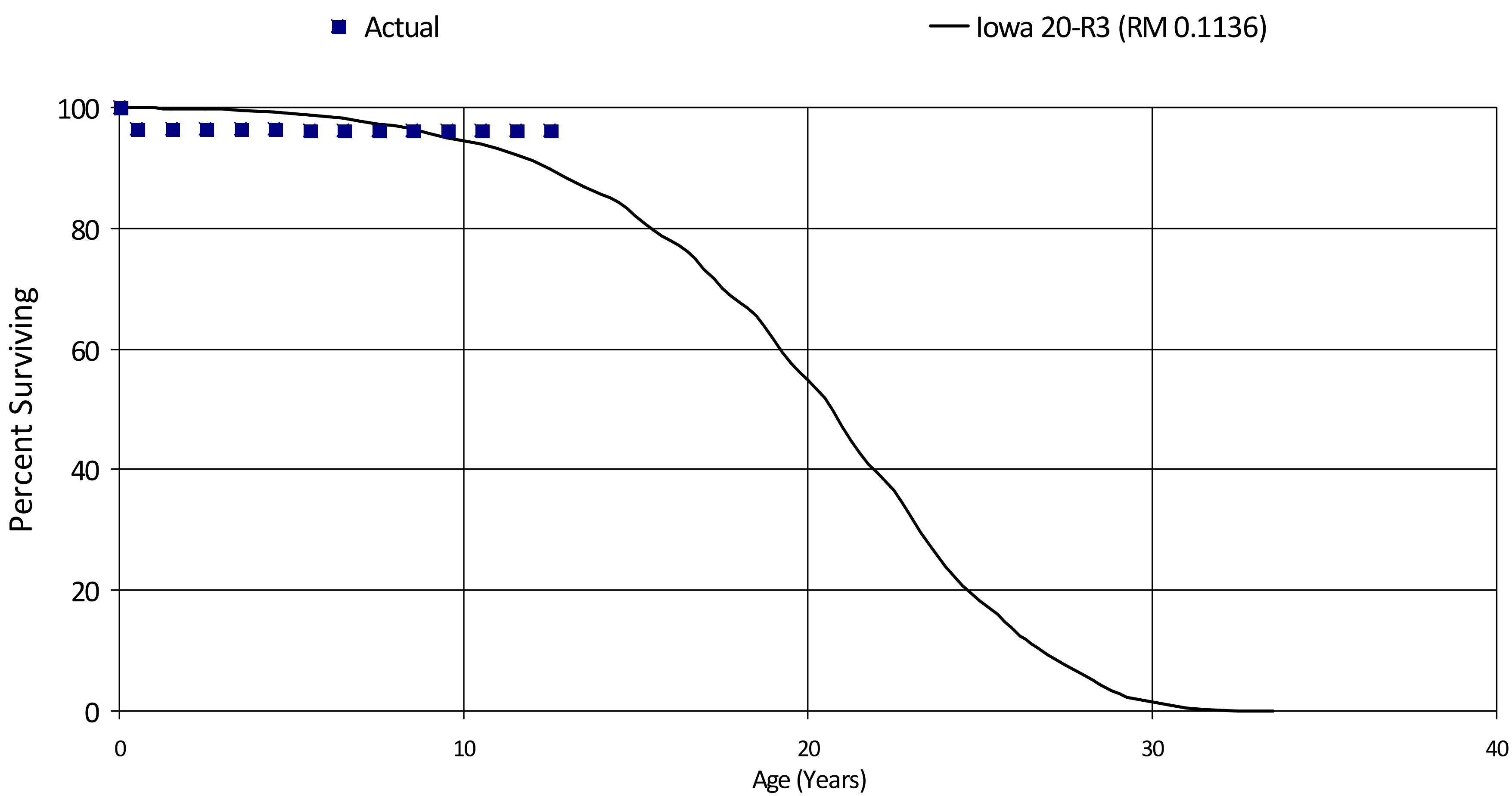
27.5	490,668,152	0	0.00000	1.00000	100.00
28.5	490,668,152	0	0.00000	1.00000	100.00
29.5	490,668,152	0	0.00000	1.00000	100.00
30.5	490,668,152	0	0.00000	1.00000	100.00
31.5	490,668,152	0	0.00000	1.00000	100.00
32.5	490,668,152	0	0.00000	1.00000	100.00
33.5	490,668,152	0	0.00000	1.00000	100.00
34.5	479,603,911	0	0.00000	1.00000	100.00
35.5	250,592,205	0	0.00000	1.00000	100.00
36.5	250,592,205	0	0.00000	1.00000	100.00
37.5	250,592,205	0	0.00000	1.00000	100.00
38.5	250,592,205	0	0.00000	1.00000	100.00
39.5	187,547,050	0	0.00000	1.00000	100.00
40.5	151,590,998	0	0.00000	1.00000	100.00
41.5	151,590,998	0	0.00000	1.00000	100.00
42.5	151,590,998	0	0.00000	1.00000	100.00
43.5	138,239,108	0	0.00000	1.00000	100.00
44.5	138,239,108	0	0.00000	1.00000	100.00
45.5	138,239,108	0	0.00000	1.00000	100.00
46.5	127,309,687	0	0.00000	1.00000	100.00
47.5	62,270,298	0	0.00000	1.00000	100.00
48.5	60,066,146	0	0.00000	1.00000	100.00
49.5	60,066,146	0	0.00000	1.00000	100.00
50.5	60,066,146	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 22004 - Building, Wood

Placement Band - 1993 - 2020 Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 22004 - Building, Wood

Placement Band - 1993 - 2020   Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

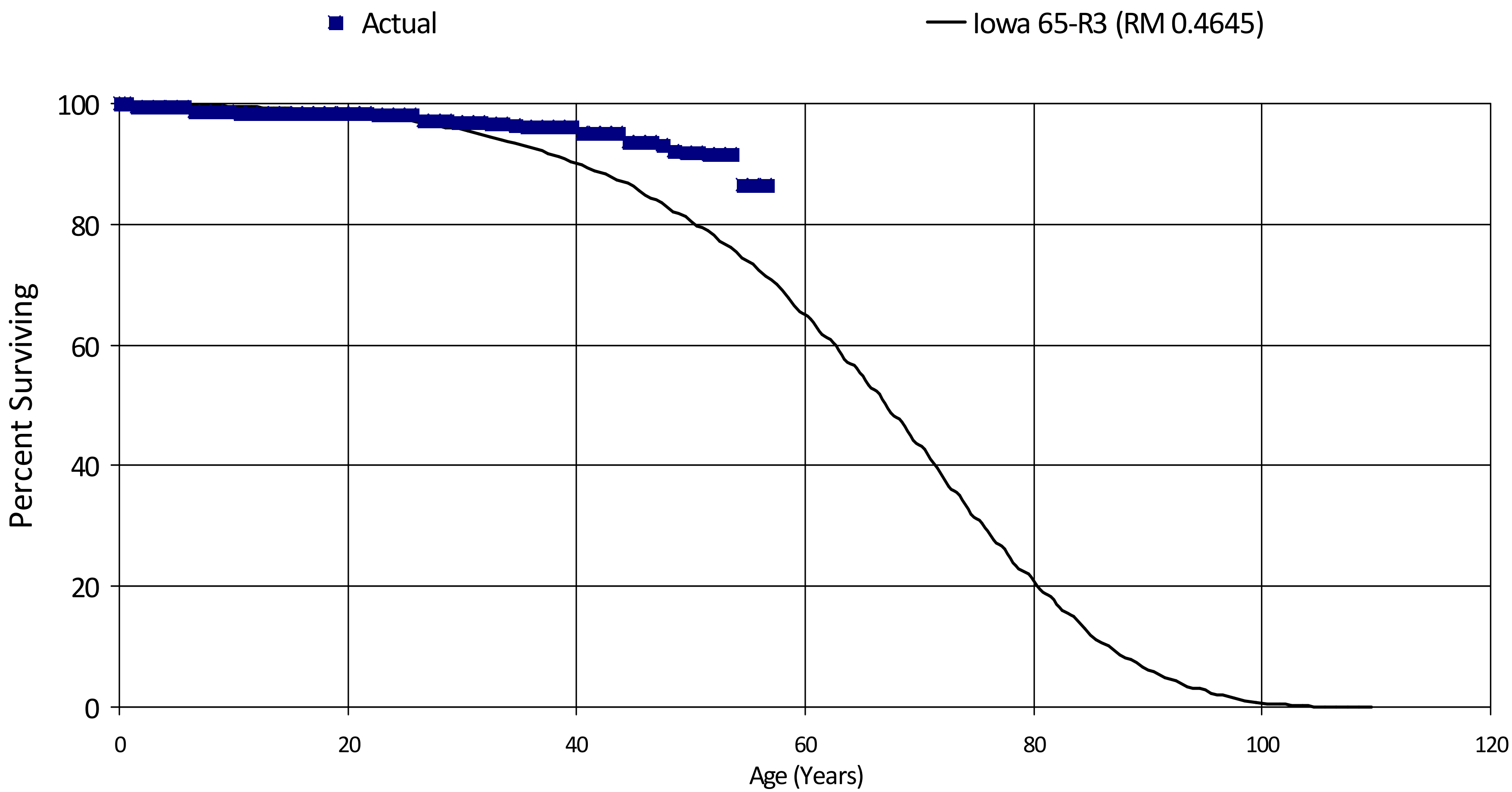
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	16,191,134	596,443	0.03684	0.96316	100.00
0.5	15,250,150	0	0.00000	1.00000	96.32
1.5	15,175,451	0	0.00000	1.00000	96.32
2.5	13,845,550	0	0.00000	1.00000	96.32
3.5	13,845,550	0	0.00000	1.00000	96.32
4.5	13,812,170	23,892	0.00173	0.99827	96.32
5.5	13,693,913	0	0.00000	1.00000	96.15
6.5	13,693,913	0	0.00000	1.00000	96.15
7.5	13,621,676	0	0.00000	1.00000	96.15
8.5	13,568,408	0	0.00000	1.00000	96.15
9.5	2,667,486	0	0.00000	1.00000	96.15
10.5	2,667,486	0	0.00000	1.00000	96.15
11.5	400,915	0	0.00000	1.00000	96.15
12.5	324,154	0	0.00000	1.00000	96.15
	Totals:	620,335			

BC Hydro Power Authority

Account 22005 - Building, Composite Pool

Placement Band - 1902 - 2020 Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 22005 - Building, Composite Pool

Placement Band - 1902 - 2020 Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	595,507,355	0	0.00000	1.00000	100.00
0.5	591,234,346	2,335,635	0.00395	0.99605	100.00
1.5	571,812,792	0	0.00000	1.00000	99.60
2.5	537,926,857	0	0.00000	1.00000	99.60
3.5	505,686,332	0	0.00000	1.00000	99.60
4.5	485,368,212	23,892	0.00005	0.99995	99.60
5.5	402,032,981	3,977,982	0.00989	0.99011	99.60
6.5	370,467,054	0	0.00000	1.00000	98.61
7.5	353,280,172	0	0.00000	1.00000	98.61
8.5	338,450,033	0	0.00000	1.00000	98.61
9.5	297,610,703	19,789	0.00007	0.99993	98.61
10.5	238,021,553	62,155	0.00026	0.99974	98.60
11.5	234,260,106	0	0.00000	1.00000	98.57
12.5	153,654,229	0	0.00000	1.00000	98.57
13.5	151,811,953	98,383	0.00065	0.99935	98.57
14.5	149,725,606	7,148	0.00005	0.99995	98.51
15.5	148,422,583	0	0.00000	1.00000	98.51
16.5	147,024,986	0	0.00000	1.00000	98.51
17.5	143,652,724	59,575	0.00041	0.99959	98.51
18.5	141,773,853	0	0.00000	1.00000	98.47
19.5	141,163,091	0	0.00000	1.00000	98.47
20.5	140,013,248	0	0.00000	1.00000	98.47
21.5	137,717,766	390,539	0.00284	0.99716	98.47
22.5	136,867,578	54,773	0.00040	0.99960	98.19
23.5	134,502,523	0	0.00000	1.00000	98.15
24.5	134,040,399	50,257	0.00037	0.99963	98.15
25.5	133,707,108	1,353,756	0.01012	0.98988	98.11
26.5	132,191,269	0	0.00000	1.00000	97.12

BC Hydro Power Authority

Account 22005 - Building, Composite Pool

Placement Band - 1902 - 2020 Experience Band - 2011 - 2020

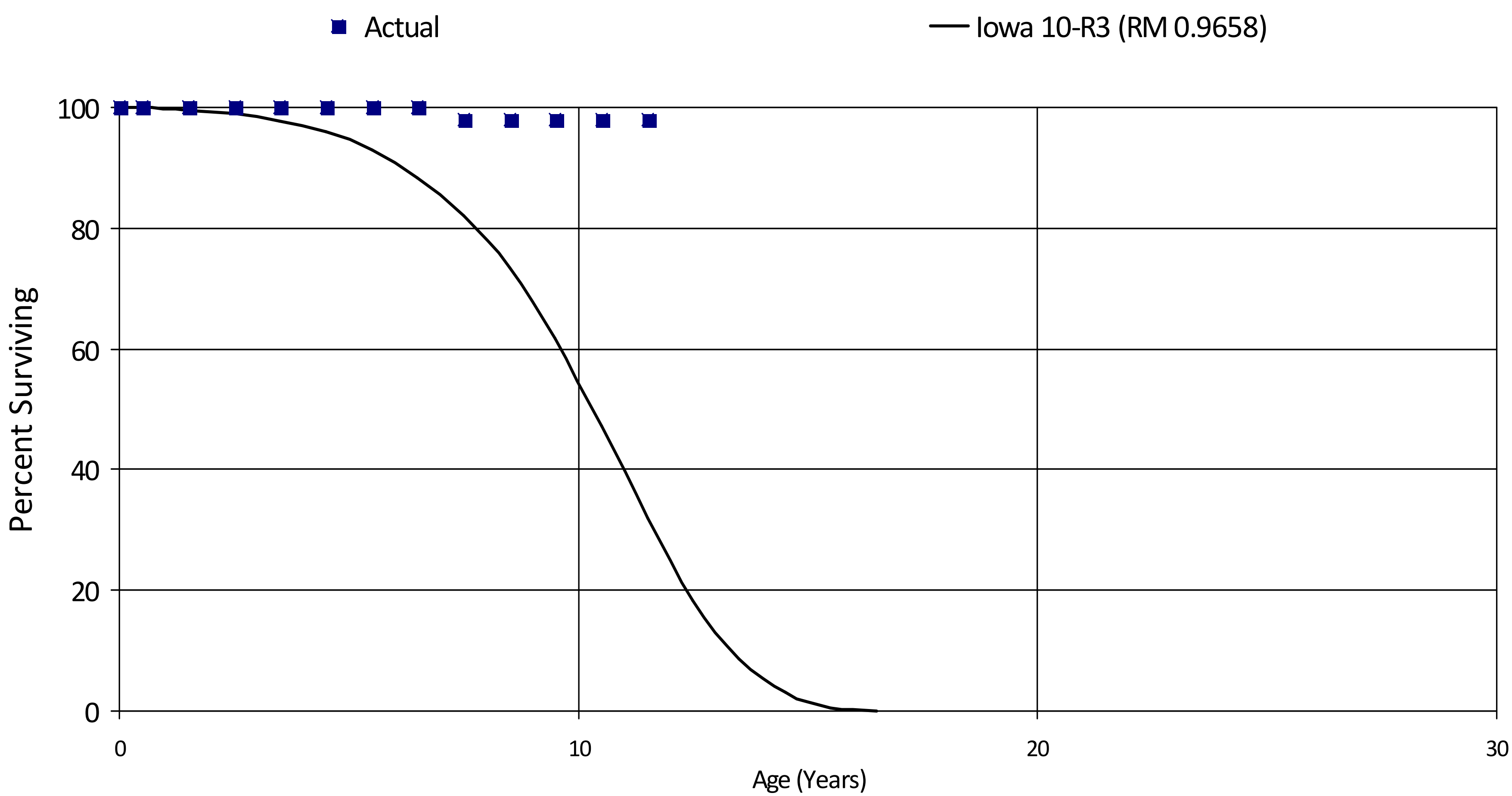
27.5	131,403,626	0	0.00000	1.00000	97.12
28.5	128,031,760	147,518	0.00115	0.99885	97.12
29.5	125,347,995	0	0.00000	1.00000	97.01
30.5	123,467,655	0	0.00000	1.00000	97.01
31.5	122,551,421	282,531	0.00231	0.99769	97.01
32.5	112,963,584	0	0.00000	1.00000	96.79
33.5	110,960,846	392,636	0.00354	0.99646	96.79
34.5	109,649,279	336,323	0.00307	0.99693	96.45
35.5	75,662,856	0	0.00000	1.00000	96.15
36.5	73,706,415	17,000	0.00023	0.99977	96.15
37.5	72,243,270	0	0.00000	1.00000	96.13
38.5	70,056,866	13,730	0.00020	0.99980	96.13
39.5	61,354,260	545,446	0.00889	0.99111	96.11
40.5	56,719,390	0	0.00000	1.00000	95.26
41.5	54,000,355	24,833	0.00046	0.99954	95.26
42.5	41,851,919	0	0.00000	1.00000	95.22
43.5	37,366,390	656,734	0.01758	0.98242	95.22
44.5	35,239,429	0	0.00000	1.00000	93.55
45.5	34,871,195	0	0.00000	1.00000	93.55
46.5	29,739,332	94,498	0.00318	0.99682	93.55
47.5	28,832,226	325,560	0.01129	0.98871	93.25
48.5	27,763,169	78,260	0.00282	0.99718	92.20
49.5	26,145,071	20,577	0.00079	0.99921	91.94
50.5	25,448,512	32,049	0.00126	0.99874	91.87
51.5	23,388,088	42,929	0.00184	0.99816	91.75
52.5	20,718,546	0	0.00000	1.00000	91.58
53.5	20,398,307	1,106,887	0.05426	0.94574	91.58
54.5	18,401,542	0	0.00000	1.00000	86.61
55.5	18,353,820	0	0.00000	1.00000	86.61
56.5	18,136,082	0	0.00000	1.00000	86.61
	Totals:	12,551,395			

BC Hydro Power Authority

Account 22006 - Equipment Shelter

Placement Band - 1993 - 2020   Experience Band - 2018 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 22006 - Equipment Shelter

Placement Band - 1993 - 2020   Experience Band - 2018 - 2020

RETIREMENT RATE ANALYSIS

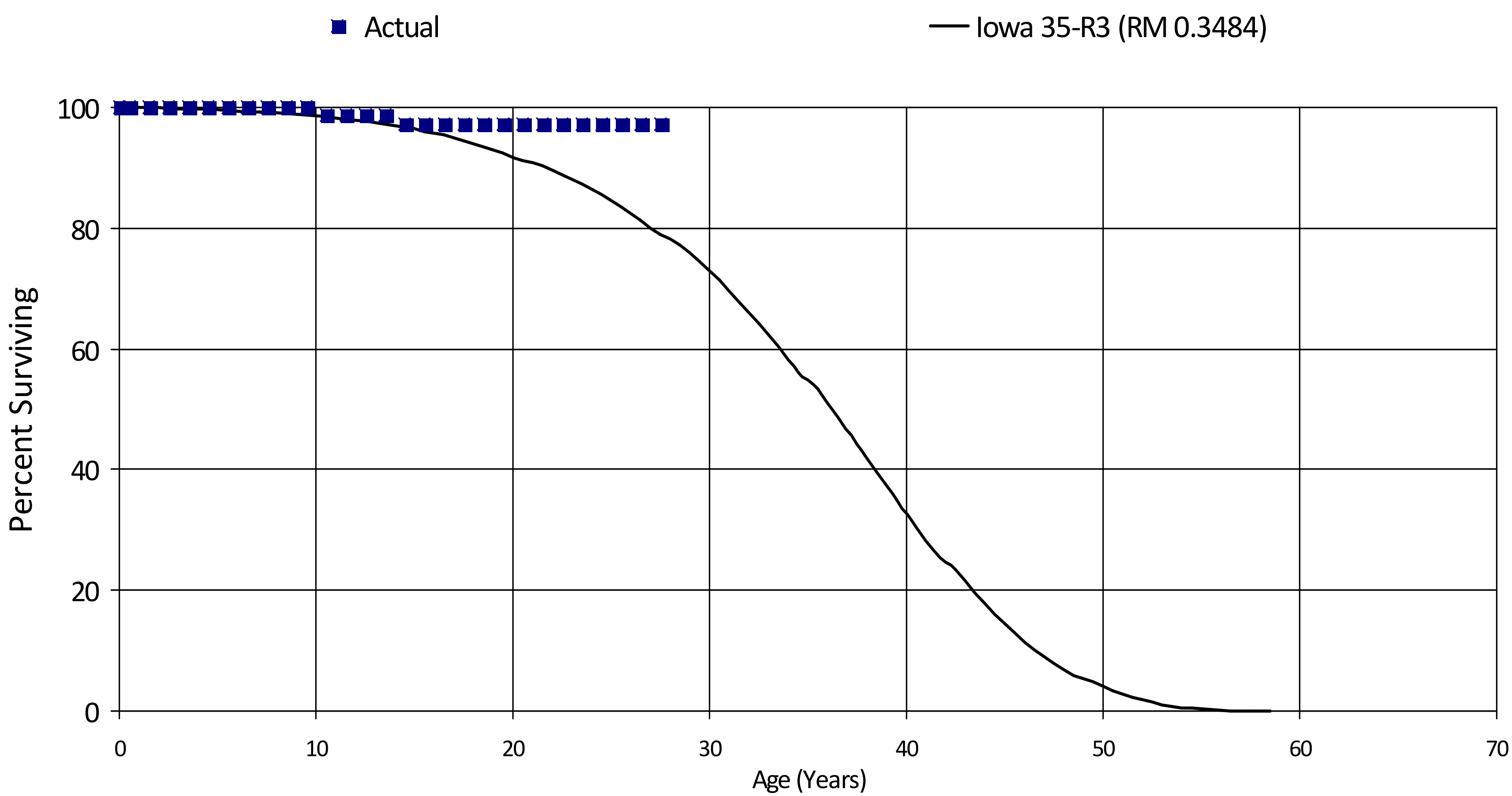
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	14,983,121	0	0.00000	1.00000	100.00
0.5	14,864,109	0	0.00000	1.00000	100.00
1.5	14,484,542	0	0.00000	1.00000	100.00
2.5	13,788,613	0	0.00000	1.00000	100.00
3.5	11,103,702	0	0.00000	1.00000	100.00
4.5	8,489,738	0	0.00000	1.00000	100.00
5.5	5,339,420	0	0.00000	1.00000	100.00
6.5	3,413,112	68,040	0.01993	0.98007	100.00
7.5	3,292,146	0	0.00000	1.00000	98.01
8.5	3,292,146	0	0.00000	1.00000	98.01
9.5	1,036,976	0	0.00000	1.00000	98.01
10.5	926,914	0	0.00000	1.00000	98.01
11.5	588,501	0	0.00000	1.00000	98.01
	Totals:	68,040			

BC Hydro Power Authority

Account 22007 - Buildings - Envelope

Placement Band - 1982 - 2020   Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 22007 - Buildings - Envelope

Placement Band - 1982 - 2020   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	171,556,214	0	0.00000	1.00000	100.00
0.5	170,705,902	0	0.00000	1.00000	100.00
1.5	146,574,985	0	0.00000	1.00000	100.00
2.5	135,471,782	0	0.00000	1.00000	100.00
3.5	107,119,457	0	0.00000	1.00000	100.00
4.5	85,987,012	0	0.00000	1.00000	100.00
5.5	57,218,043	0	0.00000	1.00000	100.00
6.5	47,701,320	0	0.00000	1.00000	100.00
7.5	44,375,680	0	0.00000	1.00000	100.00
8.5	24,216,053	3,672	0.00015	0.99985	100.00
9.5	19,250,743	263,462	0.01369	0.98631	99.98
10.5	17,222,744	0	0.00000	1.00000	98.61
11.5	15,998,273	0	0.00000	1.00000	98.61
12.5	14,422,043	0	0.00000	1.00000	98.61
13.5	14,031,048	182,426	0.01300	0.98700	98.61
14.5	13,669,287	0	0.00000	1.00000	97.33
15.5	13,570,829	0	0.00000	1.00000	97.33
16.5	13,413,702	2,186	0.00016	0.99984	97.33
17.5	13,216,654	0	0.00000	1.00000	97.31
18.5	13,043,937	9,734	0.00075	0.99925	97.31
19.5	12,878,258	0	0.00000	1.00000	97.24
20.5	12,811,162	8,902	0.00069	0.99931	97.24
21.5	12,755,334	0	0.00000	1.00000	97.17
22.5	12,751,803	1	0.00000	1.00000	97.17
23.5	12,513,988	0	0.00000	1.00000	97.17
24.5	12,151,420	3,999	0.00033	0.99967	97.17
25.5	12,128,314	0	0.00000	1.00000	97.14
26.5	11,405,958	0	0.00000	1.00000	97.14

BC Hydro Power Authority

Account 22007 - Buildings - Envelope

Placement Band - 1982 - 2020 Experience Band - 2011 - 2020

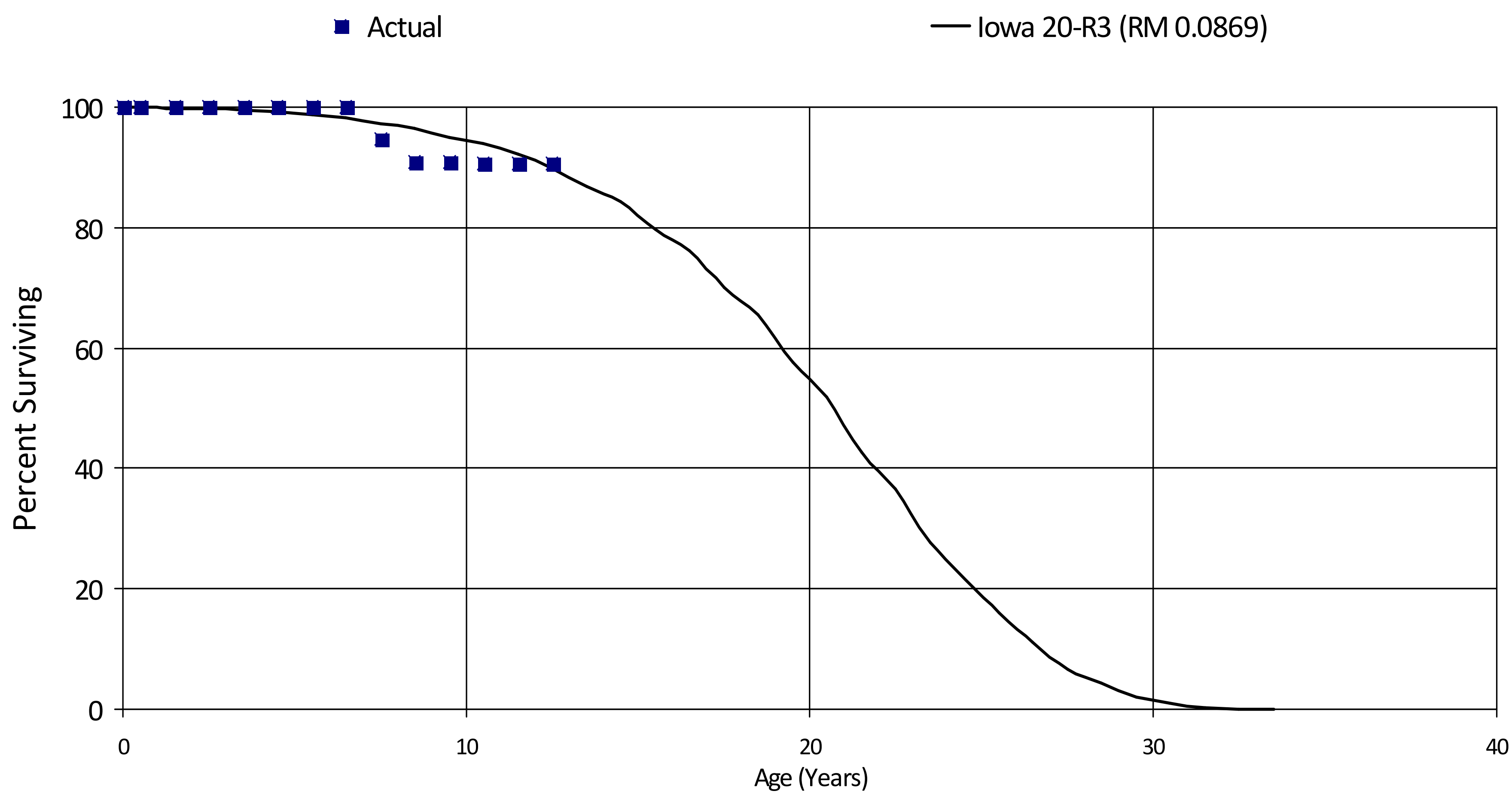
27.5	7,135,395	2,180	0.00031	0.99969	97.14
	Totals:	476,562			

BC Hydro Power Authority

Account 22009 - Buildings - HVAC Systems & Components

Placement Band - 1996 - 2020   Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 22009 - Buildings - HVAC Systems & Components

Placement Band - 1996 - 2020   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

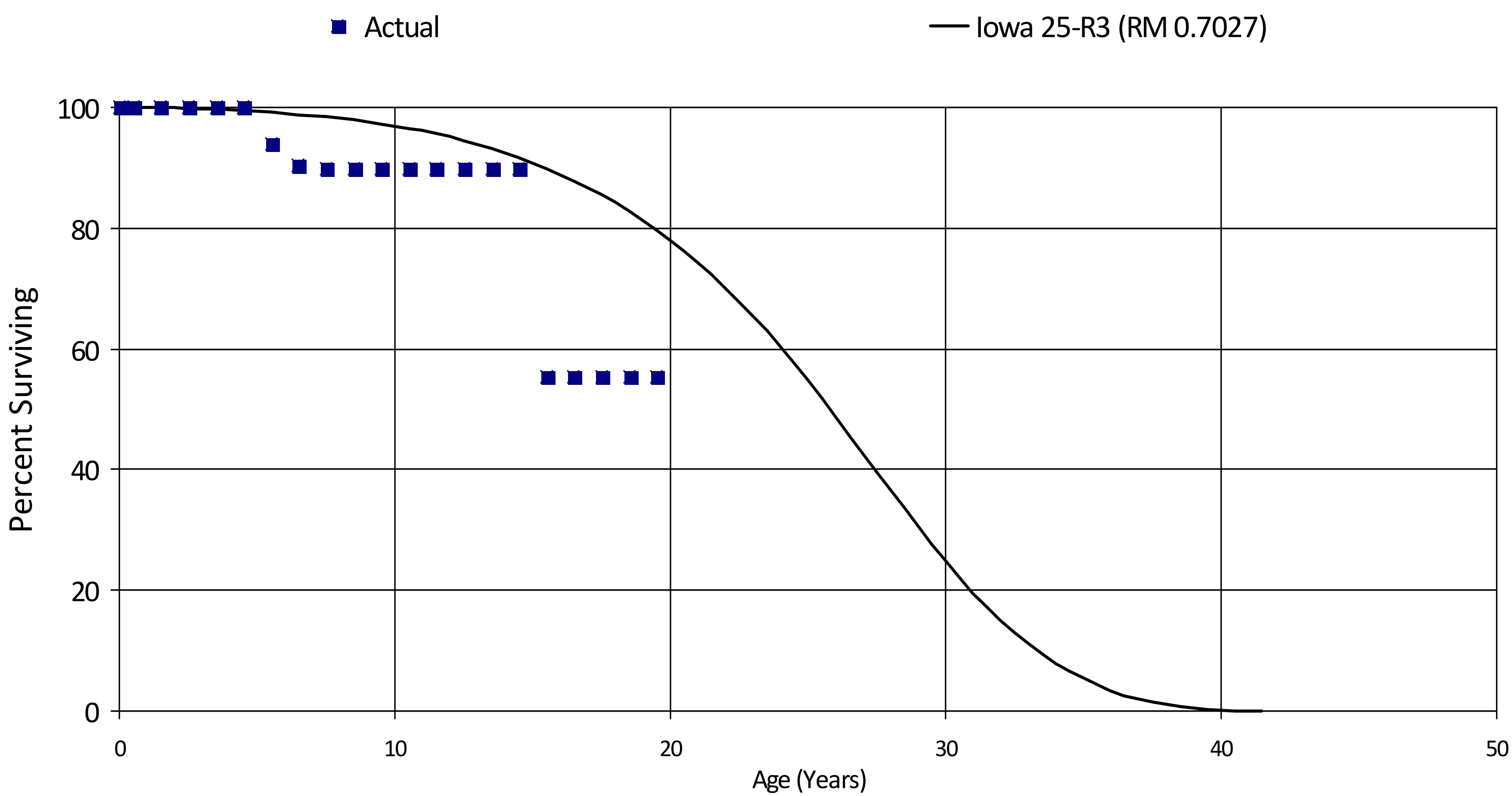
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	105,599,565	0	0.00000	1.00000	100.00
0.5	97,503,182	0	0.00000	1.00000	100.00
1.5	78,455,704	0	0.00000	1.00000	100.00
2.5	62,894,634	0	0.00000	1.00000	100.00
3.5	46,151,224	0	0.00000	1.00000	100.00
4.5	36,852,615	0	0.00000	1.00000	100.00
5.5	24,116,549	4,881	0.00020	0.99980	100.00
6.5	18,602,684	998,331	0.05367	0.94633	99.98
7.5	13,778,503	544,950	0.03955	0.96045	94.61
8.5	11,935,720	8,811	0.00074	0.99926	90.87
9.5	6,824,420	9,037	0.00132	0.99868	90.80
10.5	6,292,286	1,488	0.00024	0.99976	90.68
11.5	5,870,951	0	0.00000	1.00000	90.66
12.5	1,273,218	877	0.00069	0.99931	90.66
	Totals:	1,568,375			

BC Hydro Power Authority

Account 22101 - Office Trailer / Mobile Home

Placement Band - 1969 - 2020   Experience Band - 2015 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 22101 - Office Trailer / Mobile Home

Placement Band - 1969 - 2020 Experience Band - 2015 - 2020

RETIREMENT RATE ANALYSIS

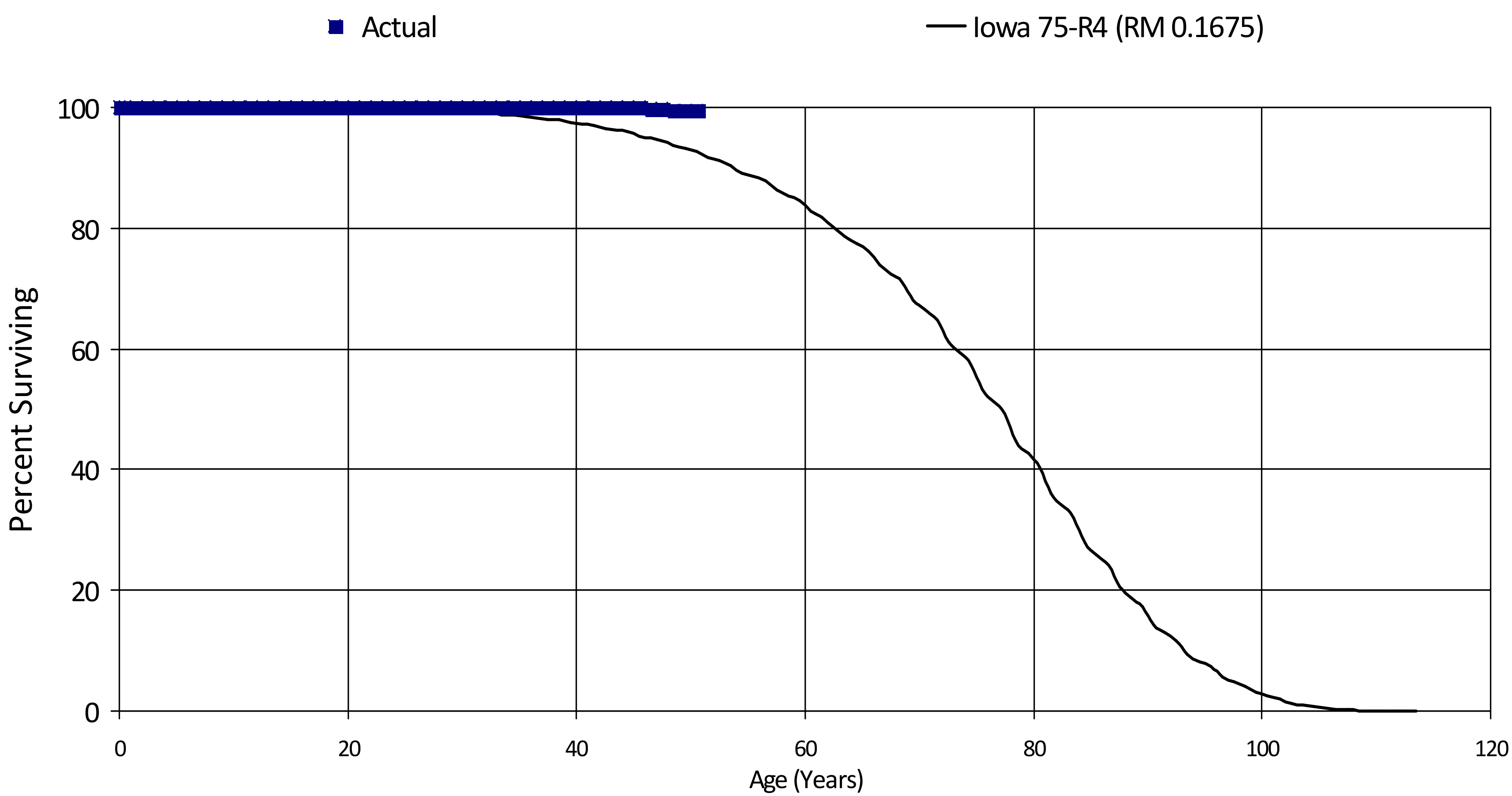
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	15,258,790	0	0.00000	1.00000	100.00
0.5	15,240,185	0	0.00000	1.00000	100.00
1.5	14,631,763	0	0.00000	1.00000	100.00
2.5	12,742,178	0	0.00000	1.00000	100.00
3.5	12,486,672	0	0.00000	1.00000	100.00
4.5	12,032,202	723,651	0.06014	0.93986	100.00
5.5	11,292,485	442,260	0.03916	0.96084	93.99
6.5	10,850,225	49,654	0.00458	0.99542	90.31
7.5	10,424,338	0	0.00000	1.00000	89.90
8.5	4,234,665	0	0.00000	1.00000	89.90
9.5	4,209,769	0	0.00000	1.00000	89.90
10.5	4,209,769	0	0.00000	1.00000	89.90
11.5	2,489,716	0	0.00000	1.00000	89.90
12.5	2,211,350	0	0.00000	1.00000	89.90
13.5	2,088,726	0	0.00000	1.00000	89.90
14.5	2,088,726	805,265	0.38553	0.61447	89.90
15.5	857,897	0	0.00000	1.00000	55.24
16.5	738,146	0	0.00000	1.00000	55.24
17.5	554,876	0	0.00000	1.00000	55.24
18.5	483,737	0	0.00000	1.00000	55.24
19.5	483,737	0	0.00000	1.00000	55.24
	Totals:	2,020,830			

BC Hydro Power Authority

Account 23001 - Spillway, Separate From Dam

Placement Band - 1958 - 2018   Experience Band - 2015 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23001 - Spillway, Separate From Dam

Placement Band - 1958 - 2018   Experience Band - 2015 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	312,334,642	0	0.00000	1.00000	100.00
0.5	312,334,642	0	0.00000	1.00000	100.00
1.5	312,334,642	0	0.00000	1.00000	100.00
2.5	290,439,689	0	0.00000	1.00000	100.00
3.5	245,207,441	0	0.00000	1.00000	100.00
4.5	231,802,412	0	0.00000	1.00000	100.00
5.5	181,039,185	0	0.00000	1.00000	100.00
6.5	172,882,743	0	0.00000	1.00000	100.00
7.5	172,882,743	0	0.00000	1.00000	100.00
8.5	147,847,896	0	0.00000	1.00000	100.00
9.5	147,847,896	0	0.00000	1.00000	100.00
10.5	110,852,874	0	0.00000	1.00000	100.00
11.5	110,852,874	0	0.00000	1.00000	100.00
12.5	110,852,874	0	0.00000	1.00000	100.00
13.5	110,852,874	0	0.00000	1.00000	100.00
14.5	110,133,591	0	0.00000	1.00000	100.00
15.5	91,526,686	0	0.00000	1.00000	100.00
16.5	91,459,170	0	0.00000	1.00000	100.00
17.5	91,459,170	0	0.00000	1.00000	100.00
18.5	91,459,170	0	0.00000	1.00000	100.00
19.5	91,459,170	0	0.00000	1.00000	100.00
20.5	91,459,170	0	0.00000	1.00000	100.00
21.5	91,459,170	0	0.00000	1.00000	100.00
22.5	91,459,170	0	0.00000	1.00000	100.00
23.5	91,459,170	0	0.00000	1.00000	100.00
24.5	91,459,170	0	0.00000	1.00000	100.00
25.5	91,459,170	0	0.00000	1.00000	100.00
26.5	86,933,378	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 23001 - Spillway, Separate From Dam

Placement Band - 1958 - 2018 Experience Band - 2015 - 2020

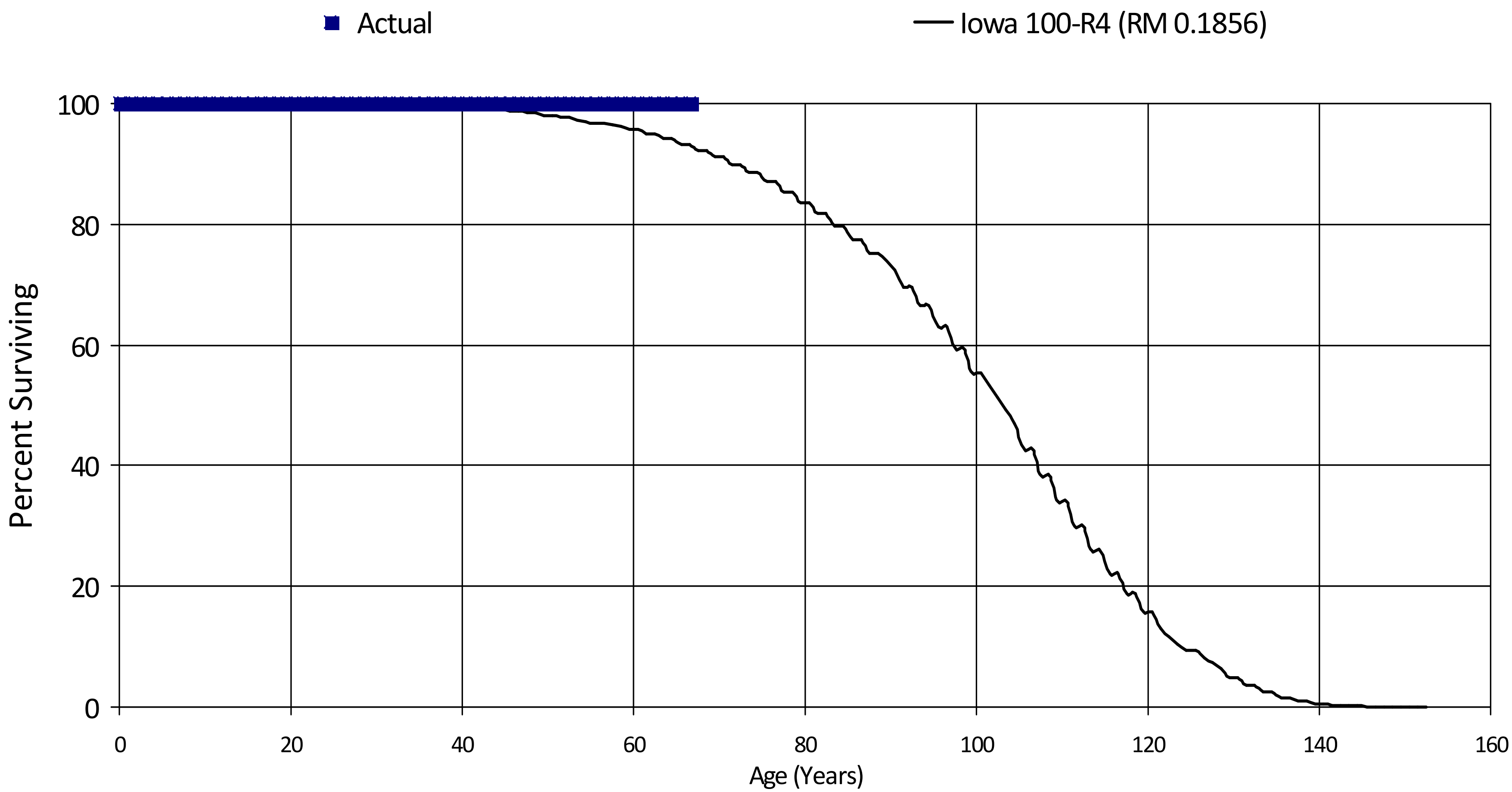
27.5	74,245,839	0	0.00000	1.00000	100.00
28.5	74,245,839	0	0.00000	1.00000	100.00
29.5	74,245,839	0	0.00000	1.00000	100.00
30.5	74,245,839	0	0.00000	1.00000	100.00
31.5	74,245,839	0	0.00000	1.00000	100.00
32.5	74,244,311	0	0.00000	1.00000	100.00
33.5	73,898,450	0	0.00000	1.00000	100.00
34.5	73,898,450	0	0.00000	1.00000	100.00
35.5	39,259,445	0	0.00000	1.00000	100.00
36.5	39,259,445	0	0.00000	1.00000	100.00
37.5	39,259,445	0	0.00000	1.00000	100.00
38.5	39,259,445	0	0.00000	1.00000	100.00
39.5	17,834,103	0	0.00000	1.00000	100.00
40.5	17,834,103	0	0.00000	1.00000	100.00
41.5	17,834,103	0	0.00000	1.00000	100.00
42.5	17,834,103	0	0.00000	1.00000	100.00
43.5	17,834,103	0	0.00000	1.00000	100.00
44.5	17,834,103	0	0.00000	1.00000	100.00
45.5	17,834,103	40,702	0.00228	0.99772	100.00
46.5	17,793,401	0	0.00000	1.00000	99.77
47.5	17,793,401	56,353	0.00317	0.99683	99.77
48.5	17,737,048	0	0.00000	1.00000	99.45
49.5	17,737,048	0	0.00000	1.00000	99.45
50.5	17,482,852	0	0.00000	1.00000	99.45
	Totals:	97,055			

BC Hydro Power Authority

Account 23101 - Intake Structure, Power

Placement Band - 1931 - 2018 Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23101 - Intake Structure, Power

Placement Band - 1931 - 2018   Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	235,630,130	0	0.00000	1.00000	100.00
0.5	235,630,130	0	0.00000	1.00000	100.00
1.5	235,630,130	0	0.00000	1.00000	100.00
2.5	132,786,802	0	0.00000	1.00000	100.00
3.5	118,504,998	0	0.00000	1.00000	100.00
4.5	103,090,680	0	0.00000	1.00000	100.00
5.5	102,650,970	0	0.00000	1.00000	100.00
6.5	101,454,509	0	0.00000	1.00000	100.00
7.5	101,454,509	0	0.00000	1.00000	100.00
8.5	101,454,509	0	0.00000	1.00000	100.00
9.5	101,454,509	0	0.00000	1.00000	100.00
10.5	65,008,038	0	0.00000	1.00000	100.00
11.5	64,983,983	0	0.00000	1.00000	100.00
12.5	62,465,816	0	0.00000	1.00000	100.00
13.5	62,395,545	0	0.00000	1.00000	100.00
14.5	62,123,010	0	0.00000	1.00000	100.00
15.5	62,123,010	0	0.00000	1.00000	100.00
16.5	61,995,682	0	0.00000	1.00000	100.00
17.5	61,995,682	0	0.00000	1.00000	100.00
18.5	61,995,682	0	0.00000	1.00000	100.00
19.5	61,995,682	0	0.00000	1.00000	100.00
20.5	55,207,762	0	0.00000	1.00000	100.00
21.5	55,207,762	0	0.00000	1.00000	100.00
22.5	55,207,762	0	0.00000	1.00000	100.00
23.5	55,207,762	0	0.00000	1.00000	100.00
24.5	55,207,762	0	0.00000	1.00000	100.00
25.5	55,207,762	0	0.00000	1.00000	100.00
26.5	55,207,762	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 23101 - Intake Structure, Power

Placement Band - 1931 - 2018 Experience Band - 2016 - 2020

27.5	55,207,762	0	0.00000	1.00000	100.00
28.5	55,207,762	0	0.00000	1.00000	100.00
29.5	55,207,762	0	0.00000	1.00000	100.00
30.5	55,207,762	0	0.00000	1.00000	100.00
31.5	55,207,762	0	0.00000	1.00000	100.00
32.5	55,207,762	0	0.00000	1.00000	100.00
33.5	55,168,375	0	0.00000	1.00000	100.00
34.5	55,168,375	0	0.00000	1.00000	100.00
35.5	55,168,375	0	0.00000	1.00000	100.00
36.5	55,168,375	0	0.00000	1.00000	100.00
37.5	55,168,375	0	0.00000	1.00000	100.00
38.5	55,168,375	0	0.00000	1.00000	100.00
39.5	36,414,358	0	0.00000	1.00000	100.00
40.5	36,414,358	0	0.00000	1.00000	100.00
41.5	36,414,358	0	0.00000	1.00000	100.00
42.5	36,414,358	0	0.00000	1.00000	100.00
43.5	25,285,934	0	0.00000	1.00000	100.00
44.5	25,285,934	0	0.00000	1.00000	100.00
45.5	25,285,934	0	0.00000	1.00000	100.00
46.5	25,285,934	0	0.00000	1.00000	100.00
47.5	24,622,503	0	0.00000	1.00000	100.00
48.5	24,622,503	13,500	0.00055	0.99945	100.00
49.5	24,609,003	0	0.00000	1.00000	99.94
50.5	24,436,347	0	0.00000	1.00000	99.94
51.5	18,374,337	0	0.00000	1.00000	99.94
52.5	17,968,354	0	0.00000	1.00000	99.94
53.5	13,662,718	0	0.00000	1.00000	99.94
54.5	13,662,718	0	0.00000	1.00000	99.94
55.5	13,662,718	0	0.00000	1.00000	99.94
56.5	11,054,975	0	0.00000	1.00000	99.94
57.5	10,907,568	0	0.00000	1.00000	99.94

BC Hydro Power Authority

Account 23101 - Intake Structure, Power

Placement Band - 1931 - 2018 Experience Band - 2016 - 2020

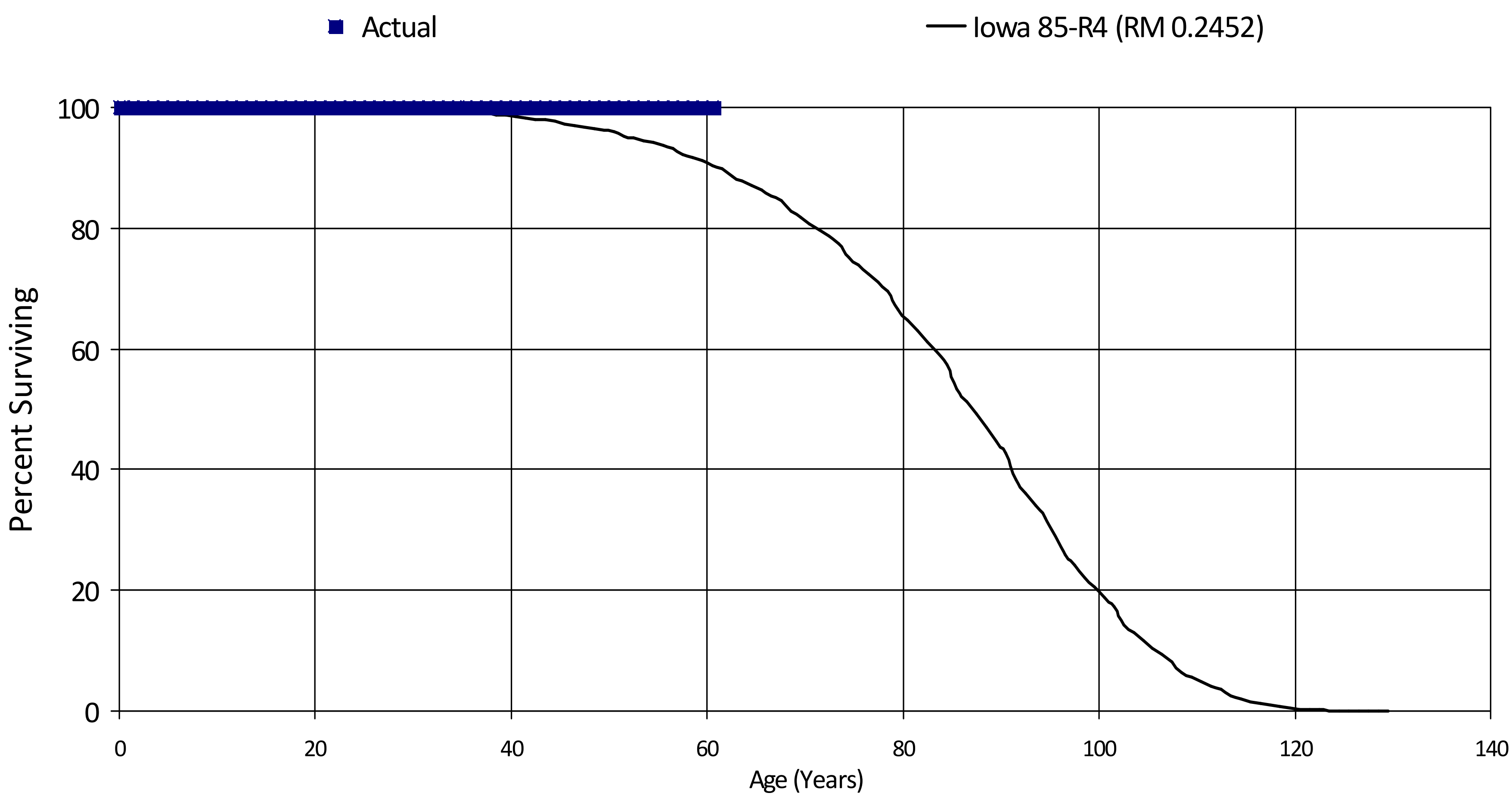
58.5	10,907,568	0	0.00000	1.00000	99.94
59.5	10,907,568	0	0.00000	1.00000	99.94
60.5	8,484,959	0	0.00000	1.00000	99.94
61.5	3,301,564	0	0.00000	1.00000	99.94
62.5	3,034,189	0	0.00000	1.00000	99.94
63.5	2,984,269	0	0.00000	1.00000	99.94
64.5	2,984,269	0	0.00000	1.00000	99.94
65.5	2,984,269	0	0.00000	1.00000	99.94
66.5	2,984,269	0	0.00000	1.00000	99.94
	Totals:	13,500			

BC Hydro Power Authority

Account 23201 - Penstock, Steel

Placement Band - 1925 - 2018 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23201 - Penstock, Steel

Placement Band - 1925 - 2018   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	410,680,827	0	0.00000	1.00000	100.00
0.5	410,680,827	0	0.00000	1.00000	100.00
1.5	410,680,827	0	0.00000	1.00000	100.00
2.5	134,499,422	0	0.00000	1.00000	100.00
3.5	130,732,066	0	0.00000	1.00000	100.00
4.5	121,073,476	0	0.00000	1.00000	100.00
5.5	121,073,476	0	0.00000	1.00000	100.00
6.5	121,073,476	0	0.00000	1.00000	100.00
7.5	121,073,476	0	0.00000	1.00000	100.00
8.5	121,073,476	0	0.00000	1.00000	100.00
9.5	113,854,495	0	0.00000	1.00000	100.00
10.5	77,280,726	0	0.00000	1.00000	100.00
11.5	76,438,614	0	0.00000	1.00000	100.00
12.5	58,151,106	0	0.00000	1.00000	100.00
13.5	58,151,106	0	0.00000	1.00000	100.00
14.5	58,151,106	0	0.00000	1.00000	100.00
15.5	58,030,653	0	0.00000	1.00000	100.00
16.5	58,030,653	0	0.00000	1.00000	100.00
17.5	57,703,072	0	0.00000	1.00000	100.00
18.5	57,703,072	0	0.00000	1.00000	100.00
19.5	57,682,929	0	0.00000	1.00000	100.00
20.5	57,682,929	0	0.00000	1.00000	100.00
21.5	57,682,929	0	0.00000	1.00000	100.00
22.5	57,682,929	0	0.00000	1.00000	100.00
23.5	57,682,929	0	0.00000	1.00000	100.00
24.5	57,682,929	0	0.00000	1.00000	100.00
25.5	57,634,673	0	0.00000	1.00000	100.00
26.5	55,843,324	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 23201 - Penstock, Steel

Placement Band - 1925 - 2018 Experience Band - 2020 - 2020

27.5	44,178,138	0	0.00000	1.00000	100.00
28.5	44,178,138	0	0.00000	1.00000	100.00
29.5	44,178,138	0	0.00000	1.00000	100.00
30.5	44,169,992	0	0.00000	1.00000	100.00
31.5	44,169,992	0	0.00000	1.00000	100.00
32.5	44,169,992	0	0.00000	1.00000	100.00
33.5	44,169,992	0	0.00000	1.00000	100.00
34.5	44,169,992	0	0.00000	1.00000	100.00
35.5	15,158,107	0	0.00000	1.00000	100.00
36.5	15,158,107	0	0.00000	1.00000	100.00
37.5	15,158,107	0	0.00000	1.00000	100.00
38.5	15,158,107	0	0.00000	1.00000	100.00
39.5	13,912,284	0	0.00000	1.00000	100.00
40.5	13,912,284	0	0.00000	1.00000	100.00
41.5	13,912,284	0	0.00000	1.00000	100.00
42.5	13,912,284	0	0.00000	1.00000	100.00
43.5	8,508,700	0	0.00000	1.00000	100.00
44.5	8,508,700	0	0.00000	1.00000	100.00
45.5	8,508,700	0	0.00000	1.00000	100.00
46.5	8,508,700	0	0.00000	1.00000	100.00
47.5	8,306,173	0	0.00000	1.00000	100.00
48.5	7,869,395	0	0.00000	1.00000	100.00
49.5	7,869,395	0	0.00000	1.00000	100.00
50.5	7,869,395	0	0.00000	1.00000	100.00
51.5	7,869,395	0	0.00000	1.00000	100.00
52.5	7,869,395	0	0.00000	1.00000	100.00
53.5	7,869,395	0	0.00000	1.00000	100.00
54.5	7,674,190	0	0.00000	1.00000	100.00
55.5	7,674,190	0	0.00000	1.00000	100.00
56.5	7,570,157	0	0.00000	1.00000	100.00
57.5	6,095,820	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 23201 - Penstock, Steel

Placement Band - 1925 - 2018 Experience Band - 2020 - 2020

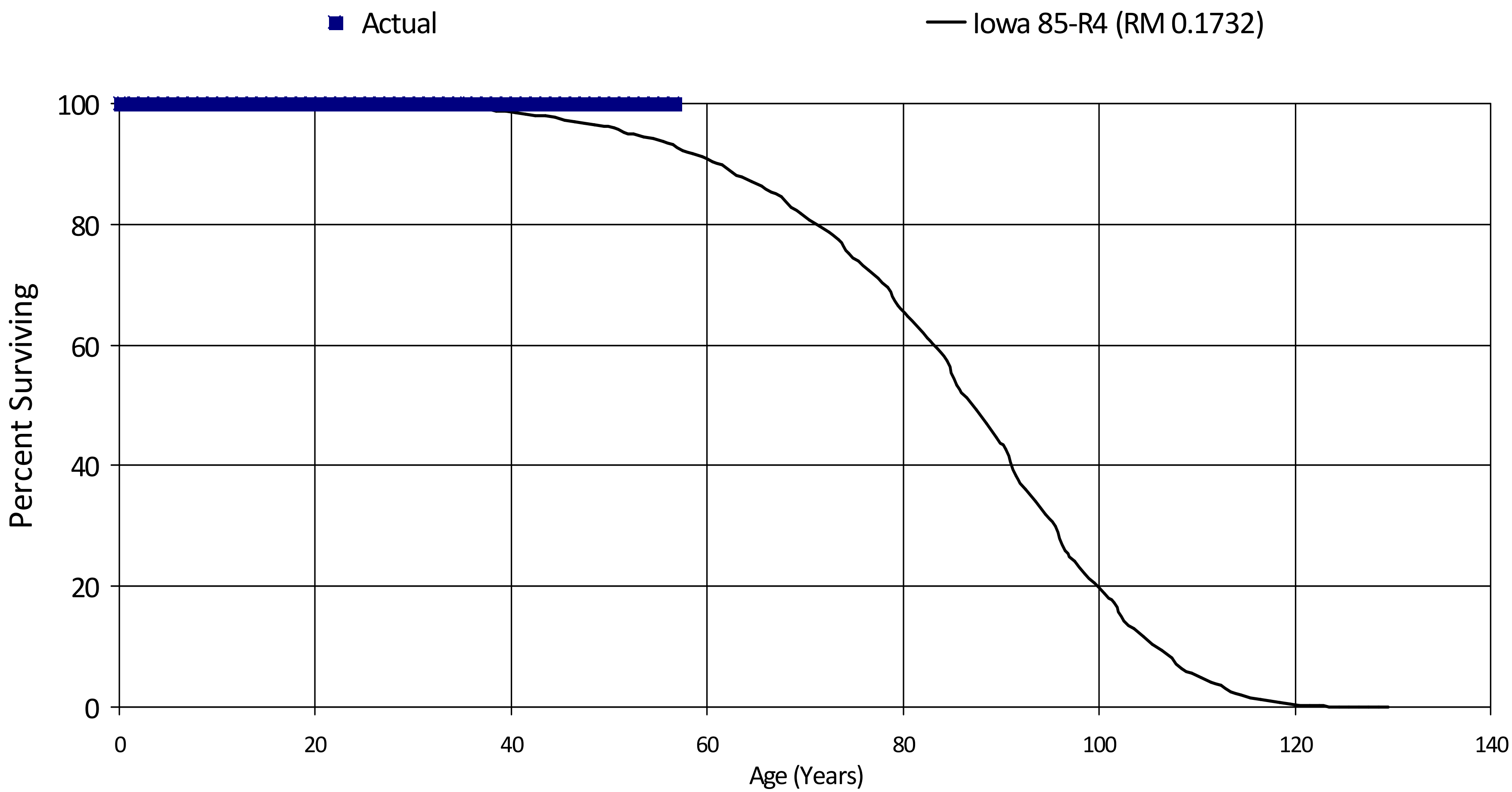
58.5	6,095,820	0	0.00000	1.00000	100.00
59.5	6,095,820	0	0.00000	1.00000	100.00
60.5	5,849,943	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 23202 - Penstock, Concrete

Placement Band - 1939 - 2010   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23202 - Penstock, Concrete

Placement Band - 1939 - 2010   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	85,009,389	0	0.00000	1.00000	100.00
0.5	85,009,389	0	0.00000	1.00000	100.00
1.5	85,009,389	0	0.00000	1.00000	100.00
2.5	85,009,389	0	0.00000	1.00000	100.00
3.5	85,009,389	0	0.00000	1.00000	100.00
4.5	85,009,389	0	0.00000	1.00000	100.00
5.5	85,009,389	0	0.00000	1.00000	100.00
6.5	85,009,389	0	0.00000	1.00000	100.00
7.5	85,009,389	0	0.00000	1.00000	100.00
8.5	85,009,389	0	0.00000	1.00000	100.00
9.5	85,009,389	0	0.00000	1.00000	100.00
10.5	66,789,791	0	0.00000	1.00000	100.00
11.5	63,401,986	0	0.00000	1.00000	100.00
12.5	63,401,986	0	0.00000	1.00000	100.00
13.5	63,401,986	0	0.00000	1.00000	100.00
14.5	63,401,986	0	0.00000	1.00000	100.00
15.5	63,401,986	0	0.00000	1.00000	100.00
16.5	63,401,986	0	0.00000	1.00000	100.00
17.5	58,526,538	0	0.00000	1.00000	100.00
18.5	58,526,538	0	0.00000	1.00000	100.00
19.5	58,526,538	0	0.00000	1.00000	100.00
20.5	58,526,538	0	0.00000	1.00000	100.00
21.5	58,526,538	0	0.00000	1.00000	100.00
22.5	58,526,538	0	0.00000	1.00000	100.00
23.5	54,077,694	0	0.00000	1.00000	100.00
24.5	54,077,694	0	0.00000	1.00000	100.00
25.5	54,077,694	0	0.00000	1.00000	100.00
26.5	54,077,694	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 23202 - Penstock, Concrete

Placement Band - 1939 - 2010   Experience Band - 2020 - 2020

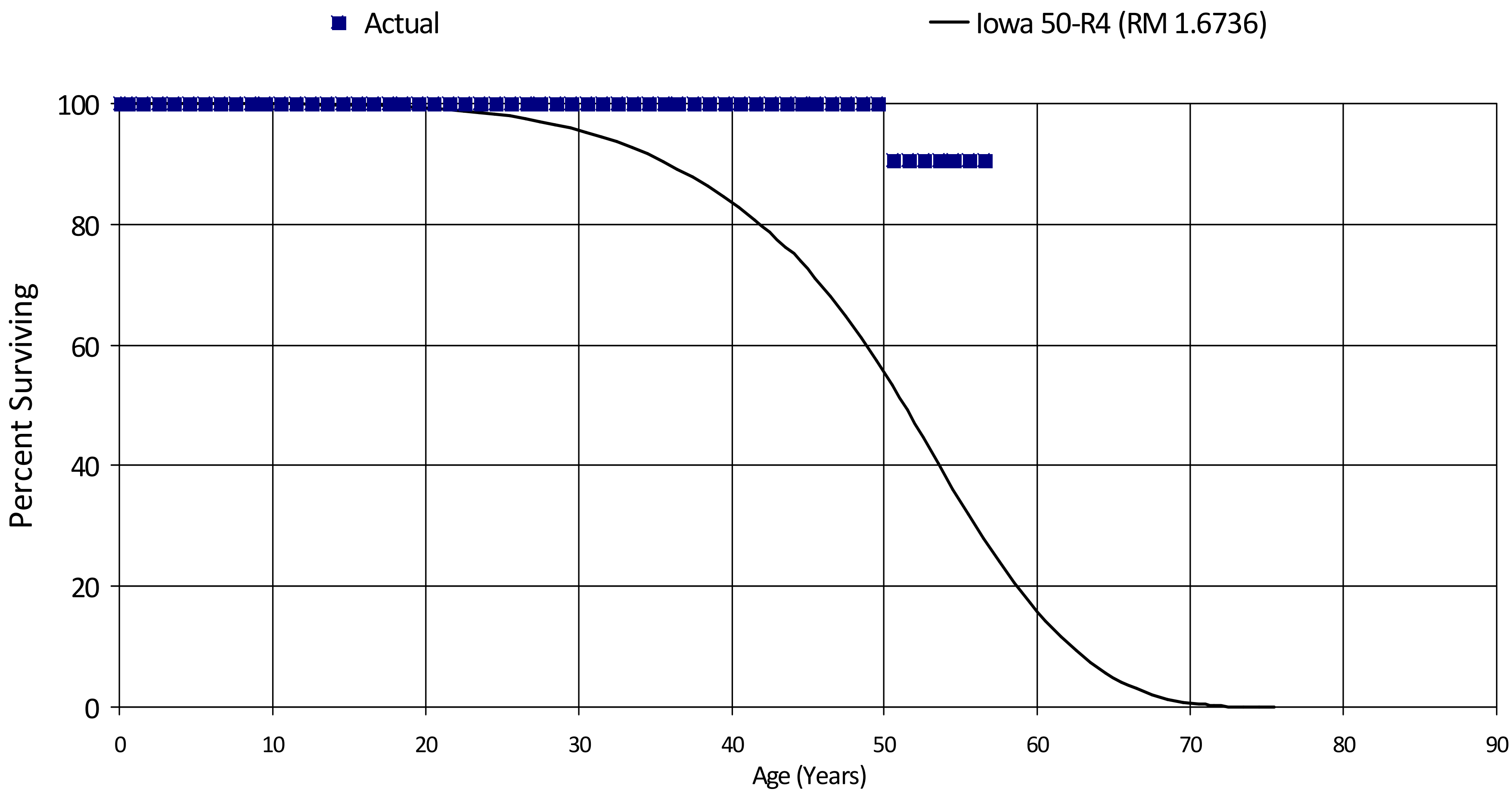
27.5	54,077,694	0	0.00000	1.00000	100.00
28.5	54,077,694	0	0.00000	1.00000	100.00
29.5	54,077,694	0	0.00000	1.00000	100.00
30.5	54,077,694	0	0.00000	1.00000	100.00
31.5	54,077,694	0	0.00000	1.00000	100.00
32.5	54,077,694	0	0.00000	1.00000	100.00
33.5	54,077,694	0	0.00000	1.00000	100.00
34.5	54,077,694	0	0.00000	1.00000	100.00
35.5	54,077,694	0	0.00000	1.00000	100.00
36.5	54,077,694	0	0.00000	1.00000	100.00
37.5	54,077,694	0	0.00000	1.00000	100.00
38.5	54,077,694	0	0.00000	1.00000	100.00
39.5	54,077,694	0	0.00000	1.00000	100.00
40.5	54,077,694	0	0.00000	1.00000	100.00
41.5	54,077,694	0	0.00000	1.00000	100.00
42.5	54,077,694	0	0.00000	1.00000	100.00
43.5	54,077,694	0	0.00000	1.00000	100.00
44.5	54,077,694	0	0.00000	1.00000	100.00
45.5	54,077,694	0	0.00000	1.00000	100.00
46.5	54,077,694	0	0.00000	1.00000	100.00
47.5	22,852,168	0	0.00000	1.00000	100.00
48.5	22,852,168	0	0.00000	1.00000	100.00
49.5	22,852,168	0	0.00000	1.00000	100.00
50.5	21,728,538	0	0.00000	1.00000	100.00
51.5	8,811,002	0	0.00000	1.00000	100.00
52.5	3,043,022	0	0.00000	1.00000	100.00
53.5	3,043,022	0	0.00000	1.00000	100.00
54.5	3,043,022	0	0.00000	1.00000	100.00
55.5	3,043,022	0	0.00000	1.00000	100.00
56.5	3,043,022	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 23203 - Penstock, Wood

Placement Band - 1948 - 2007   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23203 - Penstock, Wood

Placement Band - 1948 - 2007 Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	279,220	0	0.00000	1.00000	100.00
0.5	279,220	0	0.00000	1.00000	100.00
1.5	279,220	0	0.00000	1.00000	100.00
2.5	279,220	0	0.00000	1.00000	100.00
3.5	279,220	0	0.00000	1.00000	100.00
4.5	279,220	0	0.00000	1.00000	100.00
5.5	279,220	0	0.00000	1.00000	100.00
6.5	279,220	0	0.00000	1.00000	100.00
7.5	279,220	0	0.00000	1.00000	100.00
8.5	279,220	0	0.00000	1.00000	100.00
9.5	279,220	0	0.00000	1.00000	100.00
10.5	279,220	0	0.00000	1.00000	100.00
11.5	279,220	0	0.00000	1.00000	100.00
12.5	279,220	0	0.00000	1.00000	100.00
13.5	236,555	0	0.00000	1.00000	100.00
14.5	129,798	0	0.00000	1.00000	100.00
15.5	129,798	0	0.00000	1.00000	100.00
16.5	129,798	0	0.00000	1.00000	100.00
17.5	129,798	0	0.00000	1.00000	100.00
18.5	129,798	0	0.00000	1.00000	100.00
19.5	129,798	0	0.00000	1.00000	100.00
20.5	129,798	0	0.00000	1.00000	100.00
21.5	129,798	0	0.00000	1.00000	100.00
22.5	129,798	0	0.00000	1.00000	100.00
23.5	129,798	0	0.00000	1.00000	100.00
24.5	129,798	0	0.00000	1.00000	100.00
25.5	129,798	0	0.00000	1.00000	100.00
26.5	129,798	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 23203 - Penstock, Wood

Placement Band - 1948 - 2007   Experience Band - 2013 - 2020

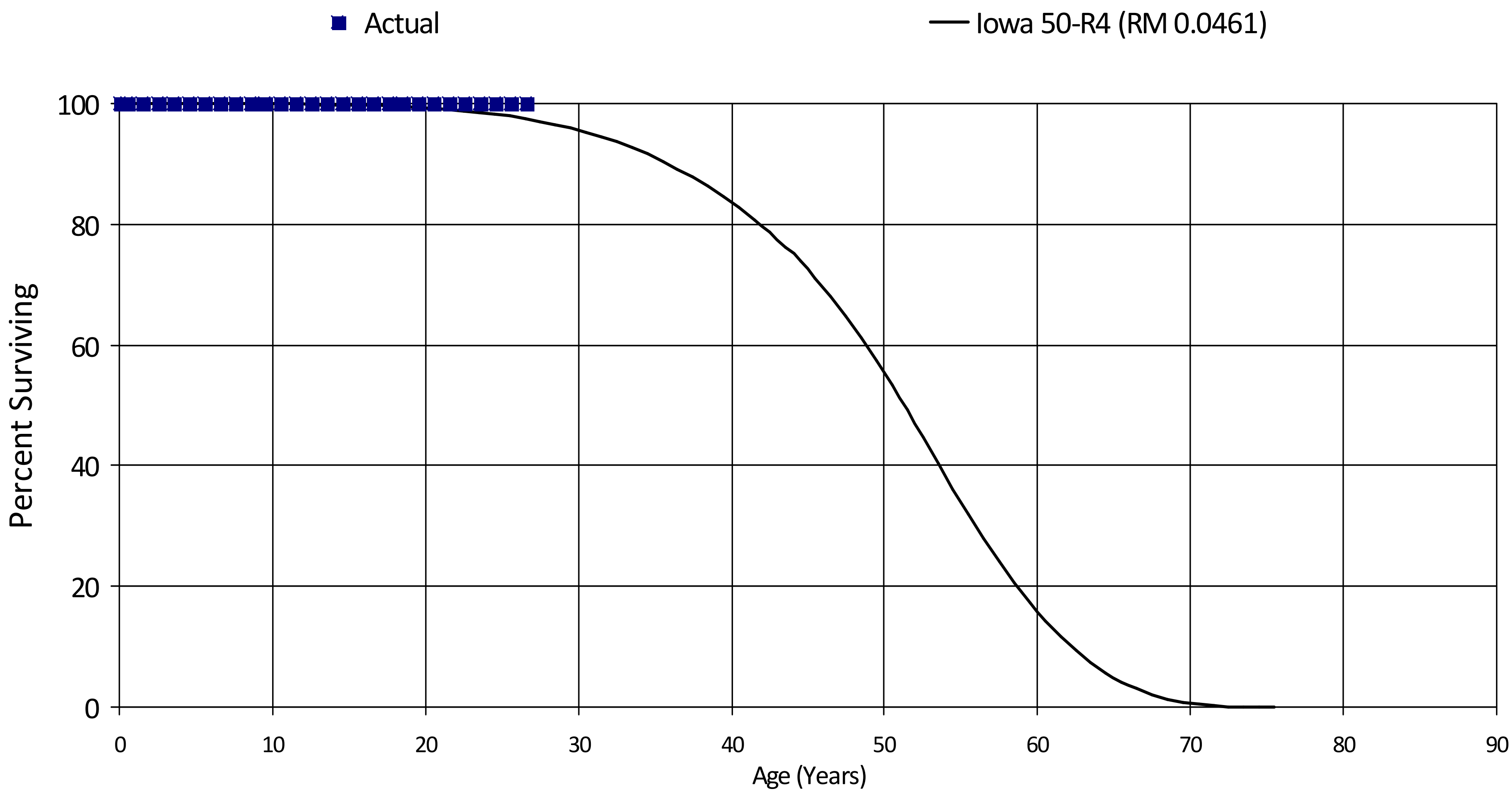
27.5	129,798	0	0.00000	1.00000	100.00
28.5	129,798	0	0.00000	1.00000	100.00
29.5	129,798	0	0.00000	1.00000	100.00
30.5	129,798	0	0.00000	1.00000	100.00
31.5	129,798	0	0.00000	1.00000	100.00
32.5	129,798	0	0.00000	1.00000	100.00
33.5	129,798	0	0.00000	1.00000	100.00
34.5	129,798	0	0.00000	1.00000	100.00
35.5	129,798	0	0.00000	1.00000	100.00
36.5	129,798	0	0.00000	1.00000	100.00
37.5	129,798	0	0.00000	1.00000	100.00
38.5	129,798	0	0.00000	1.00000	100.00
39.5	129,798	0	0.00000	1.00000	100.00
40.5	129,798	0	0.00000	1.00000	100.00
41.5	129,798	0	0.00000	1.00000	100.00
42.5	129,798	0	0.00000	1.00000	100.00
43.5	129,798	0	0.00000	1.00000	100.00
44.5	129,798	0	0.00000	1.00000	100.00
45.5	129,798	0	0.00000	1.00000	100.00
46.5	129,798	0	0.00000	1.00000	100.00
47.5	129,798	0	0.00000	1.00000	100.00
48.5	129,798	0	0.00000	1.00000	100.00
49.5	129,798	12,113	0.09332	0.90668	100.00
50.5	117,685	0	0.00000	1.00000	90.67
51.5	117,685	0	0.00000	1.00000	90.67
52.5	117,685	0	0.00000	1.00000	90.67
53.5	117,685	0	0.00000	1.00000	90.67
54.5	117,685	0	0.00000	1.00000	90.67
55.5	117,685	0	0.00000	1.00000	90.67
56.5	117,685	0	0.00000	1.00000	90.67
	Totals:	12,113			

BC Hydro Power Authority

Account 23302 - Tank, Surge, Steel

Placement Band - 1931 - 2018   Experience Band - 2019 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23302 - Tank, Surge, Steel

Placement Band - 1931 - 2018 Experience Band - 2019 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	30,640,497	0	0.00000	1.00000	100.00
0.5	30,640,497	0	0.00000	1.00000	100.00
1.5	30,640,497	0	0.00000	1.00000	100.00
2.5	14,370,905	0	0.00000	1.00000	100.00
3.5	14,370,905	0	0.00000	1.00000	100.00
4.5	14,370,905	0	0.00000	1.00000	100.00
5.5	12,161,773	0	0.00000	1.00000	100.00
6.5	12,161,773	0	0.00000	1.00000	100.00
7.5	12,161,773	0	0.00000	1.00000	100.00
8.5	12,161,773	0	0.00000	1.00000	100.00
9.5	12,161,773	0	0.00000	1.00000	100.00
10.5	12,161,773	0	0.00000	1.00000	100.00
11.5	12,161,773	0	0.00000	1.00000	100.00
12.5	8,743,526	0	0.00000	1.00000	100.00
13.5	8,743,526	0	0.00000	1.00000	100.00
14.5	8,743,526	0	0.00000	1.00000	100.00
15.5	8,743,526	0	0.00000	1.00000	100.00
16.5	8,743,526	0	0.00000	1.00000	100.00
17.5	6,232,043	0	0.00000	1.00000	100.00
18.5	6,232,043	0	0.00000	1.00000	100.00
19.5	6,232,043	0	0.00000	1.00000	100.00
20.5	6,232,043	0	0.00000	1.00000	100.00
21.5	6,232,043	0	0.00000	1.00000	100.00
22.5	6,232,043	0	0.00000	1.00000	100.00
23.5	6,232,043	0	0.00000	1.00000	100.00
24.5	6,232,043	0	0.00000	1.00000	100.00
25.5	6,232,043	0	0.00000	1.00000	100.00
26.5	6,232,043	6,232,043	1.00000		100.00

BC Hydro Power Authority

Account 23302 - Tank, Surge, Steel

Placement Band - 1931 - 2018   Experience Band - 2019 - 2020

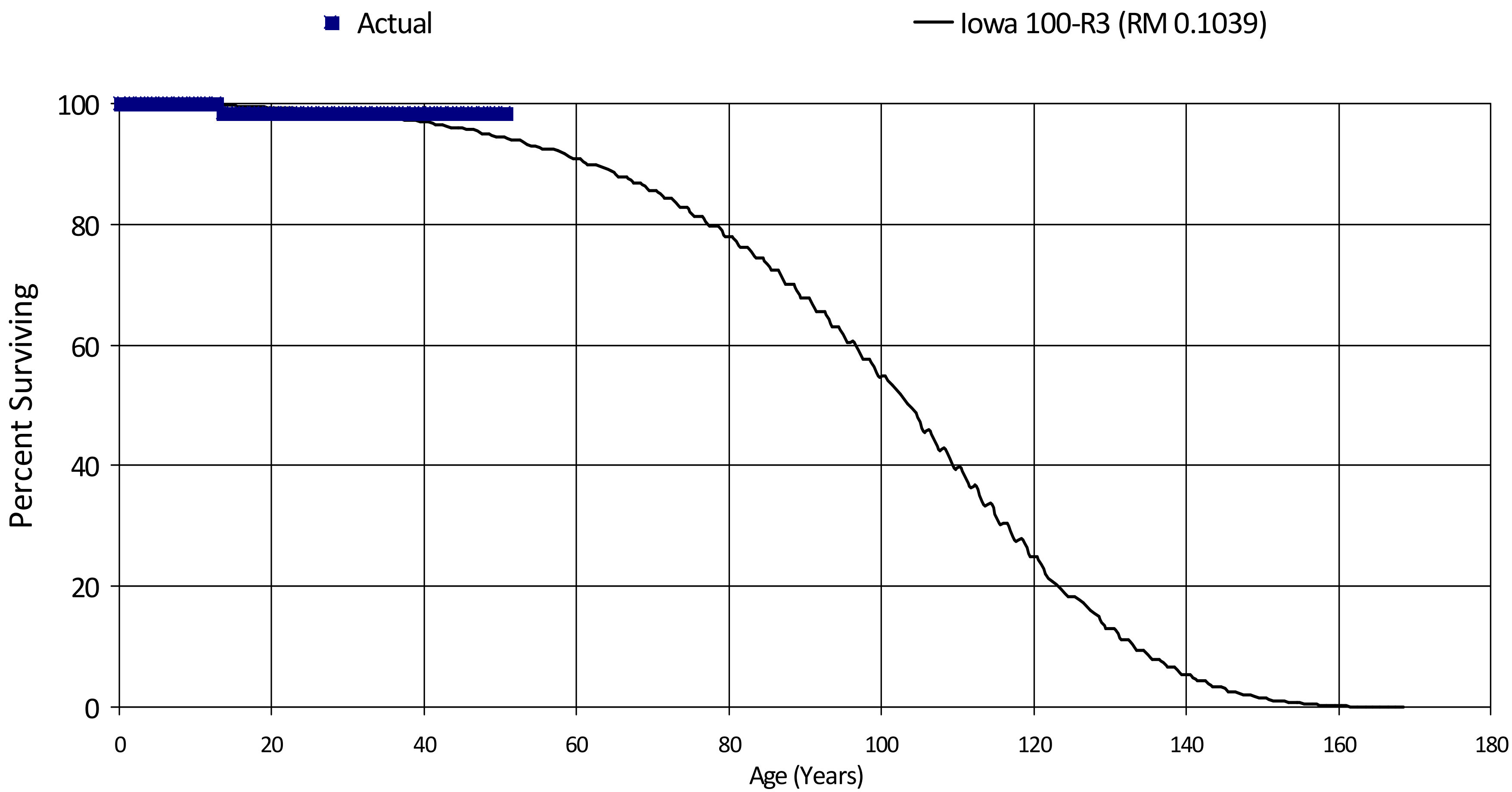
Totals: 6,232,043

BC Hydro Power Authority

Account 23401 - Tailrace

Placement Band - 1957 - 2018   Experience Band - 2019 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23401 - Tailrace

Placement Band - 1957 - 2018   Experience Band - 2019 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	157,263,328	0	0.00000	1.00000	100.00
0.5	157,263,328	0	0.00000	1.00000	100.00
1.5	157,263,328	0	0.00000	1.00000	100.00
2.5	60,353,366	0	0.00000	1.00000	100.00
3.5	60,353,366	0	0.00000	1.00000	100.00
4.5	60,353,366	0	0.00000	1.00000	100.00
5.5	58,841,543	0	0.00000	1.00000	100.00
6.5	58,841,543	0	0.00000	1.00000	100.00
7.5	58,779,804	0	0.00000	1.00000	100.00
8.5	58,779,804	0	0.00000	1.00000	100.00
9.5	58,779,804	0	0.00000	1.00000	100.00
10.5	54,768,781	0	0.00000	1.00000	100.00
11.5	54,768,781	0	0.00000	1.00000	100.00
12.5	54,053,888	878,310	0.01625	0.98375	100.00
13.5	53,175,578	0	0.00000	1.00000	98.38
14.5	52,431,702	0	0.00000	1.00000	98.38
15.5	52,431,702	0	0.00000	1.00000	98.38
16.5	51,252,979	0	0.00000	1.00000	98.38
17.5	51,252,979	0	0.00000	1.00000	98.38
18.5	51,252,979	0	0.00000	1.00000	98.38
19.5	51,252,979	0	0.00000	1.00000	98.38
20.5	49,050,290	0	0.00000	1.00000	98.38
21.5	49,050,290	0	0.00000	1.00000	98.38
22.5	49,050,290	0	0.00000	1.00000	98.38
23.5	49,050,290	0	0.00000	1.00000	98.38
24.5	49,050,290	0	0.00000	1.00000	98.38
25.5	49,050,290	0	0.00000	1.00000	98.38
26.5	49,050,290	0	0.00000	1.00000	98.38

BC Hydro Power Authority

Account 23401 - Tailrace

Placement Band - 1957 - 2018 Experience Band - 2019 - 2020

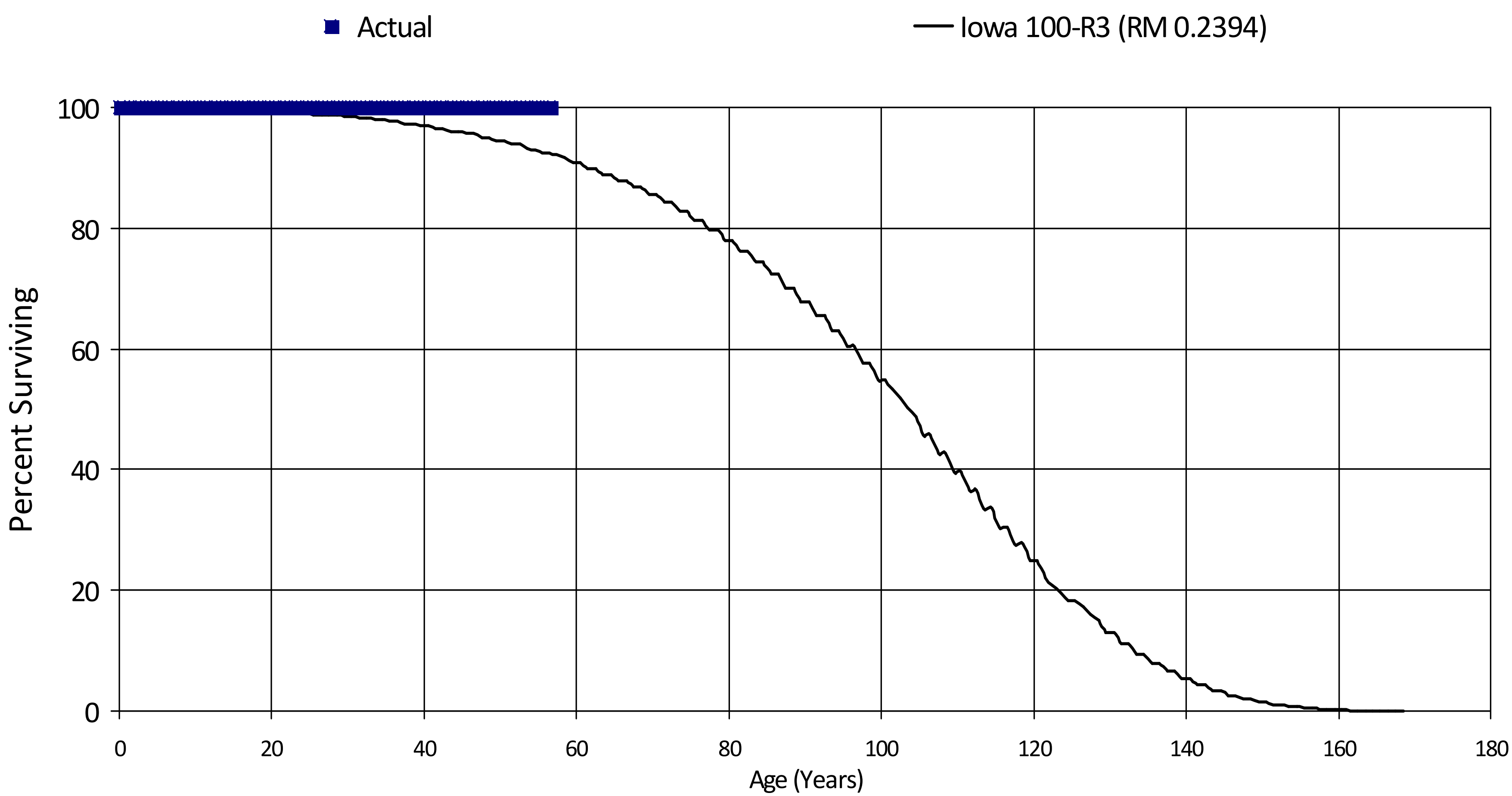
27.5	49,050,290	0	0.00000	1.00000	98.38
28.5	49,050,290	0	0.00000	1.00000	98.38
29.5	49,050,290	0	0.00000	1.00000	98.38
30.5	45,175,519	0	0.00000	1.00000	98.38
31.5	45,175,519	0	0.00000	1.00000	98.38
32.5	45,175,519	0	0.00000	1.00000	98.38
33.5	45,175,519	0	0.00000	1.00000	98.38
34.5	45,175,519	0	0.00000	1.00000	98.38
35.5	45,175,519	0	0.00000	1.00000	98.38
36.5	45,175,519	0	0.00000	1.00000	98.38
37.5	45,175,519	0	0.00000	1.00000	98.38
38.5	45,175,519	0	0.00000	1.00000	98.38
39.5	42,608,578	0	0.00000	1.00000	98.38
40.5	42,608,578	0	0.00000	1.00000	98.38
41.5	42,608,578	0	0.00000	1.00000	98.38
42.5	42,608,578	0	0.00000	1.00000	98.38
43.5	42,608,578	0	0.00000	1.00000	98.38
44.5	42,608,578	0	0.00000	1.00000	98.38
45.5	42,608,578	0	0.00000	1.00000	98.38
46.5	42,594,615	0	0.00000	1.00000	98.38
47.5	18,925,609	0	0.00000	1.00000	98.38
48.5	18,925,609	0	0.00000	1.00000	98.38
49.5	18,925,609	0	0.00000	1.00000	98.38
50.5	18,925,609	0	0.00000	1.00000	98.38
	Totals:	878,310			

BC Hydro Power Authority

Account 23501 - Canal

Placement Band - 1963 - 2017 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23501 - Canal

Placement Band - 1963 - 2017   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	11,721,791	0	0.00000	1.00000	100.00
0.5	11,721,791	0	0.00000	1.00000	100.00
1.5	11,721,791	0	0.00000	1.00000	100.00
2.5	11,721,791	0	0.00000	1.00000	100.00
3.5	7,817,729	0	0.00000	1.00000	100.00
4.5	7,817,729	0	0.00000	1.00000	100.00
5.5	7,817,729	0	0.00000	1.00000	100.00
6.5	1,355,481	0	0.00000	1.00000	100.00
7.5	1,355,481	0	0.00000	1.00000	100.00
8.5	1,355,481	0	0.00000	1.00000	100.00
9.5	1,355,481	0	0.00000	1.00000	100.00
10.5	1,355,481	0	0.00000	1.00000	100.00
11.5	1,355,481	0	0.00000	1.00000	100.00
12.5	1,355,481	0	0.00000	1.00000	100.00
13.5	1,028,782	0	0.00000	1.00000	100.00
14.5	1,028,782	0	0.00000	1.00000	100.00
15.5	1,028,782	0	0.00000	1.00000	100.00
16.5	1,028,782	0	0.00000	1.00000	100.00
17.5	1,028,782	0	0.00000	1.00000	100.00
18.5	1,028,782	0	0.00000	1.00000	100.00
19.5	965,303	0	0.00000	1.00000	100.00
20.5	965,303	0	0.00000	1.00000	100.00
21.5	965,303	0	0.00000	1.00000	100.00
22.5	965,303	0	0.00000	1.00000	100.00
23.5	965,303	0	0.00000	1.00000	100.00
24.5	965,303	0	0.00000	1.00000	100.00
25.5	965,303	0	0.00000	1.00000	100.00
26.5	965,303	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 23501 - Canal

Placement Band - 1963 - 2017 Experience Band - 2020 - 2020

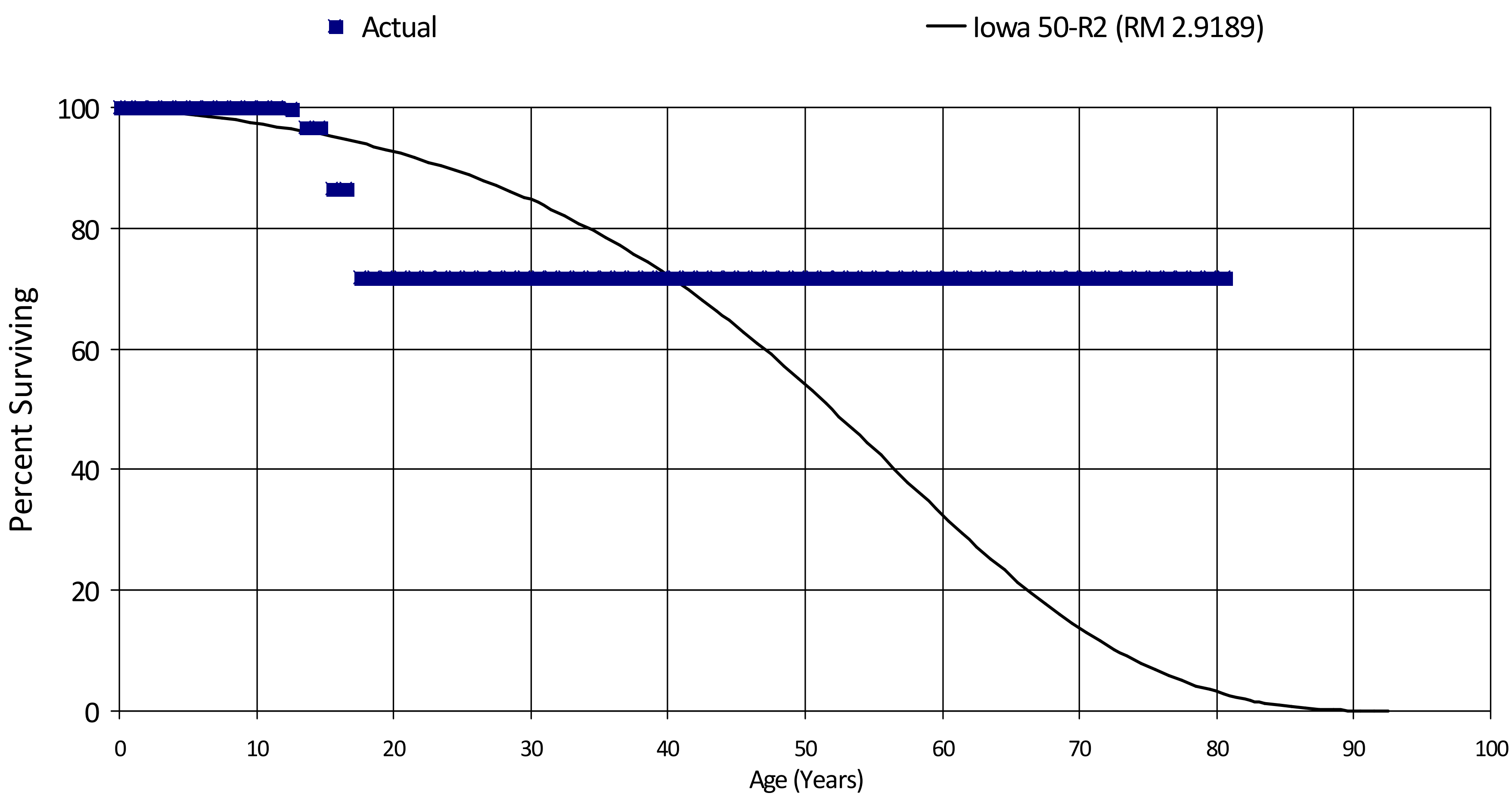
27.5	965,303	0	0.00000	1.00000	100.00
28.5	965,303	0	0.00000	1.00000	100.00
29.5	965,303	0	0.00000	1.00000	100.00
30.5	965,303	0	0.00000	1.00000	100.00
31.5	965,303	0	0.00000	1.00000	100.00
32.5	965,303	0	0.00000	1.00000	100.00
33.5	965,303	0	0.00000	1.00000	100.00
34.5	965,303	0	0.00000	1.00000	100.00
35.5	965,303	0	0.00000	1.00000	100.00
36.5	965,303	0	0.00000	1.00000	100.00
37.5	965,303	0	0.00000	1.00000	100.00
38.5	965,303	0	0.00000	1.00000	100.00
39.5	965,303	0	0.00000	1.00000	100.00
40.5	965,303	0	0.00000	1.00000	100.00
41.5	965,303	0	0.00000	1.00000	100.00
42.5	965,303	0	0.00000	1.00000	100.00
43.5	965,303	0	0.00000	1.00000	100.00
44.5	965,303	0	0.00000	1.00000	100.00
45.5	965,303	0	0.00000	1.00000	100.00
46.5	965,303	0	0.00000	1.00000	100.00
47.5	965,303	0	0.00000	1.00000	100.00
48.5	965,303	0	0.00000	1.00000	100.00
49.5	965,303	0	0.00000	1.00000	100.00
50.5	965,303	0	0.00000	1.00000	100.00
51.5	965,303	0	0.00000	1.00000	100.00
52.5	965,303	0	0.00000	1.00000	100.00
53.5	965,303	0	0.00000	1.00000	100.00
54.5	965,303	0	0.00000	1.00000	100.00
55.5	965,303	0	0.00000	1.00000	100.00
56.5	965,303	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 23601 - Stoplogs, Steel

Placement Band - 1939 - 2018   Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23601 - Stoplogs, Steel

Placement Band - 1939 - 2018   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	10,817,818	0	0.00000	1.00000	100.00
0.5	10,817,818	0	0.00000	1.00000	100.00
1.5	10,817,818	0	0.00000	1.00000	100.00
2.5	10,593,224	0	0.00000	1.00000	100.00
3.5	9,308,570	0	0.00000	1.00000	100.00
4.5	9,308,570	0	0.00000	1.00000	100.00
5.5	6,427,463	0	0.00000	1.00000	100.00
6.5	6,427,463	0	0.00000	1.00000	100.00
7.5	6,387,572	0	0.00000	1.00000	100.00
8.5	6,387,572	0	0.00000	1.00000	100.00
9.5	6,387,572	0	0.00000	1.00000	100.00
10.5	6,387,572	0	0.00000	1.00000	100.00
11.5	6,387,572	10,358	0.00162	0.99838	100.00
12.5	5,566,321	170,822	0.03069	0.96931	99.84
13.5	4,912,983	0	0.00000	1.00000	96.78
14.5	4,634,357	489,998	0.10573	0.89427	96.78
15.5	4,144,360	0	0.00000	1.00000	86.55
16.5	4,141,896	704,459	0.17008	0.82992	86.55
17.5	3,437,437	0	0.00000	1.00000	71.83
18.5	2,787,042	0	0.00000	1.00000	71.83
19.5	2,651,758	0	0.00000	1.00000	71.83
20.5	2,651,758	0	0.00000	1.00000	71.83
21.5	2,651,758	0	0.00000	1.00000	71.83
22.5	2,651,758	0	0.00000	1.00000	71.83
23.5	2,509,600	0	0.00000	1.00000	71.83
24.5	2,509,600	0	0.00000	1.00000	71.83
25.5	2,482,175	0	0.00000	1.00000	71.83
26.5	2,422,068	0	0.00000	1.00000	71.83

BC Hydro Power Authority

Account 23601 - Stoplogs, Steel

Placement Band - 1939 - 2018   Experience Band - 2012 - 2020

27.5	1,873,052	0	0.00000	1.00000	71.83
28.5	1,873,052	0	0.00000	1.00000	71.83
29.5	1,873,052	0	0.00000	1.00000	71.83
30.5	1,873,052	0	0.00000	1.00000	71.83
31.5	1,873,052	0	0.00000	1.00000	71.83
32.5	1,873,052	0	0.00000	1.00000	71.83
33.5	1,873,052	0	0.00000	1.00000	71.83
34.5	1,873,052	0	0.00000	1.00000	71.83
35.5	1,046,808	0	0.00000	1.00000	71.83
36.5	1,046,808	0	0.00000	1.00000	71.83
37.5	1,046,808	0	0.00000	1.00000	71.83
38.5	1,046,808	0	0.00000	1.00000	71.83
39.5	1,046,808	0	0.00000	1.00000	71.83
40.5	1,046,808	0	0.00000	1.00000	71.83
41.5	1,046,808	0	0.00000	1.00000	71.83
42.5	903,040	0	0.00000	1.00000	71.83
43.5	903,040	0	0.00000	1.00000	71.83
44.5	832,335	0	0.00000	1.00000	71.83
45.5	832,335	0	0.00000	1.00000	71.83
46.5	832,335	0	0.00000	1.00000	71.83
47.5	832,335	0	0.00000	1.00000	71.83
48.5	832,335	0	0.00000	1.00000	71.83
49.5	832,335	0	0.00000	1.00000	71.83
50.5	832,335	0	0.00000	1.00000	71.83
51.5	457,415	0	0.00000	1.00000	71.83
52.5	457,415	0	0.00000	1.00000	71.83
53.5	457,415	0	0.00000	1.00000	71.83
54.5	457,415	0	0.00000	1.00000	71.83
55.5	457,415	0	0.00000	1.00000	71.83
56.5	457,125	0	0.00000	1.00000	71.83
57.5	412,167	0	0.00000	1.00000	71.83

BC Hydro Power Authority

Account 23601 - Stoplogs, Steel

Placement Band - 1939 - 2018   Experience Band - 2012 - 2020

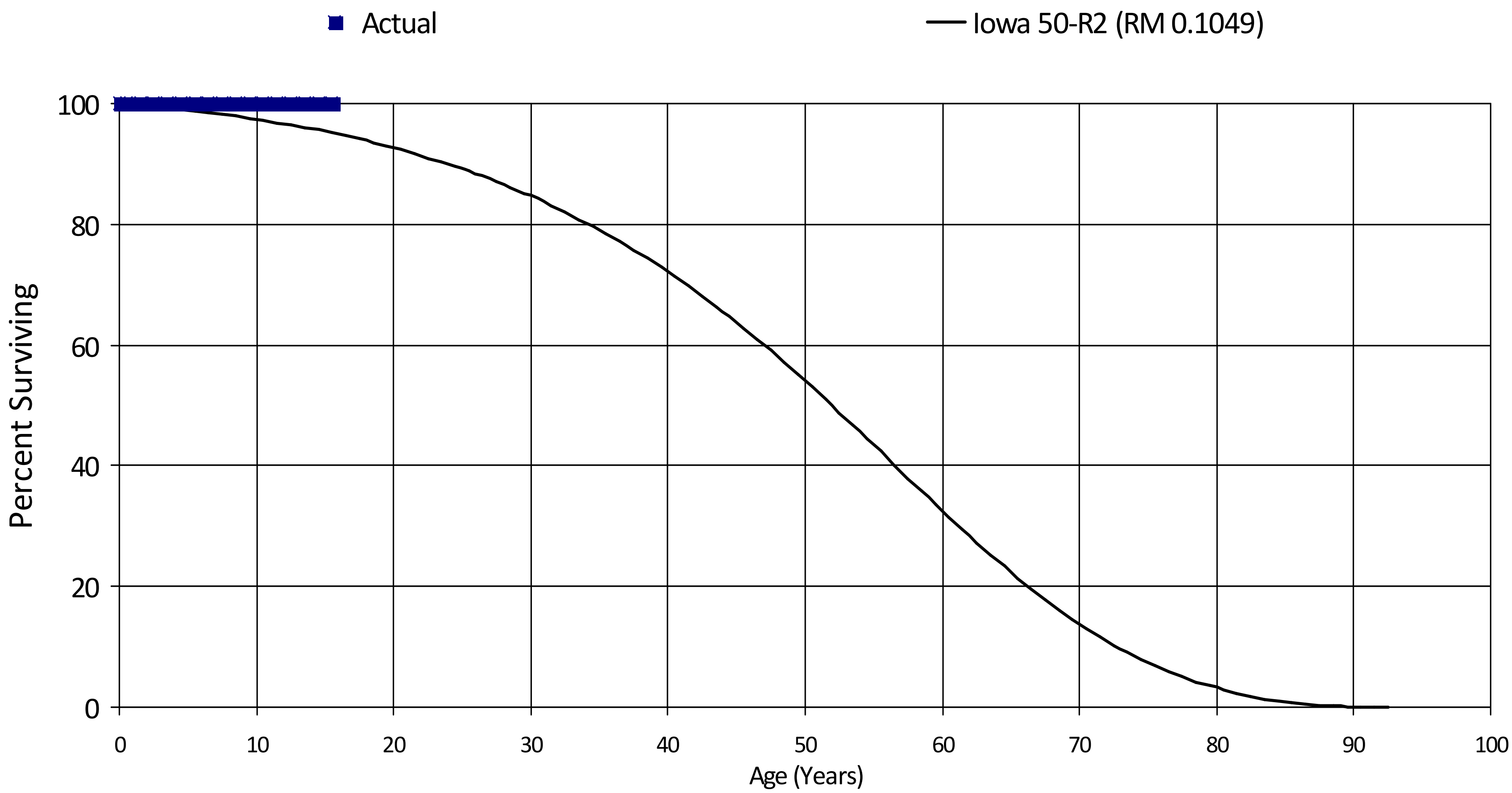
58.5	412,167	0	0.00000	1.00000	71.83
59.5	412,167	0	0.00000	1.00000	71.83
60.5	412,167	0	0.00000	1.00000	71.83
61.5	409,164	0	0.00000	1.00000	71.83
62.5	409,164	0	0.00000	1.00000	71.83
63.5	409,164	0	0.00000	1.00000	71.83
64.5	409,164	0	0.00000	1.00000	71.83
65.5	409,164	0	0.00000	1.00000	71.83
66.5	409,164	0	0.00000	1.00000	71.83
67.5	409,164	0	0.00000	1.00000	71.83
68.5	409,164	0	0.00000	1.00000	71.83
69.5	409,164	0	0.00000	1.00000	71.83
70.5	409,164	0	0.00000	1.00000	71.83
71.5	409,164	0	0.00000	1.00000	71.83
72.5	409,164	0	0.00000	1.00000	71.83
73.5	409,164	0	0.00000	1.00000	71.83
74.5	409,164	0	0.00000	1.00000	71.83
75.5	409,164	0	0.00000	1.00000	71.83
76.5	409,164	0	0.00000	1.00000	71.83
77.5	409,164	0	0.00000	1.00000	71.83
78.5	409,164	0	0.00000	1.00000	71.83
79.5	409,164	0	0.00000	1.00000	71.83
80.5	409,164	0	0.00000	1.00000	71.83
	Totals:	1,375,637			

BC Hydro Power Authority

Account 23602 - Stoplogs, Wood

Placement Band - 1994 - 2018 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23602 - Stoplogs, Wood

Placement Band - 1994 - 2018   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

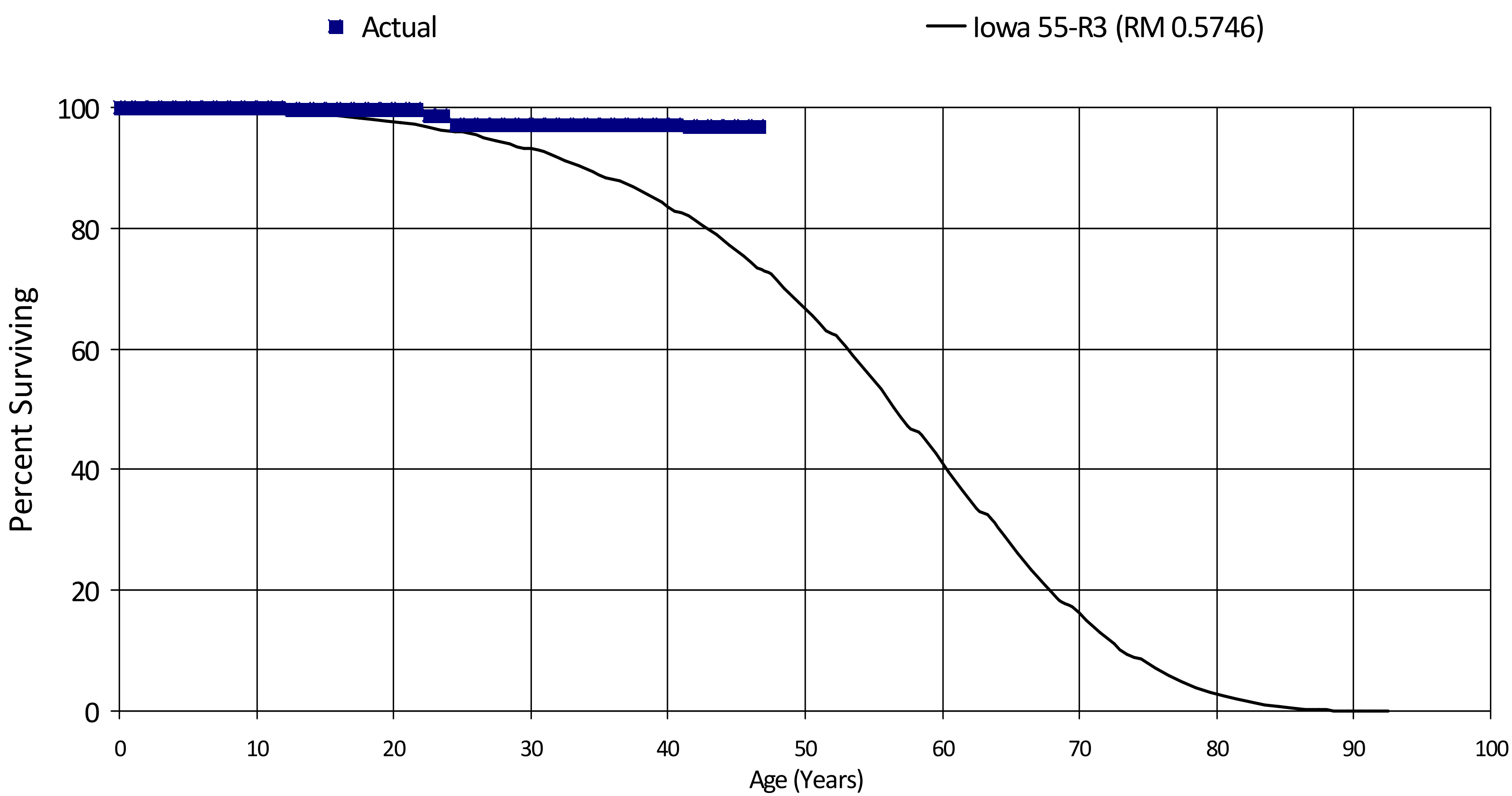
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,418,161	0	0.00000	1.00000	100.00
0.5	2,418,161	0	0.00000	1.00000	100.00
1.5	2,418,161	0	0.00000	1.00000	100.00
2.5	1,676,199	0	0.00000	1.00000	100.00
3.5	100,774	0	0.00000	1.00000	100.00
4.5	100,774	0	0.00000	1.00000	100.00
5.5	64,736	0	0.00000	1.00000	100.00
6.5	64,736	0	0.00000	1.00000	100.00
7.5	64,736	0	0.00000	1.00000	100.00
8.5	64,736	0	0.00000	1.00000	100.00
9.5	64,736	0	0.00000	1.00000	100.00
10.5	64,736	0	0.00000	1.00000	100.00
11.5	64,736	0	0.00000	1.00000	100.00
12.5	64,736	0	0.00000	1.00000	100.00
13.5	64,736	0	0.00000	1.00000	100.00
14.5	64,736	0	0.00000	1.00000	100.00
15.5	64,736	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 23603 - Hoist, Gate

Placement Band - 1904 - 2020   Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23603 - Hoist, Gate

Placement Band - 1904 - 2020   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	98,529,909	0	0.00000	1.00000	100.00
0.5	98,213,884	0	0.00000	1.00000	100.00
1.5	98,213,884	0	0.00000	1.00000	100.00
2.5	97,723,468	0	0.00000	1.00000	100.00
3.5	95,835,109	0	0.00000	1.00000	100.00
4.5	85,643,986	0	0.00000	1.00000	100.00
5.5	83,434,711	0	0.00000	1.00000	100.00
6.5	82,290,943	0	0.00000	1.00000	100.00
7.5	76,660,043	0	0.00000	1.00000	100.00
8.5	66,644,907	0	0.00000	1.00000	100.00
9.5	62,707,607	0	0.00000	1.00000	100.00
10.5	35,238,895	0	0.00000	1.00000	100.00
11.5	34,140,375	66,829	0.00196	0.99804	100.00
12.5	32,933,200	0	0.00000	1.00000	99.80
13.5	32,933,200	0	0.00000	1.00000	99.80
14.5	32,701,179	0	0.00000	1.00000	99.80
15.5	23,533,183	0	0.00000	1.00000	99.80
16.5	23,432,558	0	0.00000	1.00000	99.80
17.5	23,432,558	0	0.00000	1.00000	99.80
18.5	23,432,558	0	0.00000	1.00000	99.80
19.5	23,432,558	0	0.00000	1.00000	99.80
20.5	23,432,558	0	0.00000	1.00000	99.80
21.5	23,432,558	255,578	0.01091	0.98909	99.80
22.5	23,031,888	0	0.00000	1.00000	98.71
23.5	23,031,888	347,650	0.01509	0.98491	98.71
24.5	22,313,076	0	0.00000	1.00000	97.22
25.5	22,313,076	0	0.00000	1.00000	97.22
26.5	21,873,171	0	0.00000	1.00000	97.22

BC Hydro Power Authority

Account 23603 - Hoist, Gate

Placement Band - 1904 - 2020 Experience Band - 2012 - 2020

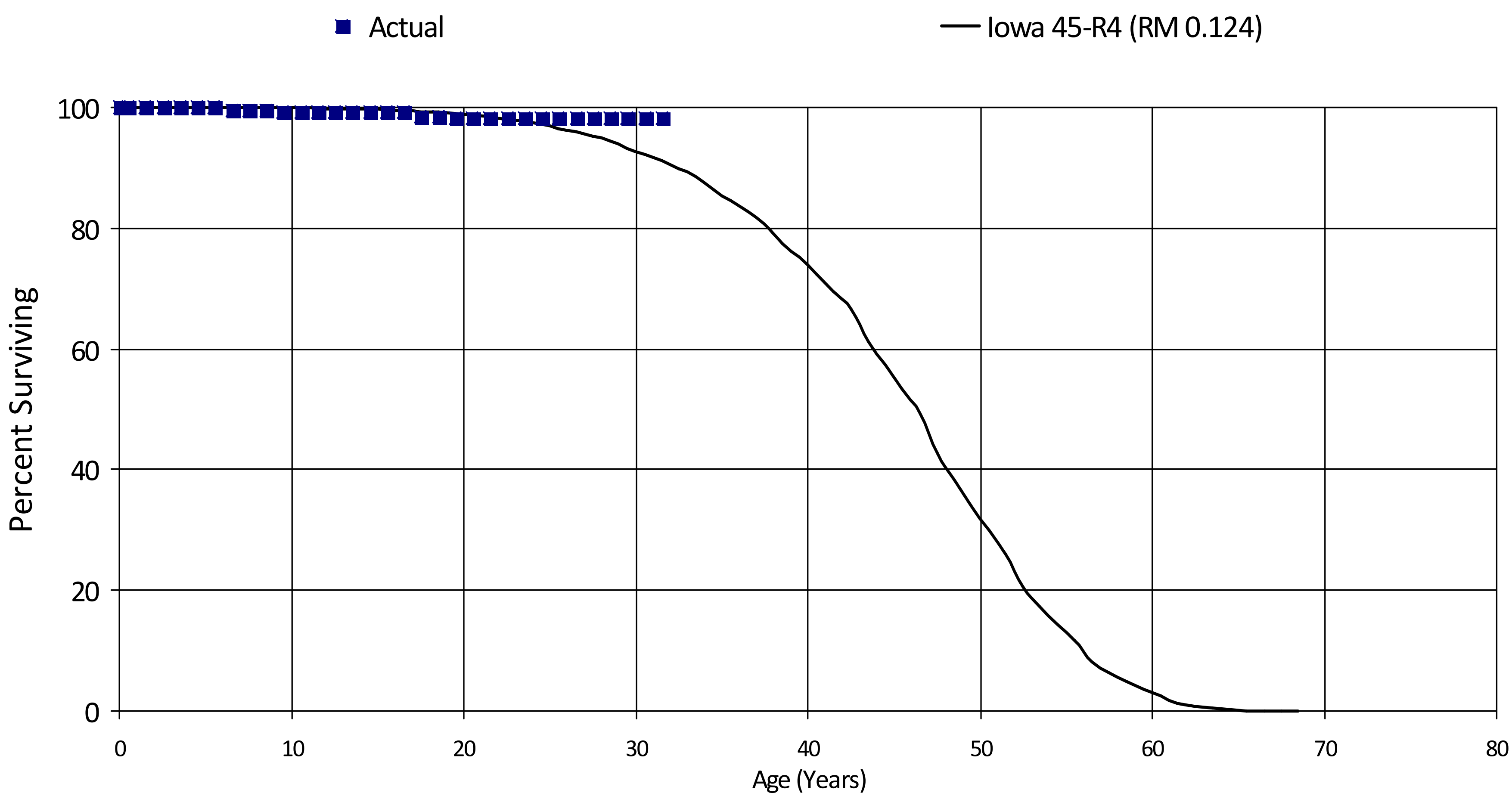
27.5	21,865,922	0	0.00000	1.00000	97.22
28.5	21,865,922	0	0.00000	1.00000	97.22
29.5	21,778,327	0	0.00000	1.00000	97.22
30.5	21,704,086	0	0.00000	1.00000	97.22
31.5	21,615,169	0	0.00000	1.00000	97.22
32.5	21,569,544	0	0.00000	1.00000	97.22
33.5	21,555,644	0	0.00000	1.00000	97.22
34.5	21,555,644	0	0.00000	1.00000	97.22
35.5	7,329,754	0	0.00000	1.00000	97.22
36.5	7,329,754	0	0.00000	1.00000	97.22
37.5	7,310,772	0	0.00000	1.00000	97.22
38.5	7,310,772	0	0.00000	1.00000	97.22
39.5	5,210,009	0	0.00000	1.00000	97.22
40.5	4,051,667	12,209	0.00301	0.99699	97.22
41.5	4,039,459	0	0.00000	1.00000	96.93
42.5	4,039,459	0	0.00000	1.00000	96.93
43.5	4,039,459	0	0.00000	1.00000	96.93
44.5	4,039,459	0	0.00000	1.00000	96.93
45.5	4,039,459	0	0.00000	1.00000	96.93
46.5	4,039,459	0	0.00000	1.00000	96.93
	Totals:	682,266			

BC Hydro Power Authority

Account 23604 - Gate

Placement Band - 1927 - 2020   Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23604 - Gate

Placement Band - 1927 - 2020   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	388,611,539	0	0.00000	1.00000	100.00
0.5	388,448,502	0	0.00000	1.00000	100.00
1.5	385,730,972	0	0.00000	1.00000	100.00
2.5	365,795,379	0	0.00000	1.00000	100.00
3.5	336,859,626	-709	0.00000	1.00000	100.00
4.5	318,958,075	55	0.00000	1.00000	100.00
5.5	262,477,422	1,024,667	0.00390	0.99610	100.00
6.5	238,471,834	0	0.00000	1.00000	99.61
7.5	198,076,422	0	0.00000	1.00000	99.61
8.5	181,773,739	526,873	0.00290	0.99710	99.61
9.5	174,355,375	213,858	0.00123	0.99877	99.32
10.5	35,111,900	0	0.00000	1.00000	99.20
11.5	34,662,701	0	0.00000	1.00000	99.20
12.5	33,802,806	0	0.00000	1.00000	99.20
13.5	33,777,262	0	0.00000	1.00000	99.20
14.5	32,965,616	0	0.00000	1.00000	99.20
15.5	32,090,004	0	0.00000	1.00000	99.20
16.5	32,065,929	194,961	0.00608	0.99392	99.20
17.5	31,870,968	0	0.00000	1.00000	98.60
18.5	27,335,754	79,300	0.00290	0.99710	98.60
19.5	27,256,454	0	0.00000	1.00000	98.31
20.5	24,920,373	0	0.00000	1.00000	98.31
21.5	24,920,373	0	0.00000	1.00000	98.31
22.5	24,625,975	0	0.00000	1.00000	98.31
23.5	6,327,636	705	0.00011	0.99989	98.31
24.5	6,127,050	0	0.00000	1.00000	98.30
25.5	6,127,050	0	0.00000	1.00000	98.30
26.5	5,361,860	0	0.00000	1.00000	98.30

BC Hydro Power Authority

Account 23604 - Gate

Placement Band - 1927 - 2020 Experience Band - 2012 - 2020

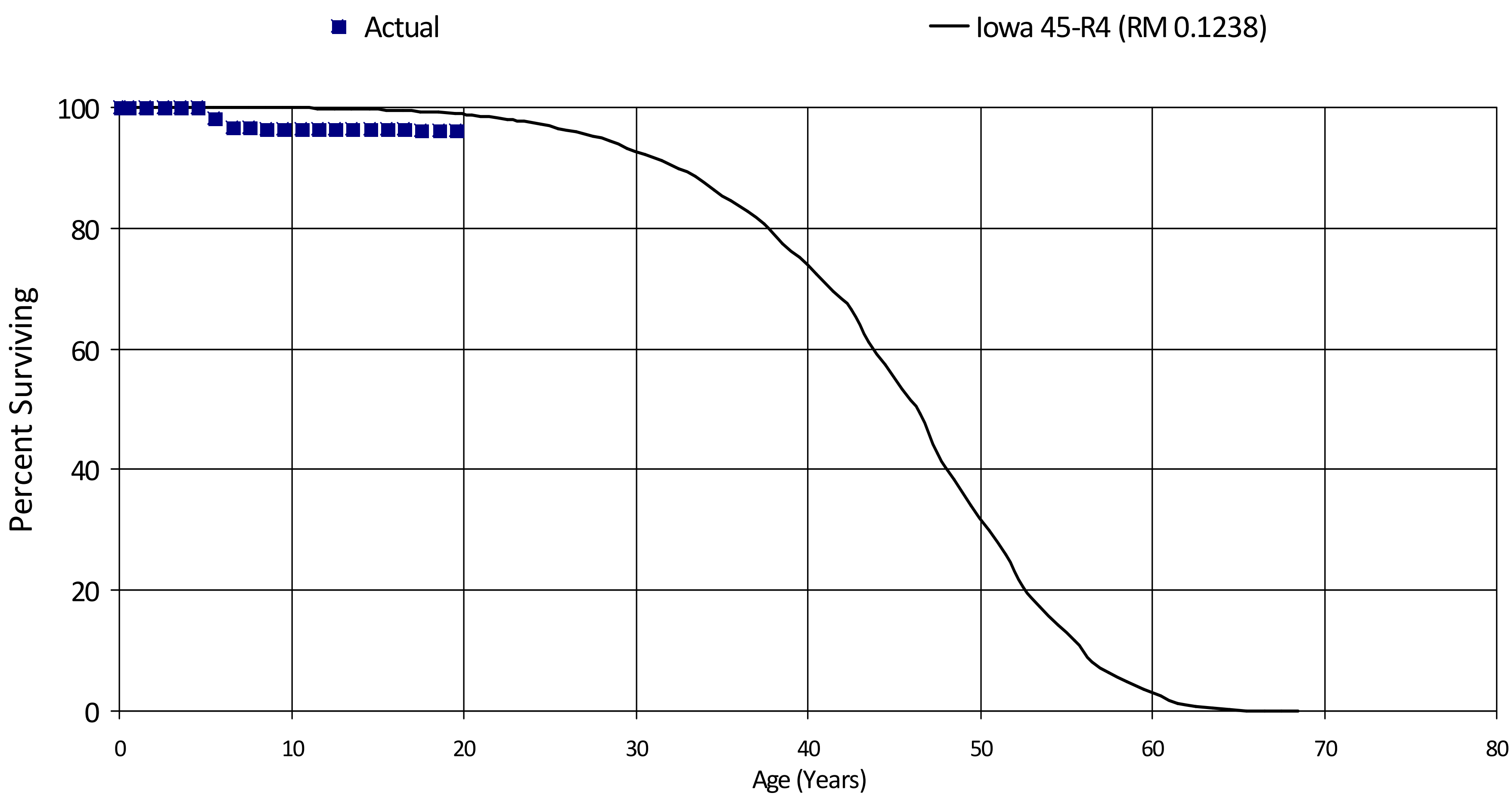
27.5	5,361,860	0	0.00000	1.00000	98.30
28.5	5,111,569	0	0.00000	1.00000	98.30
29.5	4,646,386	0	0.00000	1.00000	98.30
30.5	4,404,957	0	0.00000	1.00000	98.30
31.5	4,361,663	1,515,518	0.34746	0.65254	98.30
	Totals:	3,555,228			

BC Hydro Power Authority

Account 23605 - Gates, Embedded Components

Placement Band - 1999 - 2018   Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23605 - Gates, Embedded Components

Placement Band - 1999 - 2018   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

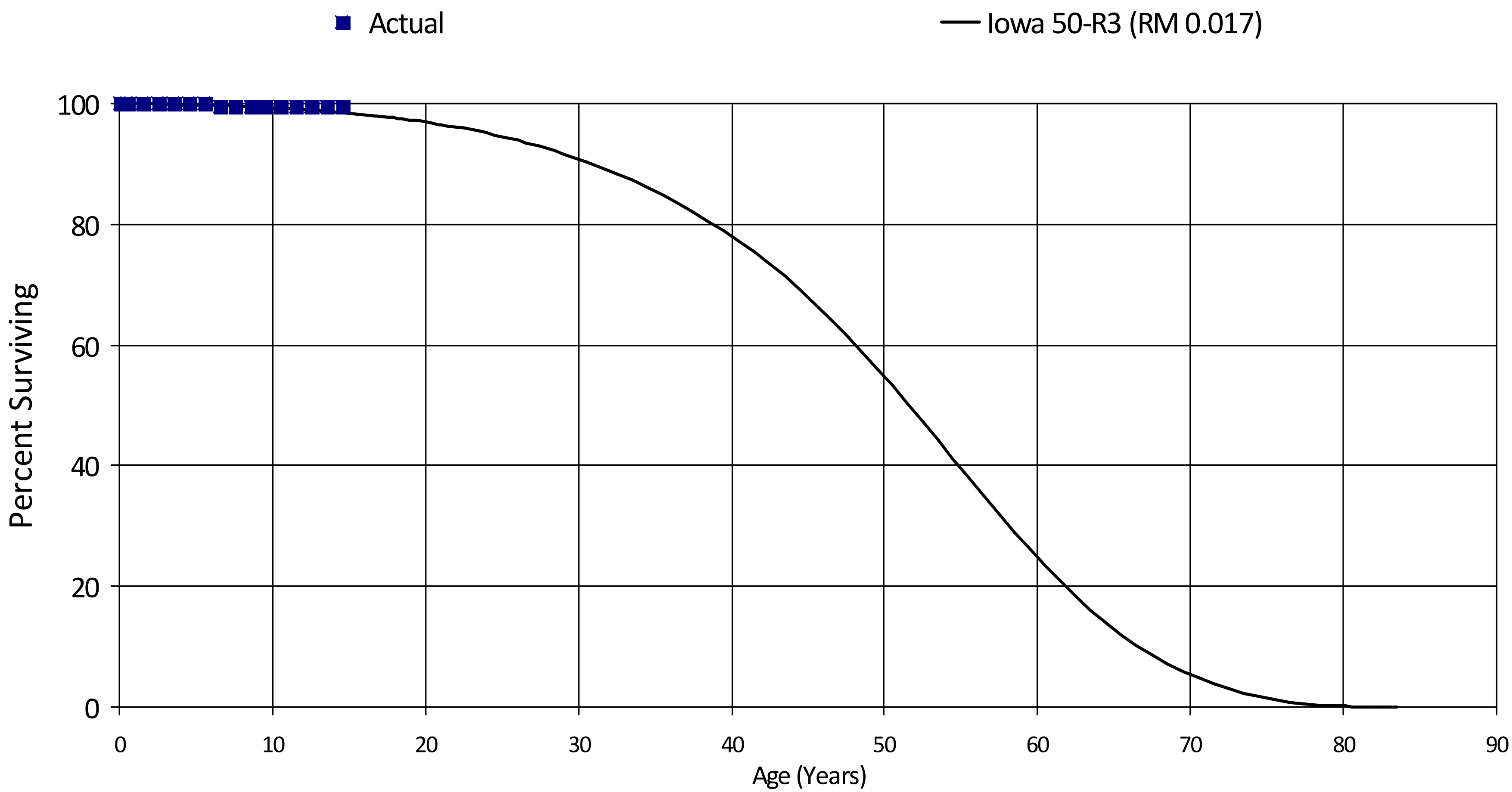
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	41,994,804	0	0.00000	1.00000	100.00
0.5	41,994,804	0	0.00000	1.00000	100.00
1.5	41,994,804	0	0.00000	1.00000	100.00
2.5	41,890,737	0	0.00000	1.00000	100.00
3.5	41,890,737	0	0.00000	1.00000	100.00
4.5	41,890,737	776,390	0.01853	0.98147	100.00
5.5	41,114,346	606,784	0.01476	0.98524	98.15
6.5	40,507,563	39,838	0.00098	0.99902	96.70
7.5	36,759,780	79,676	0.00217	0.99783	96.61
8.5	28,181,735	0	0.00000	1.00000	96.40
9.5	20,115,975	0	0.00000	1.00000	96.40
10.5	20,115,975	0	0.00000	1.00000	96.40
11.5	20,115,975	0	0.00000	1.00000	96.40
12.5	20,115,975	0	0.00000	1.00000	96.40
13.5	7,116,293	0	0.00000	1.00000	96.40
14.5	6,754,880	0	0.00000	1.00000	96.40
15.5	1,356,608	0	0.00000	1.00000	96.40
16.5	1,267,189	3,452	0.00272	0.99728	96.40
17.5	1,263,737	0	0.00000	1.00000	96.14
18.5	1,199,846	0	0.00000	1.00000	96.14
19.5	1,199,846	0	0.00000	1.00000	96.14
	Totals:	1,506,140			

BC Hydro Power Authority

Account 23606 - Inlet Valves, Penstock & Turbines

Placement Band - 2001 - 2018 Experience Band - 2015 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23606 - Inlet Valves, Penstock & Turbines

Placement Band - 2001 - 2018   Experience Band - 2015 - 2020

RETIREMENT RATE ANALYSIS

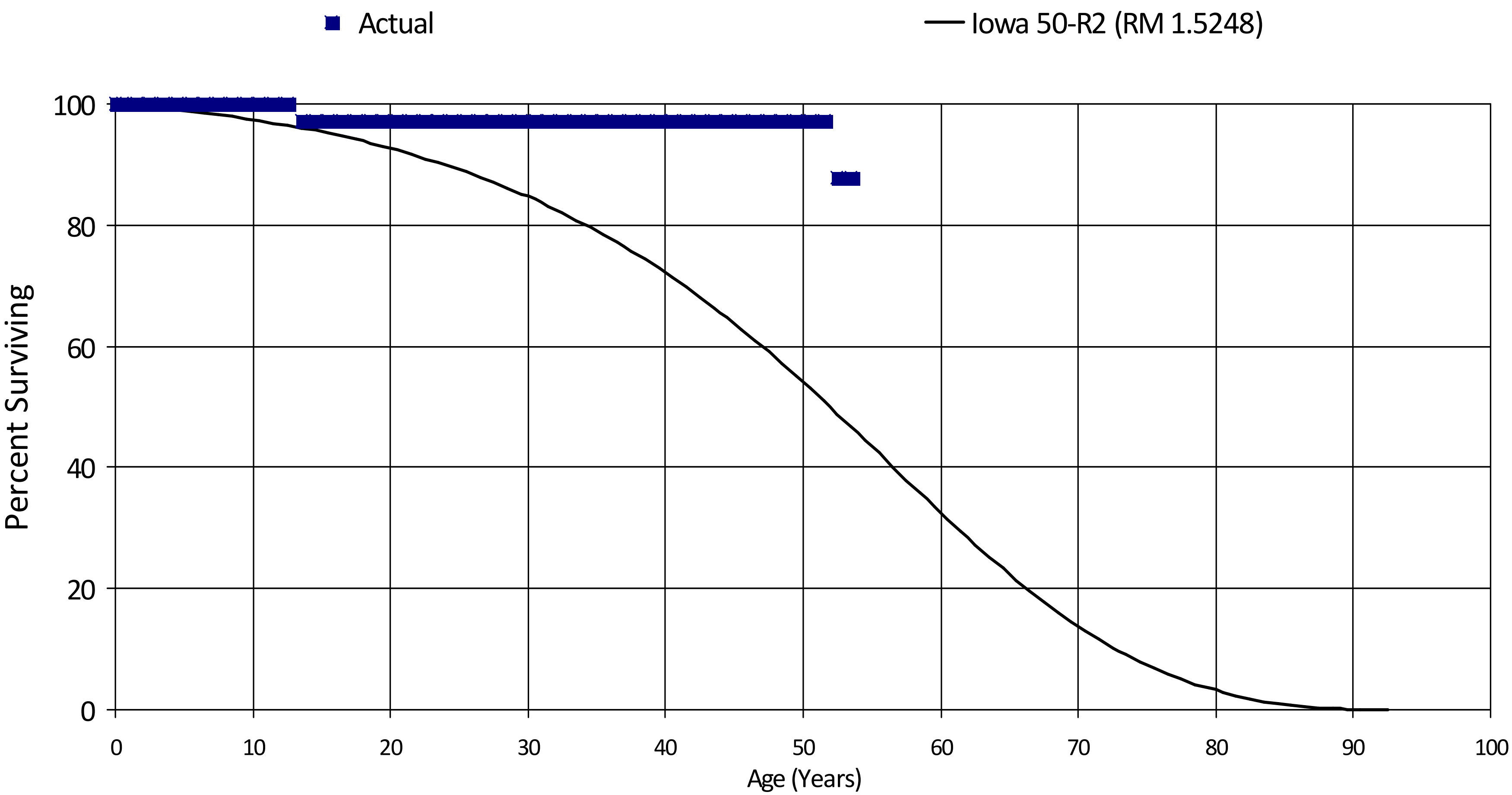
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	26,249,075	0	0.00000	1.00000	100.00
0.5	26,249,075	0	0.00000	1.00000	100.00
1.5	26,249,075	0	0.00000	1.00000	100.00
2.5	5,830,355	0	0.00000	1.00000	100.00
3.5	5,830,355	0	0.00000	1.00000	100.00
4.5	4,249,379	0	0.00000	1.00000	100.00
5.5	4,249,379	17,546	0.00413	0.99587	100.00
6.5	4,210,757	0	0.00000	1.00000	99.59
7.5	4,210,757	0	0.00000	1.00000	99.59
8.5	4,210,757	0	0.00000	1.00000	99.59
9.5	4,110,860	0	0.00000	1.00000	99.59
10.5	4,110,860	0	0.00000	1.00000	99.59
11.5	3,137,930	0	0.00000	1.00000	99.59
12.5	1,735,884	0	0.00000	1.00000	99.59
13.5	1,735,884	0	0.00000	1.00000	99.59
14.5	1,735,884	0	0.00000	1.00000	99.59
	Totals:	17,546			

BC Hydro Power Authority

Account 23701 - Trash Racks

Placement Band - 1929 - 2018   Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23701 - Trash Racks

Placement Band - 1929 - 2018   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	15,801,229	0	0.00000	1.00000	100.00
0.5	15,801,229	0	0.00000	1.00000	100.00
1.5	15,801,229	0	0.00000	1.00000	100.00
2.5	11,974,193	0	0.00000	1.00000	100.00
3.5	11,095,326	0	0.00000	1.00000	100.00
4.5	8,933,356	0	0.00000	1.00000	100.00
5.5	8,933,356	0	0.00000	1.00000	100.00
6.5	8,933,356	0	0.00000	1.00000	100.00
7.5	8,933,356	0	0.00000	1.00000	100.00
8.5	8,897,538	0	0.00000	1.00000	100.00
9.5	8,406,481	0	0.00000	1.00000	100.00
10.5	6,104,008	0	0.00000	1.00000	100.00
11.5	6,104,008	0	0.00000	1.00000	100.00
12.5	4,818,346	136,554	0.02834	0.97166	100.00
13.5	4,410,128	0	0.00000	1.00000	97.17
14.5	4,410,128	0	0.00000	1.00000	97.17
15.5	4,410,128	0	0.00000	1.00000	97.17
16.5	4,092,146	0	0.00000	1.00000	97.17
17.5	4,092,146	0	0.00000	1.00000	97.17
18.5	4,092,146	0	0.00000	1.00000	97.17
19.5	4,089,992	0	0.00000	1.00000	97.17
20.5	3,890,217	0	0.00000	1.00000	97.17
21.5	3,890,217	0	0.00000	1.00000	97.17
22.5	3,890,217	0	0.00000	1.00000	97.17
23.5	3,890,217	0	0.00000	1.00000	97.17
24.5	3,856,743	0	0.00000	1.00000	97.17
25.5	3,841,652	0	0.00000	1.00000	97.17
26.5	3,841,652	0	0.00000	1.00000	97.17

BC Hydro Power Authority

Account 23701 - Trash Racks

Placement Band - 1929 - 2018 Experience Band - 2012 - 2020

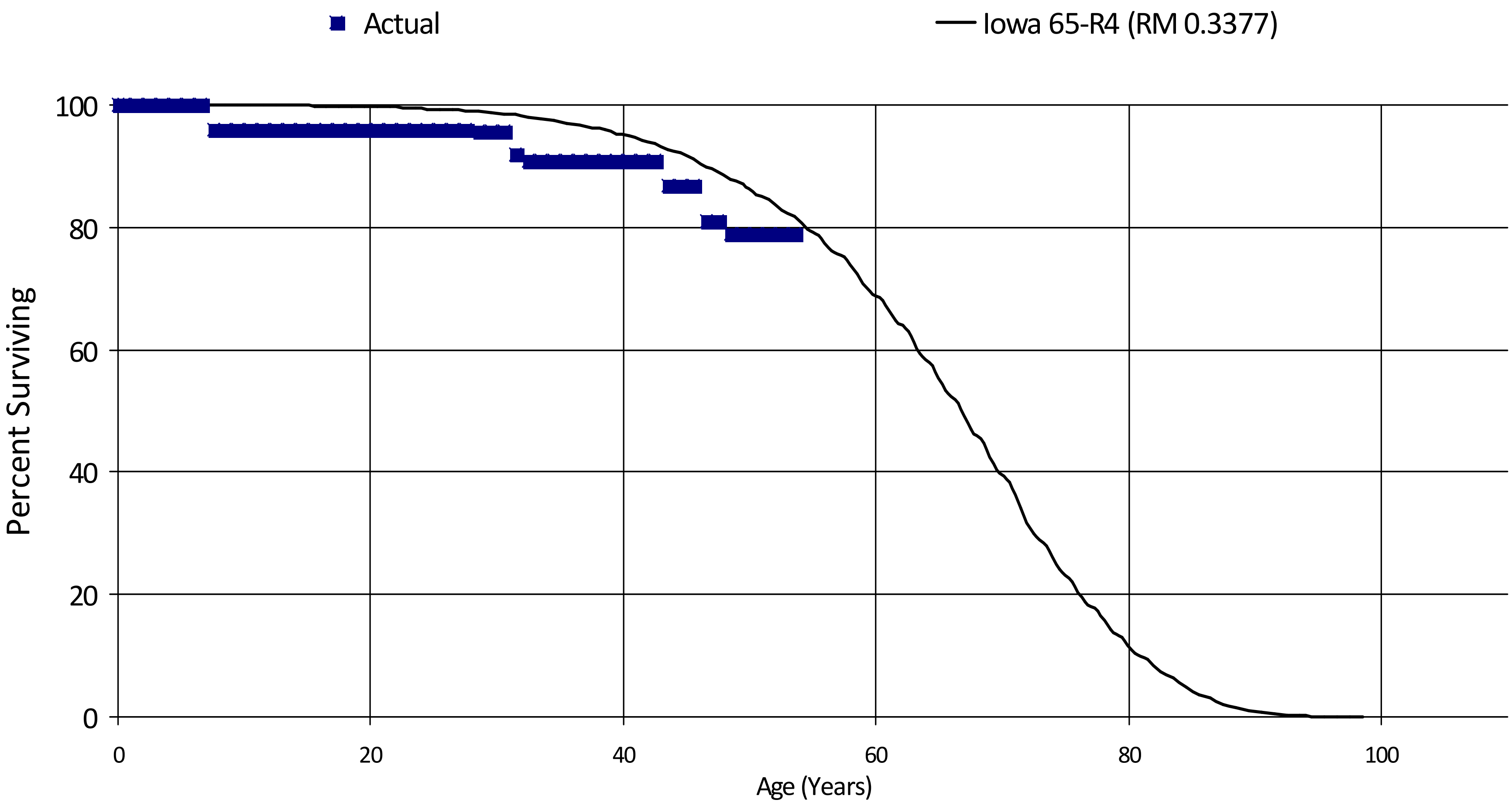
27.5	3,841,652	0	0.00000	1.00000	97.17
28.5	3,806,608	0	0.00000	1.00000	97.17
29.5	3,806,608	0	0.00000	1.00000	97.17
30.5	3,806,608	0	0.00000	1.00000	97.17
31.5	3,806,608	0	0.00000	1.00000	97.17
32.5	3,806,608	0	0.00000	1.00000	97.17
33.5	3,806,608	0	0.00000	1.00000	97.17
34.5	3,806,608	0	0.00000	1.00000	97.17
35.5	1,141,334	0	0.00000	1.00000	97.17
36.5	1,141,334	0	0.00000	1.00000	97.17
37.5	1,141,334	0	0.00000	1.00000	97.17
38.5	1,141,334	0	0.00000	1.00000	97.17
39.5	783,641	0	0.00000	1.00000	97.17
40.5	783,641	0	0.00000	1.00000	97.17
41.5	501,206	0	0.00000	1.00000	97.17
42.5	501,206	0	0.00000	1.00000	97.17
43.5	501,206	0	0.00000	1.00000	97.17
44.5	501,206	0	0.00000	1.00000	97.17
45.5	501,206	0	0.00000	1.00000	97.17
46.5	501,206	0	0.00000	1.00000	97.17
47.5	476,635	0	0.00000	1.00000	97.17
48.5	476,244	0	0.00000	1.00000	97.17
49.5	476,244	0	0.00000	1.00000	97.17
50.5	435,708	0	0.00000	1.00000	97.17
51.5	435,708	42,373	0.09725	0.90275	97.17
52.5	393,335	0	0.00000	1.00000	87.72
53.5	393,335	0	0.00000	1.00000	87.72
	Totals:	178,927			

BC Hydro Power Authority

Account 23801 - Cranes

Placement Band - 1902 - 2019   Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23801 - Cranes

Placement Band - 1902 - 2019 Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	121,311,355	0	0.00000	1.00000	100.00
0.5	121,311,355	0	0.00000	1.00000	100.00
1.5	79,197,374	0	0.00000	1.00000	100.00
2.5	70,859,216	0	0.00000	1.00000	100.00
3.5	69,791,473	0	0.00000	1.00000	100.00
4.5	68,653,240	0	0.00000	1.00000	100.00
5.5	67,802,591	0	0.00000	1.00000	100.00
6.5	61,115,573	2,428,255	0.03973	0.96027	100.00
7.5	57,082,540	0	0.00000	1.00000	96.03
8.5	51,401,058	0	0.00000	1.00000	96.03
9.5	48,858,204	0	0.00000	1.00000	96.03
10.5	36,014,157	4,427	0.00012	0.99988	96.03
11.5	35,985,952	0	0.00000	1.00000	96.02
12.5	35,572,610	0	0.00000	1.00000	96.02
13.5	35,522,636	0	0.00000	1.00000	96.02
14.5	35,231,414	0	0.00000	1.00000	96.02
15.5	33,876,571	40,518	0.00120	0.99880	96.02
16.5	33,550,018	0	0.00000	1.00000	95.90
17.5	31,274,456	0	0.00000	1.00000	95.90
18.5	31,274,456	0	0.00000	1.00000	95.90
19.5	31,274,456	0	0.00000	1.00000	95.90
20.5	28,177,675	0	0.00000	1.00000	95.90
21.5	28,177,675	0	0.00000	1.00000	95.90
22.5	28,177,675	0	0.00000	1.00000	95.90
23.5	28,175,672	5,098	0.00018	0.99982	95.90
24.5	28,104,850	0	0.00000	1.00000	95.88
25.5	28,104,850	0	0.00000	1.00000	95.88
26.5	28,092,744	0	0.00000	1.00000	95.88

BC Hydro Power Authority

Account 23801 - Cranes

Placement Band - 1902 - 2019 Experience Band - 2012 - 2020

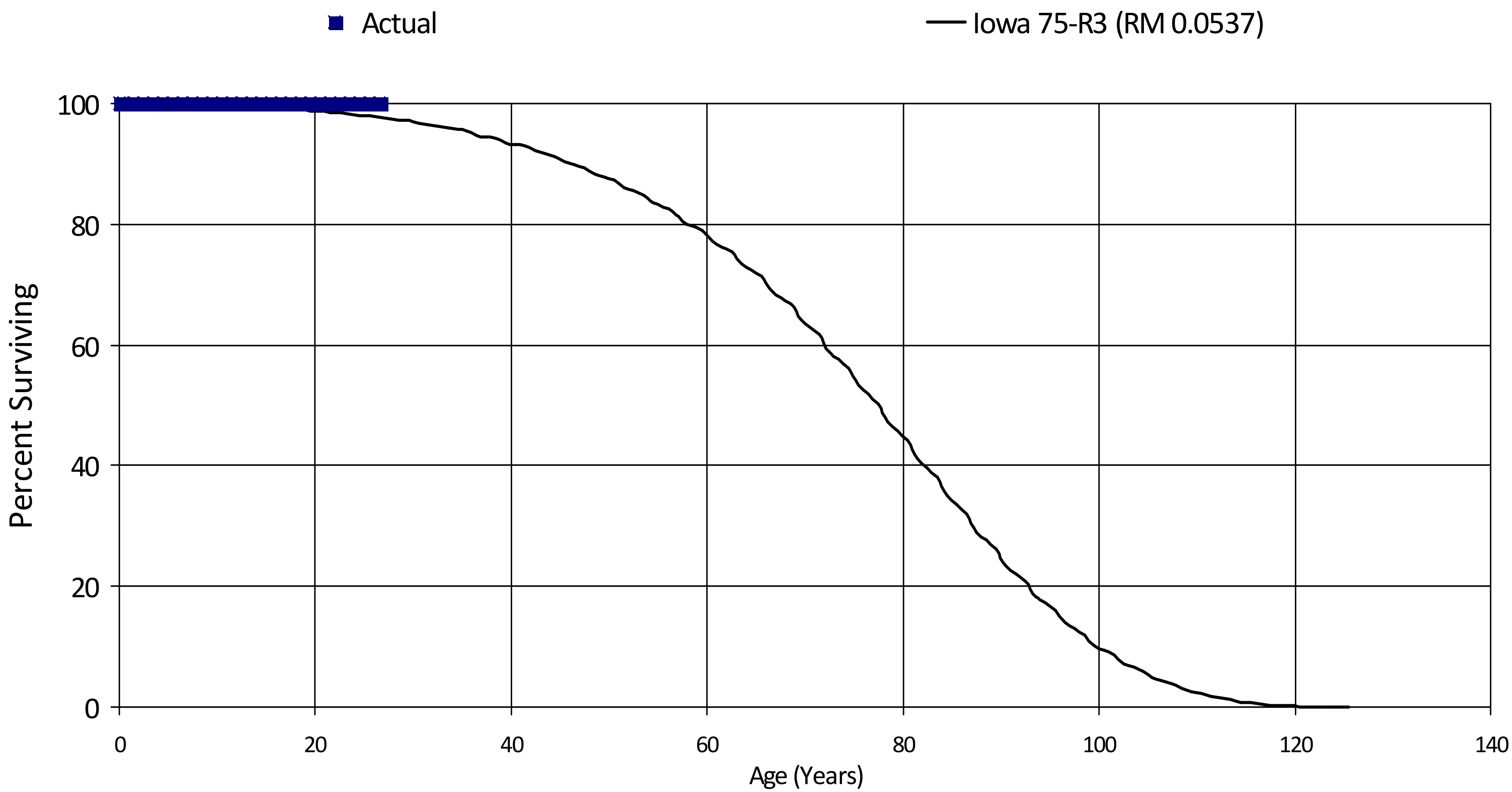
27.5	28,085,211	45,572	0.00162	0.99838	95.88
28.5	28,024,017	0	0.00000	1.00000	95.72
29.5	28,024,017	0	0.00000	1.00000	95.72
30.5	28,015,484	1,106,214	0.03949	0.96051	95.72
31.5	26,909,269	308,776	0.01147	0.98853	91.94
32.5	26,600,493	0	0.00000	1.00000	90.89
33.5	26,600,493	0	0.00000	1.00000	90.89
34.5	26,600,493	0	0.00000	1.00000	90.89
35.5	19,017,339	0	0.00000	1.00000	90.89
36.5	19,016,185	0	0.00000	1.00000	90.89
37.5	18,986,802	0	0.00000	1.00000	90.89
38.5	18,977,554	0	0.00000	1.00000	90.89
39.5	15,096,271	0	0.00000	1.00000	90.89
40.5	13,565,690	0	0.00000	1.00000	90.89
41.5	13,565,690	0	0.00000	1.00000	90.89
42.5	13,546,542	604,275	0.04461	0.95539	90.89
43.5	12,932,146	0	0.00000	1.00000	86.84
44.5	11,994,726	0	0.00000	1.00000	86.84
45.5	9,758,969	654,389	0.06706	0.93294	86.84
46.5	9,101,665	0	0.00000	1.00000	81.02
47.5	7,554,309	185,878	0.02461	0.97539	81.02
48.5	7,189,863	0	0.00000	1.00000	79.03
49.5	7,189,863	0	0.00000	1.00000	79.03
50.5	7,038,886	0	0.00000	1.00000	79.03
51.5	3,139,220	0	0.00000	1.00000	79.03
52.5	3,139,220	4,258	0.00136	0.99864	79.03
53.5	3,117,028	0	0.00000	1.00000	78.92
	Totals:	5,387,660			

BC Hydro Power Authority

Account 23901 - Fishways, Steel

Placement Band - 1965 - 2008 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23901 - Fishways, Steel

Placement Band - 1965 - 2008 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	6,196,252	0	0.00000	1.00000	100.00
0.5	6,196,252	0	0.00000	1.00000	100.00
1.5	6,196,252	0	0.00000	1.00000	100.00
2.5	6,196,252	0	0.00000	1.00000	100.00
3.5	6,196,252	0	0.00000	1.00000	100.00
4.5	6,196,252	0	0.00000	1.00000	100.00
5.5	6,196,252	0	0.00000	1.00000	100.00
6.5	6,196,252	0	0.00000	1.00000	100.00
7.5	6,196,252	0	0.00000	1.00000	100.00
8.5	6,196,252	0	0.00000	1.00000	100.00
9.5	6,196,252	0	0.00000	1.00000	100.00
10.5	6,196,252	0	0.00000	1.00000	100.00
11.5	6,196,252	0	0.00000	1.00000	100.00
12.5	6,108,274	0	0.00000	1.00000	100.00
13.5	2,965,208	0	0.00000	1.00000	100.00
14.5	2,945,822	0	0.00000	1.00000	100.00
15.5	2,945,822	0	0.00000	1.00000	100.00
16.5	2,945,822	0	0.00000	1.00000	100.00
17.5	2,945,822	0	0.00000	1.00000	100.00
18.5	2,945,822	0	0.00000	1.00000	100.00
19.5	2,945,822	0	0.00000	1.00000	100.00
20.5	2,945,822	0	0.00000	1.00000	100.00
21.5	2,945,822	0	0.00000	1.00000	100.00
22.5	2,945,822	0	0.00000	1.00000	100.00
23.5	2,945,822	0	0.00000	1.00000	100.00
24.5	2,900,711	0	0.00000	1.00000	100.00
25.5	2,900,711	0	0.00000	1.00000	100.00
26.5	2,900,711	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 23901 - Fishways, Steel

Placement Band - 1965 - 2008   Experience Band - 2020 - 2020

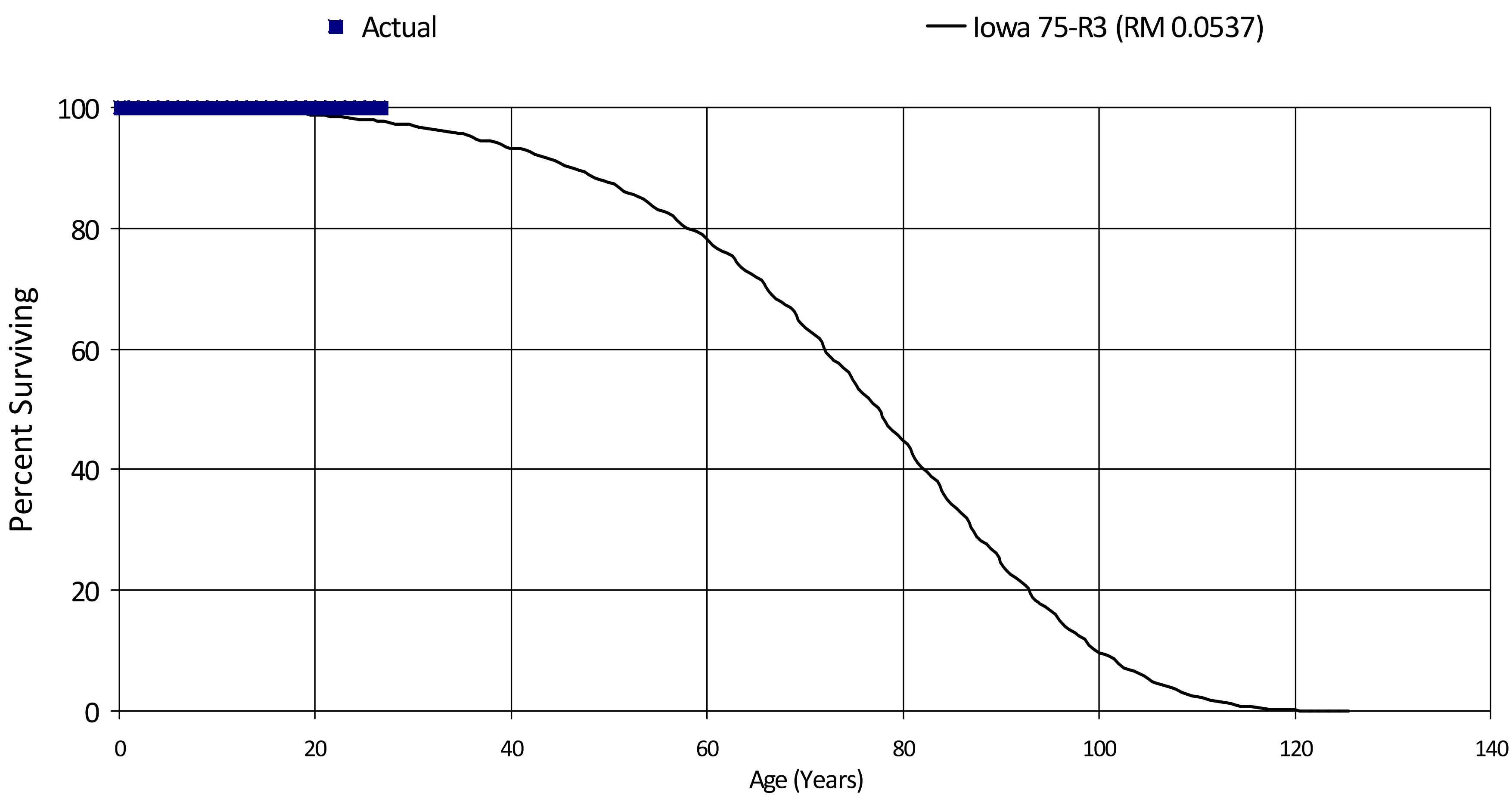
Totals:	0

BC Hydro Power Authority

Account 23902 - Fishways, Concrete

Placement Band - 1993 - 2006   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 23902 - Fishways, Concrete

Placement Band - 1993 - 2006   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	251,228	0	0.00000	1.00000	100.00
0.5	251,228	0	0.00000	1.00000	100.00
1.5	251,228	0	0.00000	1.00000	100.00
2.5	251,228	0	0.00000	1.00000	100.00
3.5	251,228	0	0.00000	1.00000	100.00
4.5	251,228	0	0.00000	1.00000	100.00
5.5	251,228	0	0.00000	1.00000	100.00
6.5	251,228	0	0.00000	1.00000	100.00
7.5	251,228	0	0.00000	1.00000	100.00
8.5	251,228	0	0.00000	1.00000	100.00
9.5	251,228	0	0.00000	1.00000	100.00
10.5	251,228	0	0.00000	1.00000	100.00
11.5	251,228	0	0.00000	1.00000	100.00
12.5	251,228	0	0.00000	1.00000	100.00
13.5	251,228	0	0.00000	1.00000	100.00
14.5	89,159	0	0.00000	1.00000	100.00
15.5	89,159	0	0.00000	1.00000	100.00
16.5	89,159	0	0.00000	1.00000	100.00
17.5	88,607	0	0.00000	1.00000	100.00
18.5	88,607	0	0.00000	1.00000	100.00
19.5	88,607	0	0.00000	1.00000	100.00
20.5	88,607	0	0.00000	1.00000	100.00
21.5	88,607	0	0.00000	1.00000	100.00
22.5	88,607	0	0.00000	1.00000	100.00
23.5	88,607	0	0.00000	1.00000	100.00
24.5	88,607	0	0.00000	1.00000	100.00
25.5	88,607	0	0.00000	1.00000	100.00
26.5	19,913	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 23902 - Fishways, Concrete

Placement Band - 1993 - 2006   Experience Band - 2020 - 2020

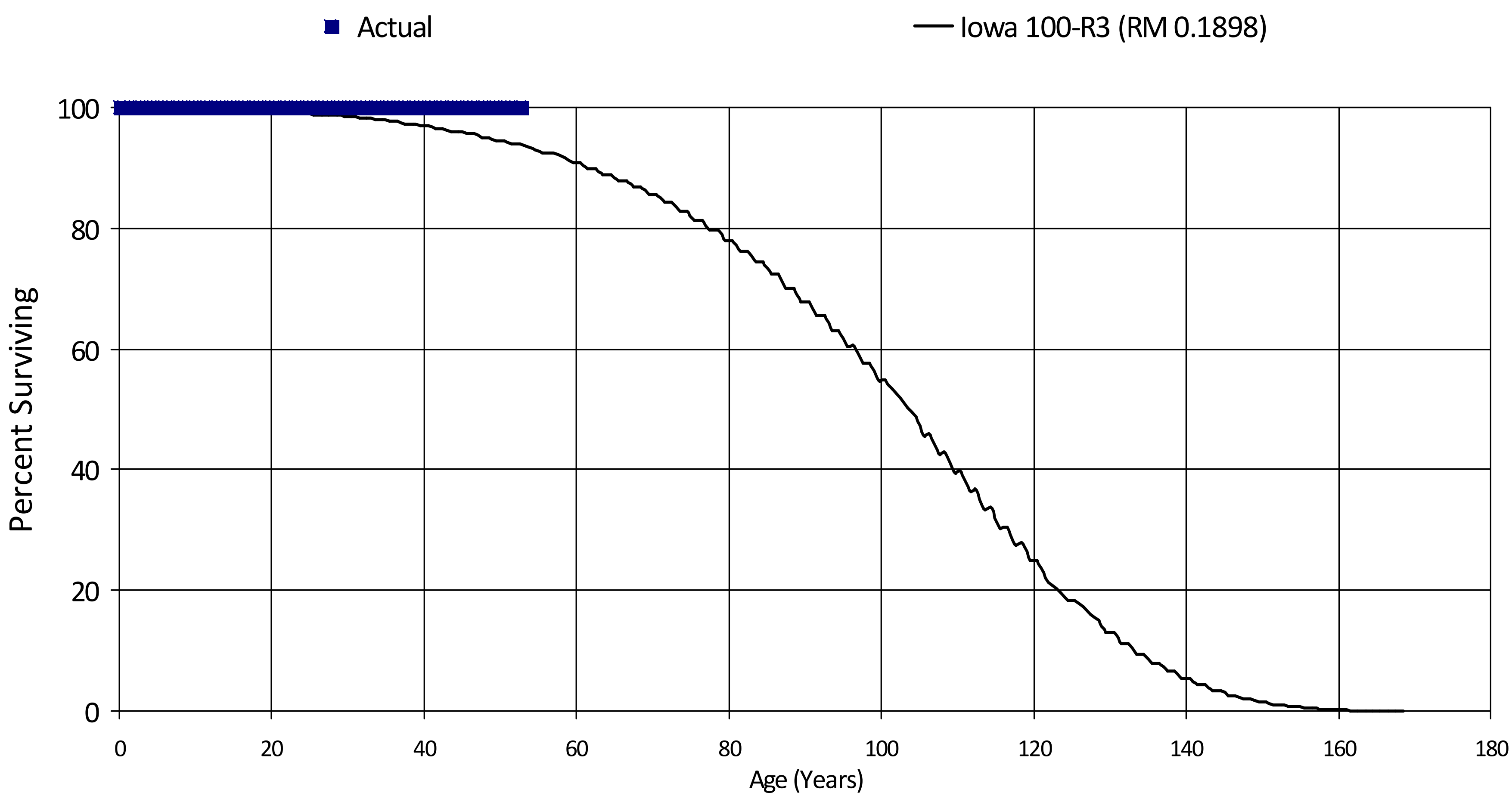
Totals: 0

BC Hydro Power Authority

Account 24001 - Navigation Locks

Placement Band - 1967 - 2013   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 24001 - Navigation Locks

Placement Band - 1967 - 2013   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	25,782,700	0	0.00000	1.00000	100.00
0.5	25,782,700	0	0.00000	1.00000	100.00
1.5	25,782,700	0	0.00000	1.00000	100.00
2.5	25,782,700	0	0.00000	1.00000	100.00
3.5	25,782,700	0	0.00000	1.00000	100.00
4.5	25,782,700	0	0.00000	1.00000	100.00
5.5	25,782,700	0	0.00000	1.00000	100.00
6.5	25,782,700	0	0.00000	1.00000	100.00
7.5	24,428,250	0	0.00000	1.00000	100.00
8.5	24,428,250	0	0.00000	1.00000	100.00
9.5	24,428,250	0	0.00000	1.00000	100.00
10.5	24,428,250	0	0.00000	1.00000	100.00
11.5	24,428,250	0	0.00000	1.00000	100.00
12.5	24,428,250	0	0.00000	1.00000	100.00
13.5	24,428,250	0	0.00000	1.00000	100.00
14.5	24,428,250	0	0.00000	1.00000	100.00
15.5	24,428,250	0	0.00000	1.00000	100.00
16.5	24,428,250	0	0.00000	1.00000	100.00
17.5	24,100,072	0	0.00000	1.00000	100.00
18.5	24,100,072	0	0.00000	1.00000	100.00
19.5	24,100,072	0	0.00000	1.00000	100.00
20.5	24,100,072	0	0.00000	1.00000	100.00
21.5	24,100,072	0	0.00000	1.00000	100.00
22.5	24,100,072	0	0.00000	1.00000	100.00
23.5	24,100,072	0	0.00000	1.00000	100.00
24.5	24,100,072	0	0.00000	1.00000	100.00
25.5	24,100,072	0	0.00000	1.00000	100.00
26.5	24,100,072	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 24001 - Navigation Locks

Placement Band - 1967 - 2013 Experience Band - 2020 - 2020

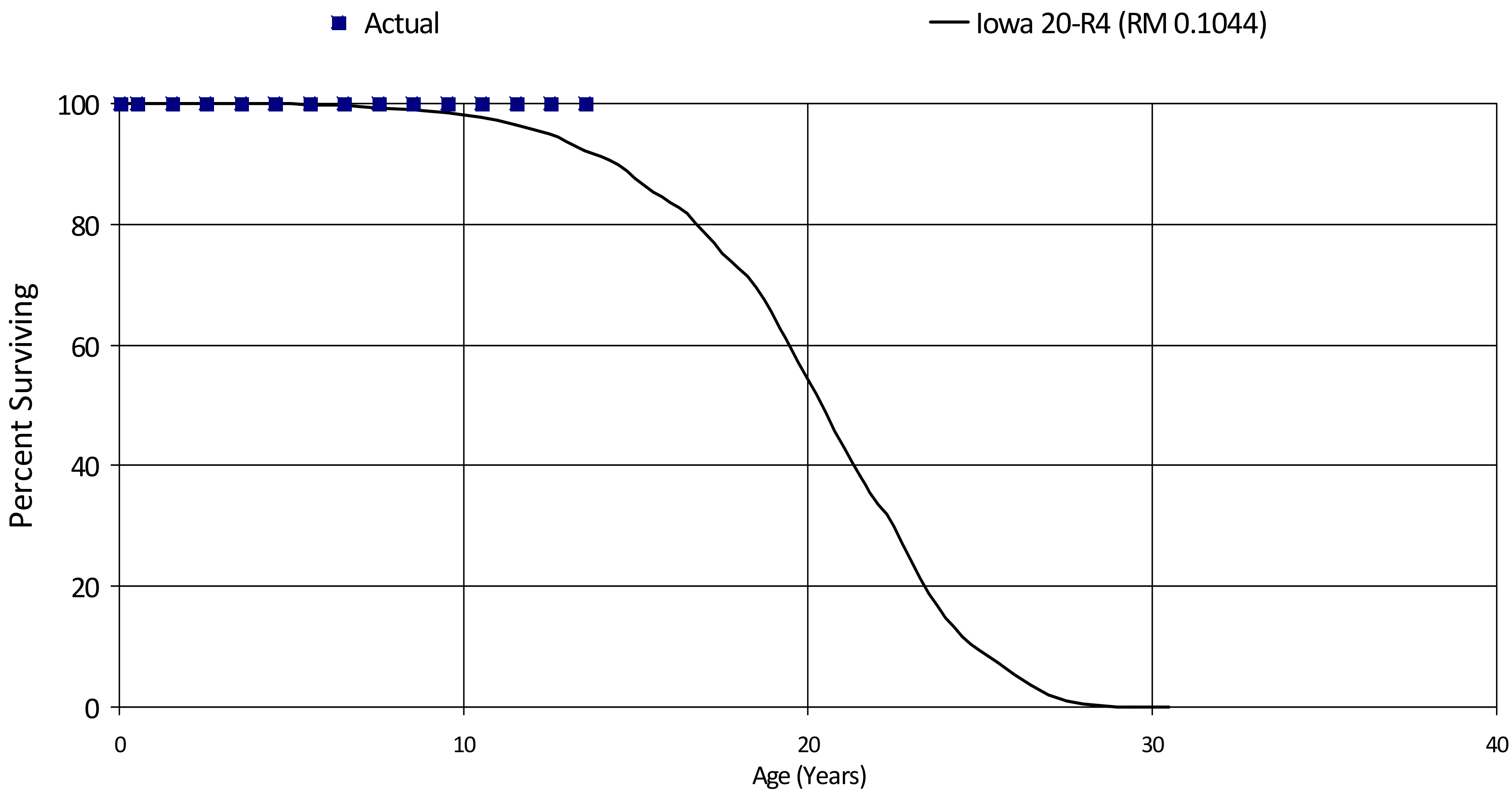
27.5	24,100,072	0	0.00000	1.00000	100.00
28.5	24,100,072	0	0.00000	1.00000	100.00
29.5	24,100,072	0	0.00000	1.00000	100.00
30.5	24,100,072	0	0.00000	1.00000	100.00
31.5	24,100,072	0	0.00000	1.00000	100.00
32.5	24,100,072	0	0.00000	1.00000	100.00
33.5	24,100,072	0	0.00000	1.00000	100.00
34.5	24,100,072	0	0.00000	1.00000	100.00
35.5	24,100,072	0	0.00000	1.00000	100.00
36.5	24,100,072	0	0.00000	1.00000	100.00
37.5	24,100,072	0	0.00000	1.00000	100.00
38.5	24,100,072	0	0.00000	1.00000	100.00
39.5	24,100,072	0	0.00000	1.00000	100.00
40.5	24,100,072	0	0.00000	1.00000	100.00
41.5	24,100,072	0	0.00000	1.00000	100.00
42.5	24,100,072	0	0.00000	1.00000	100.00
43.5	2,579,810	0	0.00000	1.00000	100.00
44.5	2,579,810	0	0.00000	1.00000	100.00
45.5	2,579,810	0	0.00000	1.00000	100.00
46.5	2,579,810	0	0.00000	1.00000	100.00
47.5	2,579,810	0	0.00000	1.00000	100.00
48.5	2,579,810	0	0.00000	1.00000	100.00
49.5	2,579,810	0	0.00000	1.00000	100.00
50.5	2,579,810	0	0.00000	1.00000	100.00
51.5	1,017,822	0	0.00000	1.00000	100.00
52.5	1,017,822	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 24002 - Controls

Placement Band - 2000 - 2019   Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 24002 - Controls

Placement Band - 2000 - 2019   Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

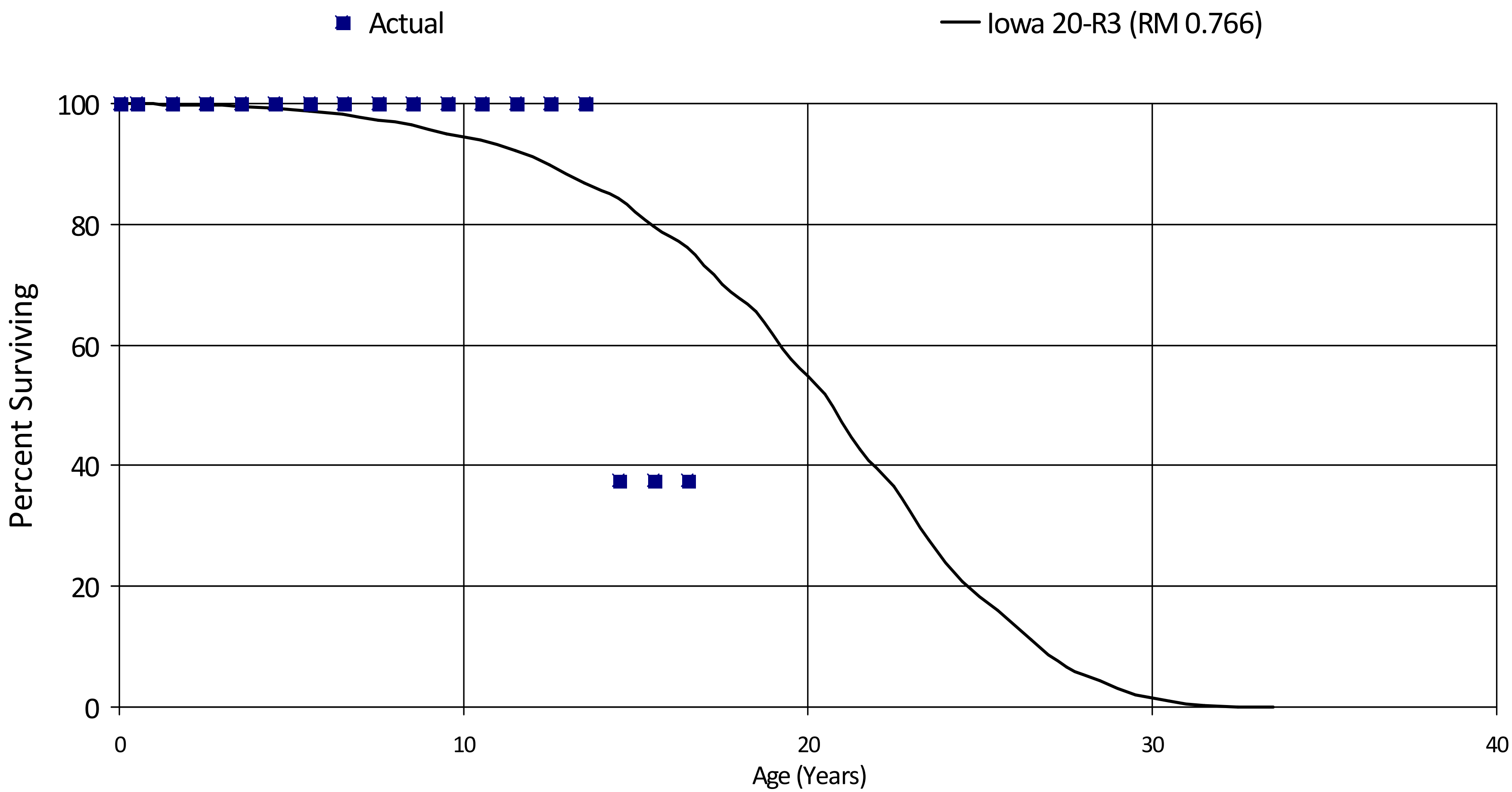
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	9,444,919	0	0.00000	1.00000	100.00
0.5	9,444,919	0	0.00000	1.00000	100.00
1.5	6,873,463	0	0.00000	1.00000	100.00
2.5	6,873,463	0	0.00000	1.00000	100.00
3.5	6,873,463	0	0.00000	1.00000	100.00
4.5	6,801,169	0	0.00000	1.00000	100.00
5.5	6,801,169	0	0.00000	1.00000	100.00
6.5	6,801,169	0	0.00000	1.00000	100.00
7.5	991,497	0	0.00000	1.00000	100.00
8.5	991,497	0	0.00000	1.00000	100.00
9.5	991,497	0	0.00000	1.00000	100.00
10.5	991,497	0	0.00000	1.00000	100.00
11.5	991,497	0	0.00000	1.00000	100.00
12.5	991,497	0	0.00000	1.00000	100.00
13.5	991,497	991,497	1.00000		100.00
	Totals:	991,497			

BC Hydro Power Authority

Account 24003 - Motor

Placement Band - 1977 - 2003 Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 24003 - Motor

Placement Band - 1977 - 2003   Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

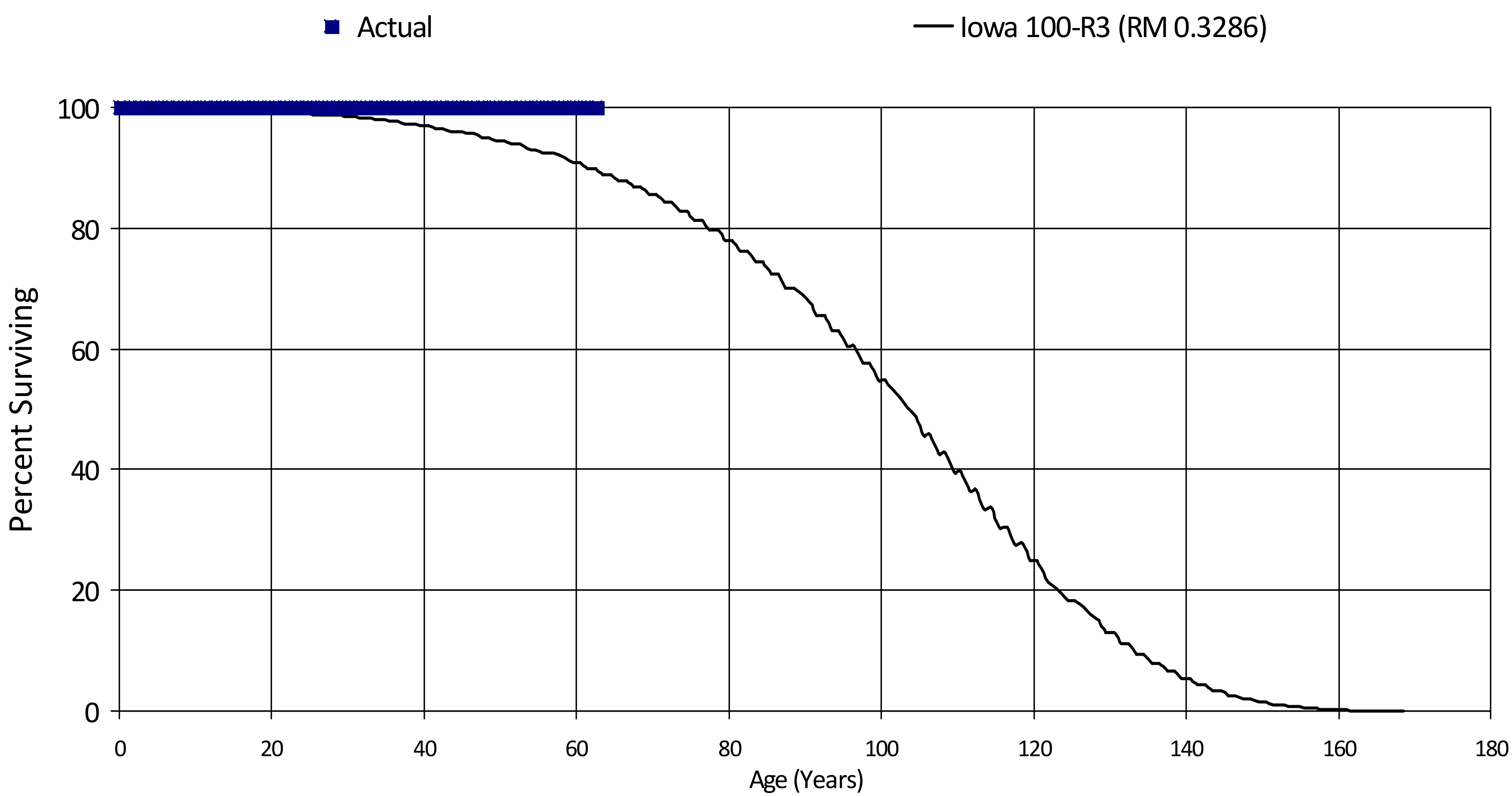
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	72,115	0	0.00000	1.00000	100.00
0.5	72,115	0	0.00000	1.00000	100.00
1.5	72,115	0	0.00000	1.00000	100.00
2.5	72,115	0	0.00000	1.00000	100.00
3.5	72,115	0	0.00000	1.00000	100.00
4.5	72,115	0	0.00000	1.00000	100.00
5.5	72,115	0	0.00000	1.00000	100.00
6.5	72,115	0	0.00000	1.00000	100.00
7.5	72,115	0	0.00000	1.00000	100.00
8.5	72,115	0	0.00000	1.00000	100.00
9.5	72,115	0	0.00000	1.00000	100.00
10.5	72,115	0	0.00000	1.00000	100.00
11.5	72,115	0	0.00000	1.00000	100.00
12.5	72,115	0	0.00000	1.00000	100.00
13.5	72,115	45,000	0.62401	0.37599	100.00
14.5	27,114	0	0.00000	1.00000	37.60
15.5	27,114	0	0.00000	1.00000	37.60
16.5	27,114	0	0.00000	1.00000	37.60
	Totals:	45,000			

BC Hydro Power Authority

Account 24101 - Sluiceway, Separate From Dam

Placement Band - 1931 - 2010 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 24101 - Sluiceway, Separate From Dam

Placement Band - 1931 - 2010   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	37,493,964	0	0.00000	1.00000	100.00
0.5	37,493,964	0	0.00000	1.00000	100.00
1.5	37,493,964	0	0.00000	1.00000	100.00
2.5	37,493,964	0	0.00000	1.00000	100.00
3.5	37,493,964	0	0.00000	1.00000	100.00
4.5	37,493,964	0	0.00000	1.00000	100.00
5.5	37,493,964	0	0.00000	1.00000	100.00
6.5	37,493,964	0	0.00000	1.00000	100.00
7.5	37,493,964	0	0.00000	1.00000	100.00
8.5	37,493,964	0	0.00000	1.00000	100.00
9.5	37,493,964	0	0.00000	1.00000	100.00
10.5	37,023,144	0	0.00000	1.00000	100.00
11.5	37,023,144	0	0.00000	1.00000	100.00
12.5	37,023,144	0	0.00000	1.00000	100.00
13.5	37,023,144	0	0.00000	1.00000	100.00
14.5	35,493,186	0	0.00000	1.00000	100.00
15.5	35,493,186	0	0.00000	1.00000	100.00
16.5	35,493,186	0	0.00000	1.00000	100.00
17.5	35,493,186	0	0.00000	1.00000	100.00
18.5	35,493,186	0	0.00000	1.00000	100.00
19.5	35,493,186	0	0.00000	1.00000	100.00
20.5	35,493,186	0	0.00000	1.00000	100.00
21.5	35,493,186	0	0.00000	1.00000	100.00
22.5	35,493,186	0	0.00000	1.00000	100.00
23.5	35,493,186	0	0.00000	1.00000	100.00
24.5	35,493,186	0	0.00000	1.00000	100.00
25.5	35,493,186	0	0.00000	1.00000	100.00
26.5	35,493,186	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 24101 - Sluiceway, Separate From Dam

Placement Band - 1931 - 2010 Experience Band - 2020 - 2020

27.5	35,493,186	0	0.00000	1.00000	100.00
28.5	35,493,186	0	0.00000	1.00000	100.00
29.5	35,370,955	0	0.00000	1.00000	100.00
30.5	35,370,955	0	0.00000	1.00000	100.00
31.5	35,370,955	0	0.00000	1.00000	100.00
32.5	35,370,955	0	0.00000	1.00000	100.00
33.5	35,370,955	0	0.00000	1.00000	100.00
34.5	35,370,955	0	0.00000	1.00000	100.00
35.5	35,370,955	0	0.00000	1.00000	100.00
36.5	35,370,955	0	0.00000	1.00000	100.00
37.5	35,370,955	0	0.00000	1.00000	100.00
38.5	35,366,634	0	0.00000	1.00000	100.00
39.5	35,366,634	0	0.00000	1.00000	100.00
40.5	35,366,634	0	0.00000	1.00000	100.00
41.5	35,366,634	0	0.00000	1.00000	100.00
42.5	35,366,634	0	0.00000	1.00000	100.00
43.5	33,884,161	0	0.00000	1.00000	100.00
44.5	33,874,325	0	0.00000	1.00000	100.00
45.5	33,874,325	0	0.00000	1.00000	100.00
46.5	33,874,325	0	0.00000	1.00000	100.00
47.5	33,874,325	0	0.00000	1.00000	100.00
48.5	33,874,325	0	0.00000	1.00000	100.00
49.5	33,874,325	0	0.00000	1.00000	100.00
50.5	33,874,325	0	0.00000	1.00000	100.00
51.5	8,895,142	0	0.00000	1.00000	100.00
52.5	8,895,142	0	0.00000	1.00000	100.00
53.5	8,895,142	0	0.00000	1.00000	100.00
54.5	8,269,129	0	0.00000	1.00000	100.00
55.5	8,243,004	0	0.00000	1.00000	100.00
56.5	6,752,539	0	0.00000	1.00000	100.00
57.5	6,752,539	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 24101 - Sluiceway, Separate From Dam

Placement Band - 1931 - 2010   Experience Band - 2020 - 2020

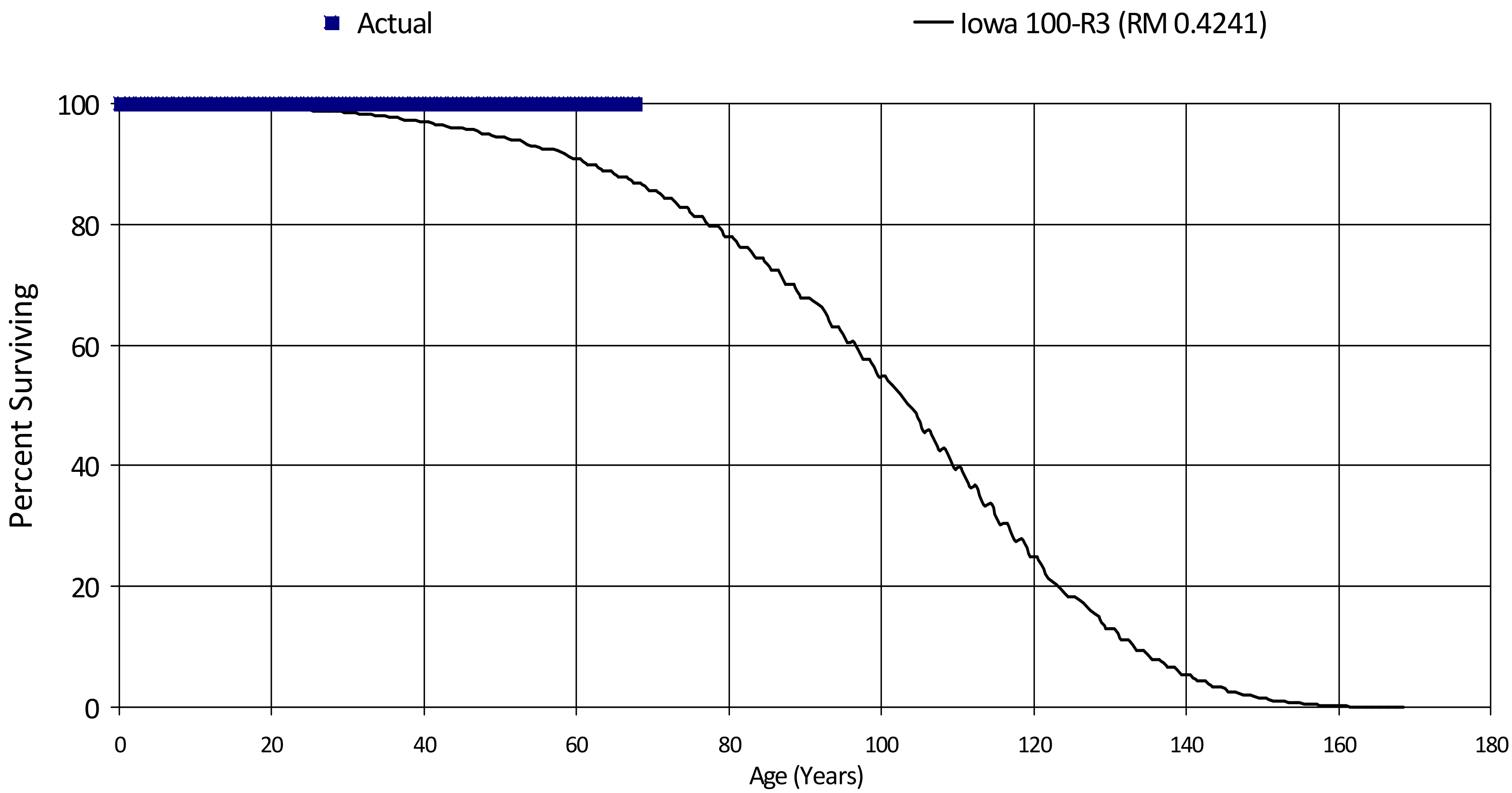
58.5	6,752,539	0	0.00000	1.00000	100.00
59.5	6,752,539	0	0.00000	1.00000	100.00
60.5	1,729,436	0	0.00000	1.00000	100.00
61.5	1,702,454	0	0.00000	1.00000	100.00
62.5	1,328,838	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 24201 - Tunnels

Placement Band - 1929 - 2012 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 24201 - Tunnels

Placement Band - 1929 - 2012 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	65,348,911	0	0.00000	1.00000	100.00
0.5	65,348,911	0	0.00000	1.00000	100.00
1.5	65,348,911	0	0.00000	1.00000	100.00
2.5	65,348,911	0	0.00000	1.00000	100.00
3.5	65,348,911	0	0.00000	1.00000	100.00
4.5	65,348,911	0	0.00000	1.00000	100.00
5.5	65,348,911	0	0.00000	1.00000	100.00
6.5	65,348,911	0	0.00000	1.00000	100.00
7.5	65,348,911	0	0.00000	1.00000	100.00
8.5	52,348,858	0	0.00000	1.00000	100.00
9.5	52,348,858	0	0.00000	1.00000	100.00
10.5	51,020,693	0	0.00000	1.00000	100.00
11.5	51,020,693	0	0.00000	1.00000	100.00
12.5	49,541,073	0	0.00000	1.00000	100.00
13.5	49,541,073	0	0.00000	1.00000	100.00
14.5	48,620,689	0	0.00000	1.00000	100.00
15.5	48,620,689	0	0.00000	1.00000	100.00
16.5	48,620,689	0	0.00000	1.00000	100.00
17.5	48,620,689	0	0.00000	1.00000	100.00
18.5	48,620,689	0	0.00000	1.00000	100.00
19.5	48,620,689	0	0.00000	1.00000	100.00
20.5	41,676,672	0	0.00000	1.00000	100.00
21.5	41,676,672	0	0.00000	1.00000	100.00
22.5	41,676,672	0	0.00000	1.00000	100.00
23.5	41,676,672	0	0.00000	1.00000	100.00
24.5	41,676,672	0	0.00000	1.00000	100.00
25.5	40,257,960	0	0.00000	1.00000	100.00
26.5	40,257,960	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 24201 - Tunnels

Placement Band - 1929 - 2012   Experience Band - 2020 - 2020

27.5	38,403,481	0	0.00000	1.00000	100.00
28.5	37,784,349	0	0.00000	1.00000	100.00
29.5	37,587,831	0	0.00000	1.00000	100.00
30.5	37,587,831	0	0.00000	1.00000	100.00
31.5	37,587,831	0	0.00000	1.00000	100.00
32.5	37,587,831	0	0.00000	1.00000	100.00
33.5	37,587,831	0	0.00000	1.00000	100.00
34.5	37,587,831	0	0.00000	1.00000	100.00
35.5	37,587,831	0	0.00000	1.00000	100.00
36.5	37,587,831	0	0.00000	1.00000	100.00
37.5	37,587,831	0	0.00000	1.00000	100.00
38.5	37,587,831	0	0.00000	1.00000	100.00
39.5	37,032,402	0	0.00000	1.00000	100.00
40.5	37,032,402	0	0.00000	1.00000	100.00
41.5	37,032,402	0	0.00000	1.00000	100.00
42.5	37,032,402	0	0.00000	1.00000	100.00
43.5	37,002,190	0	0.00000	1.00000	100.00
44.5	37,002,190	0	0.00000	1.00000	100.00
45.5	37,002,190	0	0.00000	1.00000	100.00
46.5	37,002,190	0	0.00000	1.00000	100.00
47.5	23,999,788	0	0.00000	1.00000	100.00
48.5	23,945,500	0	0.00000	1.00000	100.00
49.5	23,945,500	0	0.00000	1.00000	100.00
50.5	22,845,873	0	0.00000	1.00000	100.00
51.5	19,293,280	0	0.00000	1.00000	100.00
52.5	19,293,280	0	0.00000	1.00000	100.00
53.5	19,293,280	0	0.00000	1.00000	100.00
54.5	19,062,885	0	0.00000	1.00000	100.00
55.5	3,168,988	0	0.00000	1.00000	100.00
56.5	3,168,988	0	0.00000	1.00000	100.00
57.5	3,168,988	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 24201 - Tunnels

Placement Band - 1929 - 2012 Experience Band - 2020 - 2020

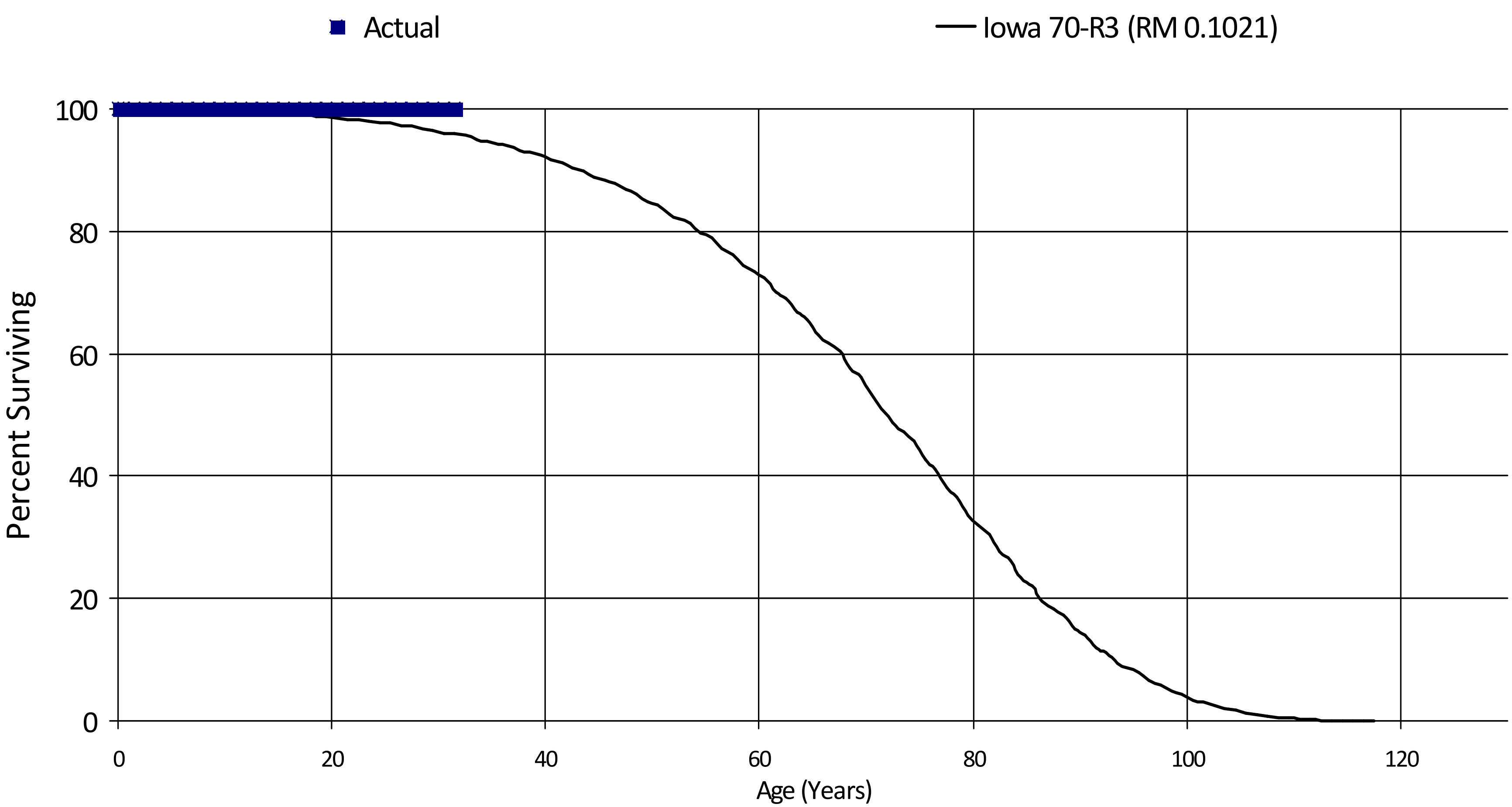
58.5	3,168,988	0	0.00000	1.00000	100.00
59.5	3,168,988	0	0.00000	1.00000	100.00
60.5	3,168,988	0	0.00000	1.00000	100.00
61.5	2,165,544	0	0.00000	1.00000	100.00
62.5	2,165,544	0	0.00000	1.00000	100.00
63.5	2,165,544	0	0.00000	1.00000	100.00
64.5	2,165,544	0	0.00000	1.00000	100.00
65.5	2,165,544	0	0.00000	1.00000	100.00
66.5	2,165,544	0	0.00000	1.00000	100.00
67.5	2,165,544	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 24301 - Slope Stabilization

Placement Band - 1949 - 2018   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 24301 - Slope Stabilization

Placement Band - 1949 - 2018   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	163,190,840	0	0.00000	1.00000	100.00
0.5	163,190,840	0	0.00000	1.00000	100.00
1.5	163,190,840	0	0.00000	1.00000	100.00
2.5	161,544,111	0	0.00000	1.00000	100.00
3.5	32,502,143	0	0.00000	1.00000	100.00
4.5	30,306,387	0	0.00000	1.00000	100.00
5.5	30,306,387	0	0.00000	1.00000	100.00
6.5	29,571,002	0	0.00000	1.00000	100.00
7.5	29,301,098	0	0.00000	1.00000	100.00
8.5	25,094,882	0	0.00000	1.00000	100.00
9.5	24,830,017	0	0.00000	1.00000	100.00
10.5	24,830,017	0	0.00000	1.00000	100.00
11.5	24,787,336	0	0.00000	1.00000	100.00
12.5	24,787,336	0	0.00000	1.00000	100.00
13.5	24,685,205	0	0.00000	1.00000	100.00
14.5	24,501,766	0	0.00000	1.00000	100.00
15.5	15,648,361	0	0.00000	1.00000	100.00
16.5	15,461,736	0	0.00000	1.00000	100.00
17.5	13,379,031	0	0.00000	1.00000	100.00
18.5	12,902,079	0	0.00000	1.00000	100.00
19.5	12,508,251	0	0.00000	1.00000	100.00
20.5	9,883,145	0	0.00000	1.00000	100.00
21.5	9,238,608	0	0.00000	1.00000	100.00
22.5	8,774,623	0	0.00000	1.00000	100.00
23.5	8,774,293	0	0.00000	1.00000	100.00
24.5	7,638,741	0	0.00000	1.00000	100.00
25.5	5,936,676	0	0.00000	1.00000	100.00
26.5	3,542,929	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 24301 - Slope Stabilization

Placement Band - 1949 - 2018 Experience Band - 2013 - 2020

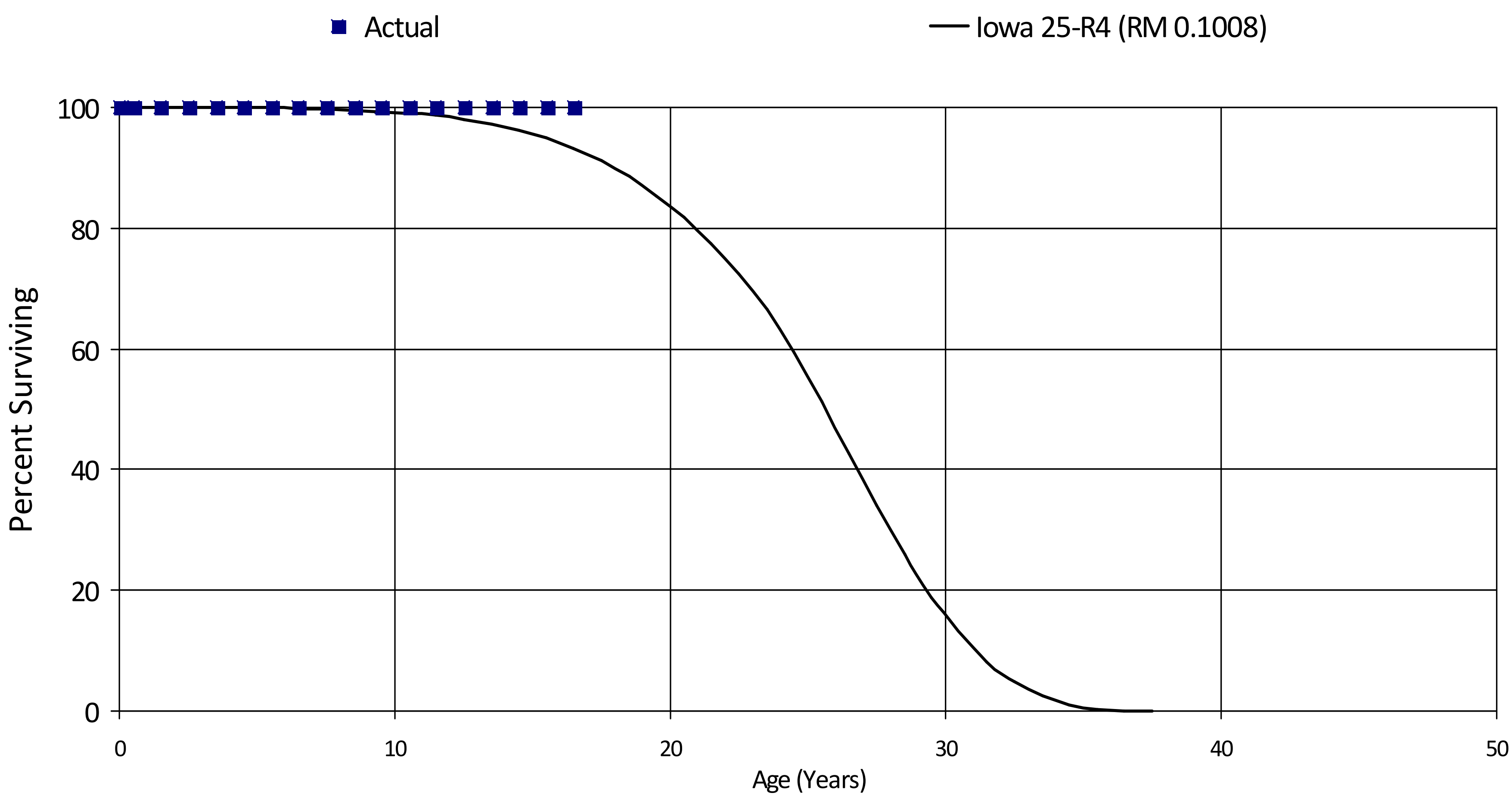
27.5	3,524,431	0	0.00000	1.00000	100.00
28.5	2,657,595	0	0.00000	1.00000	100.00
29.5	2,657,595	0	0.00000	1.00000	100.00
30.5	2,657,595	0	0.00000	1.00000	100.00
31.5	2,657,595	2,503	0.00094	0.99906	100.00
	Totals:	2,503			

BC Hydro Power Authority

Account 24401 - Dock / Wharf

Placement Band - 1990 - 2020 Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 24401 - Dock / Wharf

Placement Band - 1990 - 2020 Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

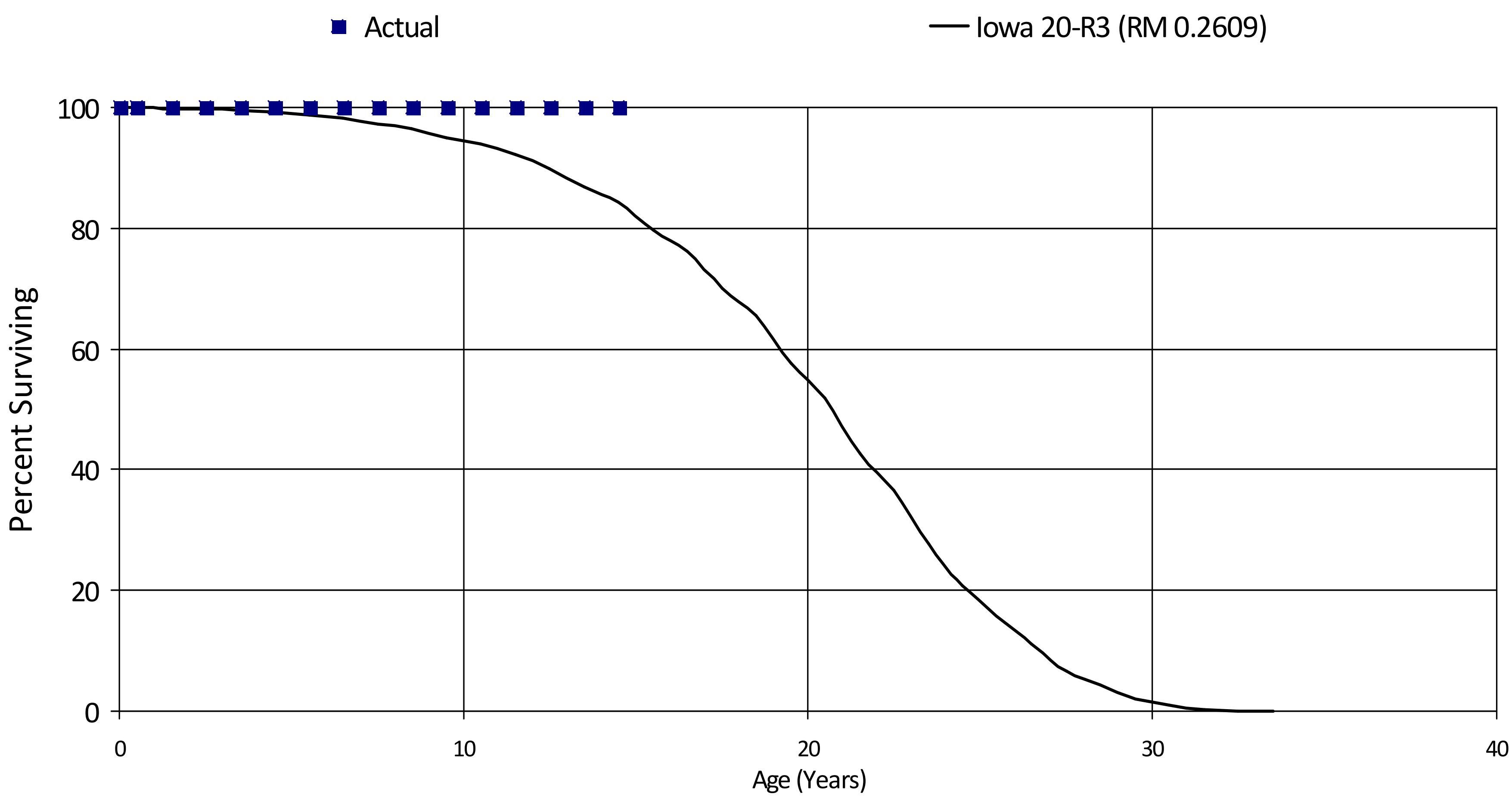
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,736,439	0	0.00000	1.00000	100.00
0.5	962,892	0	0.00000	1.00000	100.00
1.5	962,892	0	0.00000	1.00000	100.00
2.5	956,827	0	0.00000	1.00000	100.00
3.5	569,021	0	0.00000	1.00000	100.00
4.5	569,021	0	0.00000	1.00000	100.00
5.5	554,563	0	0.00000	1.00000	100.00
6.5	503,792	0	0.00000	1.00000	100.00
7.5	503,792	0	0.00000	1.00000	100.00
8.5	503,792	0	0.00000	1.00000	100.00
9.5	503,792	0	0.00000	1.00000	100.00
10.5	503,792	0	0.00000	1.00000	100.00
11.5	503,792	0	0.00000	1.00000	100.00
12.5	503,792	0	0.00000	1.00000	100.00
13.5	503,792	0	0.00000	1.00000	100.00
14.5	503,792	0	0.00000	1.00000	100.00
15.5	113,922	0	0.00000	1.00000	100.00
16.5	33,303	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 24402 - Ramp, Boat / Barge

Placement Band - 1995 - 2016   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 24402 - Ramp, Boat / Barge

Placement Band - 1995 - 2016   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

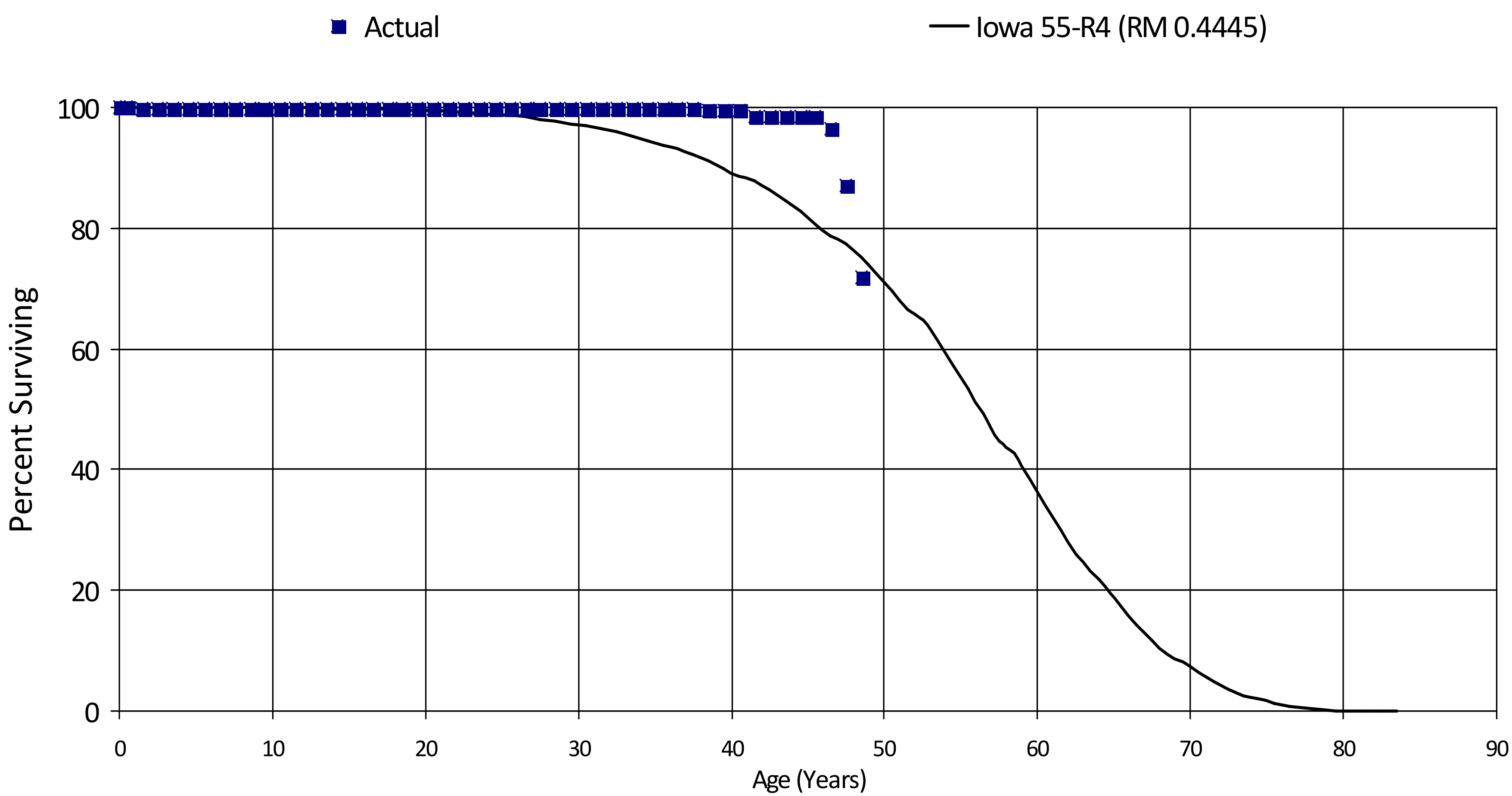
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	6,541,272	0	0.00000	1.00000	100.00
0.5	6,541,272	0	0.00000	1.00000	100.00
1.5	6,541,272	0	0.00000	1.00000	100.00
2.5	6,541,272	0	0.00000	1.00000	100.00
3.5	6,541,272	0	0.00000	1.00000	100.00
4.5	6,258,115	0	0.00000	1.00000	100.00
5.5	1,607,353	0	0.00000	1.00000	100.00
6.5	319,415	0	0.00000	1.00000	100.00
7.5	319,415	0	0.00000	1.00000	100.00
8.5	319,415	0	0.00000	1.00000	100.00
9.5	307,007	0	0.00000	1.00000	100.00
10.5	307,007	0	0.00000	1.00000	100.00
11.5	307,007	0	0.00000	1.00000	100.00
12.5	307,007	0	0.00000	1.00000	100.00
13.5	307,007	0	0.00000	1.00000	100.00
14.5	290,283	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 25101 - Structure, Support, Steel

Placement Band - 1957 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 25101 - Structure, Support, Steel

Placement Band - 1957 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	189,696,271	0	0.00000	1.00000	100.00
0.5	187,495,939	266,442	0.00142	0.99858	100.00
1.5	174,354,579	0	0.00000	1.00000	99.86
2.5	165,375,026	0	0.00000	1.00000	99.86
3.5	152,476,933	0	0.00000	1.00000	99.86
4.5	126,533,029	0	0.00000	1.00000	99.86
5.5	123,016,092	0	0.00000	1.00000	99.86
6.5	117,589,952	0	0.00000	1.00000	99.86
7.5	96,921,763	0	0.00000	1.00000	99.86
8.5	81,907,255	0	0.00000	1.00000	99.86
9.5	67,272,960	0	0.00000	1.00000	99.86
10.5	61,462,484	8,636	0.00014	0.99986	99.86
11.5	55,109,439	0	0.00000	1.00000	99.85
12.5	47,666,984	0	0.00000	1.00000	99.85
13.5	41,244,394	13,857	0.00034	0.99966	99.85
14.5	38,015,709	6,382	0.00017	0.99983	99.82
15.5	34,091,615	0	0.00000	1.00000	99.80
16.5	31,116,215	0	0.00000	1.00000	99.80
17.5	28,709,675	0	0.00000	1.00000	99.80
18.5	27,661,166	13,661	0.00049	0.99951	99.80
19.5	25,899,719	0	0.00000	1.00000	99.75
20.5	24,897,862	0	0.00000	1.00000	99.75
21.5	24,314,625	0	0.00000	1.00000	99.75
22.5	23,358,859	0	0.00000	1.00000	99.75
23.5	22,274,523	0	0.00000	1.00000	99.75
24.5	19,947,059	0	0.00000	1.00000	99.75
25.5	18,650,165	0	0.00000	1.00000	99.75
26.5	17,713,365	0	0.00000	1.00000	99.75

BC Hydro Power Authority

Account 25101 - Structure, Support, Steel

Placement Band - 1957 - 2020   Experience Band - 2013 - 2020

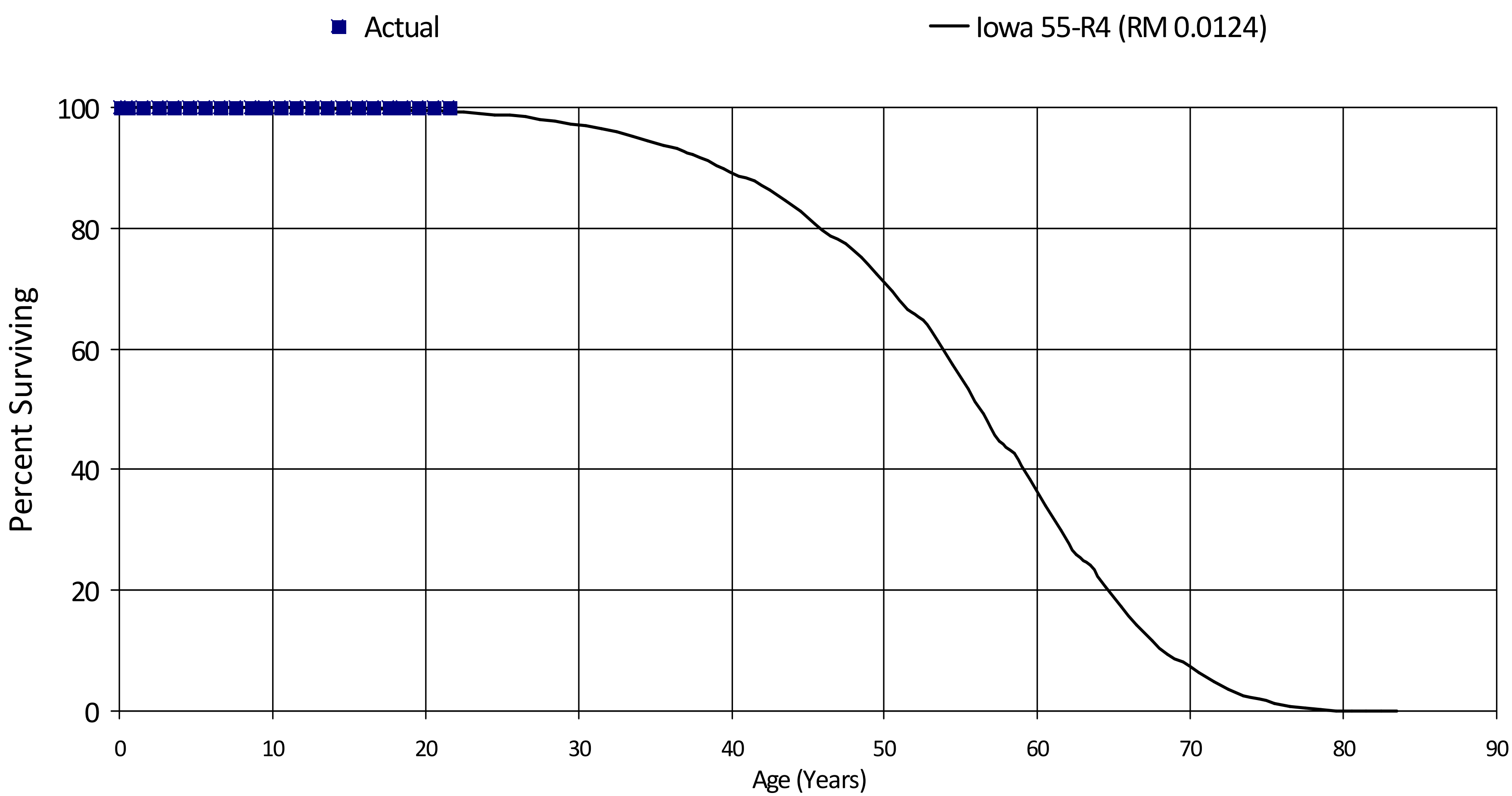
27.5	16,896,344	0	0.00000	1.00000	99.75
28.5	16,328,986	0	0.00000	1.00000	99.75
29.5	14,846,784	0	0.00000	1.00000	99.75
30.5	14,577,500	0	0.00000	1.00000	99.75
31.5	14,356,687	0	0.00000	1.00000	99.75
32.5	13,786,009	0	0.00000	1.00000	99.75
33.5	13,661,662	0	0.00000	1.00000	99.75
34.5	12,948,268	0	0.00000	1.00000	99.75
35.5	12,524,292	0	0.00000	1.00000	99.75
36.5	10,819,306	0	0.00000	1.00000	99.75
37.5	9,746,101	35,488	0.00364	0.99636	99.75
38.5	8,331,107	0	0.00000	1.00000	99.39
39.5	6,855,944	0	0.00000	1.00000	99.39
40.5	6,115,090	51,137	0.00836	0.99164	99.39
41.5	5,464,954	0	0.00000	1.00000	98.56
42.5	5,044,338	0	0.00000	1.00000	98.56
43.5	3,836,370	0	0.00000	1.00000	98.56
44.5	3,574,225	3,030	0.00085	0.99915	98.56
45.5	3,472,721	69,086	0.01989	0.98011	98.48
46.5	3,236,885	320,551	0.09903	0.90097	96.52
47.5	2,649,239	458,238	0.17297	0.82703	86.96
48.5	2,073,180	228,665	0.11030	0.88970	71.92
	Totals:	1,475,173			

BC Hydro Power Authority

Account 25102 - Structure, Support, Wood

Placement Band - 1982 - 2019   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 25102 - Structure, Support, Wood

Placement Band - 1982 - 2019   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

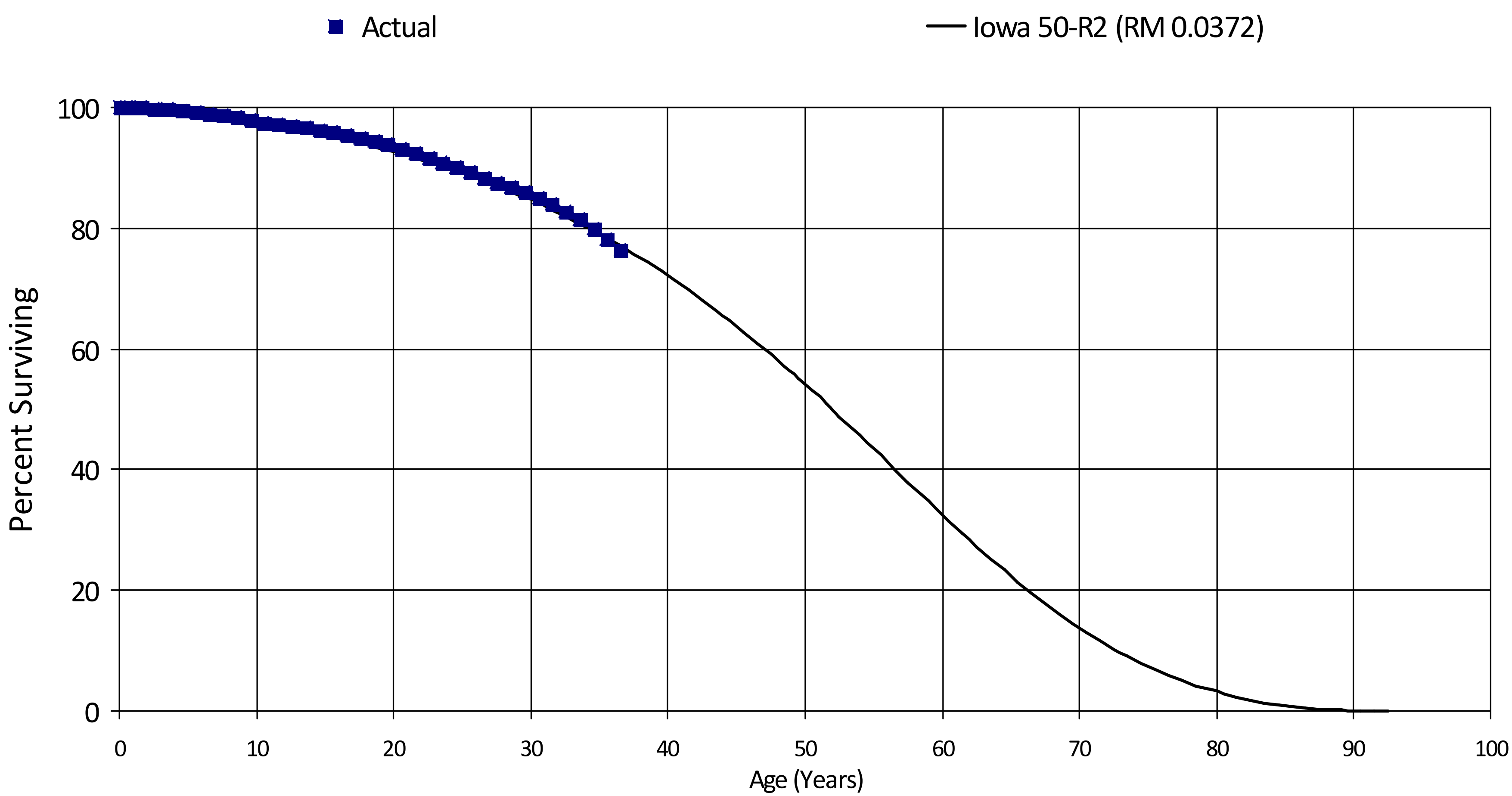
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	8,744,723	0	0.00000	1.00000	100.00
0.5	8,744,723	0	0.00000	1.00000	100.00
1.5	8,597,021	0	0.00000	1.00000	100.00
2.5	8,360,031	0	0.00000	1.00000	100.00
3.5	7,820,289	0	0.00000	1.00000	100.00
4.5	7,161,687	0	0.00000	1.00000	100.00
5.5	7,161,687	0	0.00000	1.00000	100.00
6.5	4,961,387	0	0.00000	1.00000	100.00
7.5	4,793,333	0	0.00000	1.00000	100.00
8.5	3,999,424	0	0.00000	1.00000	100.00
9.5	3,802,145	0	0.00000	1.00000	100.00
10.5	3,359,058	0	0.00000	1.00000	100.00
11.5	2,416,296	0	0.00000	1.00000	100.00
12.5	1,637,474	0	0.00000	1.00000	100.00
13.5	1,181,079	0	0.00000	1.00000	100.00
14.5	883,820	0	0.00000	1.00000	100.00
15.5	818,171	0	0.00000	1.00000	100.00
16.5	747,067	0	0.00000	1.00000	100.00
17.5	483,262	0	0.00000	1.00000	100.00
18.5	357,792	0	0.00000	1.00000	100.00
19.5	216,108	0	0.00000	1.00000	100.00
20.5	169,372	0	0.00000	1.00000	100.00
21.5	123,403	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 25201 - Pole Structures < 60Kv

Placement Band - 1970 - 2020   Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 25201 - Pole Structures < 60Kv

Placement Band - 1970 - 2020 Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,504,712,096	0	0.00000	1.00000	100.00
0.5	1,486,679,383	-62	0.00000	1.00000	100.00
1.5	1,385,153,177	2,716,425	0.00196	0.99804	100.00
2.5	1,275,118,959	2,073,153	0.00163	0.99837	99.80
3.5	1,133,599,527	2,708,322	0.00239	0.99761	99.64
4.5	1,024,682,858	2,632,954	0.00257	0.99743	99.40
5.5	951,815,333	2,359,386	0.00248	0.99752	99.14
6.5	864,959,182	2,298,788	0.00266	0.99734	98.89
7.5	814,804,822	2,115,344	0.00260	0.99740	98.63
8.5	691,665,680	2,566,894	0.00371	0.99629	98.37
9.5	609,843,702	2,675,569	0.00439	0.99561	98.01
10.5	554,417,686	1,939,459	0.00350	0.99650	97.58
11.5	497,677,711	1,774,966	0.00357	0.99643	97.24
12.5	422,909,941	1,322,410	0.00313	0.99687	96.89
13.5	380,217,111	1,474,126	0.00388	0.99612	96.59
14.5	349,938,075	1,465,654	0.00419	0.99581	96.22
15.5	319,678,972	1,716,933	0.00537	0.99463	95.82
16.5	291,296,387	1,524,682	0.00523	0.99477	95.31
17.5	247,533,317	1,208,705	0.00488	0.99512	94.81
18.5	229,417,942	1,336,600	0.00583	0.99417	94.35
19.5	208,547,715	1,424,857	0.00683	0.99317	93.80
20.5	193,272,735	1,436,918	0.00743	0.99257	93.16
21.5	175,730,790	1,468,755	0.00836	0.99164	92.47
22.5	157,628,917	1,387,317	0.00880	0.99120	91.70
23.5	137,126,224	1,211,985	0.00884	0.99116	90.89
24.5	118,909,996	1,059,947	0.00891	0.99109	90.09
25.5	99,812,469	958,558	0.00960	0.99040	89.29
26.5	78,606,653	768,569	0.00978	0.99022	88.43

BC Hydro Power Authority

Account 25201 - Pole Structures < 60Kv

Placement Band - 1970 - 2020 Experience Band - 2011 - 2020

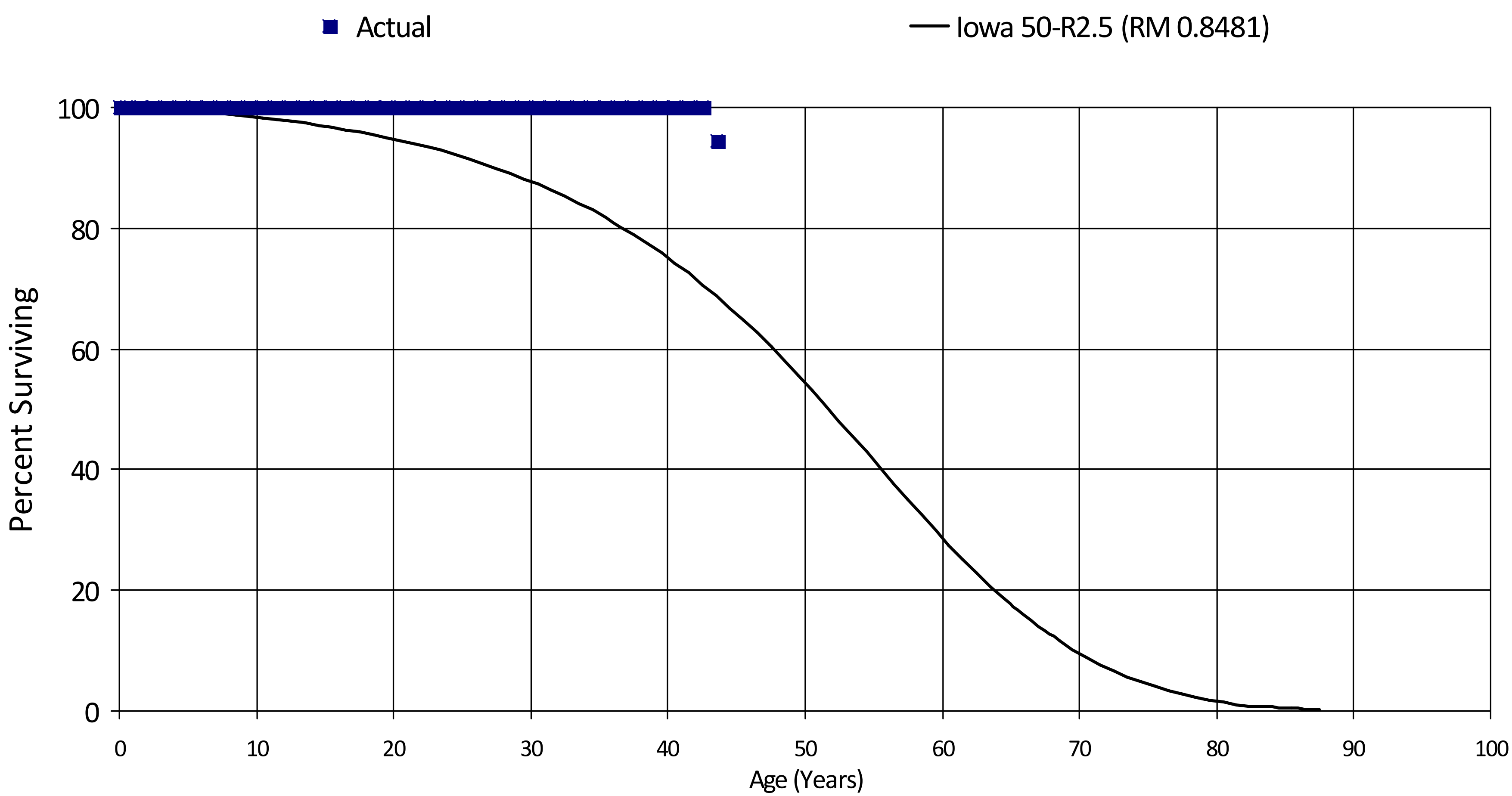
27.5	66,217,990	598,263	0.00903	0.99097	87.57
28.5	52,629,362	493,470	0.00938	0.99062	86.78
29.5	45,173,811	445,463	0.00986	0.99014	85.97
30.5	39,995,730	505,378	0.01264	0.98736	85.12
31.5	37,680,766	550,860	0.01462	0.98538	84.04
32.5	32,206,817	553,551	0.01719	0.98281	82.81
33.5	27,605,523	510,747	0.01850	0.98150	81.39
34.5	24,074,888	486,448	0.02021	0.97979	79.88
35.5	20,257,441	498,400	0.02460	0.97540	78.27
36.5	17,461,101	449,566	0.02575	0.97425	76.34
	Totals:	50,719,360			

BC Hydro Power Authority

Account 25202 - Pole Structures > 60Kv

Placement Band - 1954 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 25202 - Pole Structures > 60Kv

Placement Band - 1954 - 2020 Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	605,135,521	0	0.00000	1.00000	100.00
0.5	579,449,139	0	0.00000	1.00000	100.00
1.5	555,132,019	0	0.00000	1.00000	100.00
2.5	507,235,131	0	0.00000	1.00000	100.00
3.5	496,630,381	0	0.00000	1.00000	100.00
4.5	346,420,629	0	0.00000	1.00000	100.00
5.5	321,493,600	2	0.00000	1.00000	100.00
6.5	277,896,517	0	0.00000	1.00000	100.00
7.5	210,719,153	0	0.00000	1.00000	100.00
8.5	190,657,714	0	0.00000	1.00000	100.00
9.5	163,265,258	0	0.00000	1.00000	100.00
10.5	136,917,503	0	0.00000	1.00000	100.00
11.5	126,003,754	0	0.00000	1.00000	100.00
12.5	109,927,105	0	0.00000	1.00000	100.00
13.5	99,971,579	0	0.00000	1.00000	100.00
14.5	85,478,268	0	0.00000	1.00000	100.00
15.5	81,341,857	0	0.00000	1.00000	100.00
16.5	76,862,568	0	0.00000	1.00000	100.00
17.5	66,439,357	0	0.00000	1.00000	100.00
18.5	62,946,623	0	0.00000	1.00000	100.00
19.5	59,846,648	0	0.00000	1.00000	100.00
20.5	58,183,604	0	0.00000	1.00000	100.00
21.5	54,855,821	0	0.00000	1.00000	100.00
22.5	53,279,137	0	0.00000	1.00000	100.00
23.5	49,713,803	0	0.00000	1.00000	100.00
24.5	46,468,058	0	0.00000	1.00000	100.00
25.5	45,543,914	0	0.00000	1.00000	100.00
26.5	43,094,728	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 25202 - Pole Structures > 60Kv

Placement Band - 1954 - 2020   Experience Band - 2013 - 2020

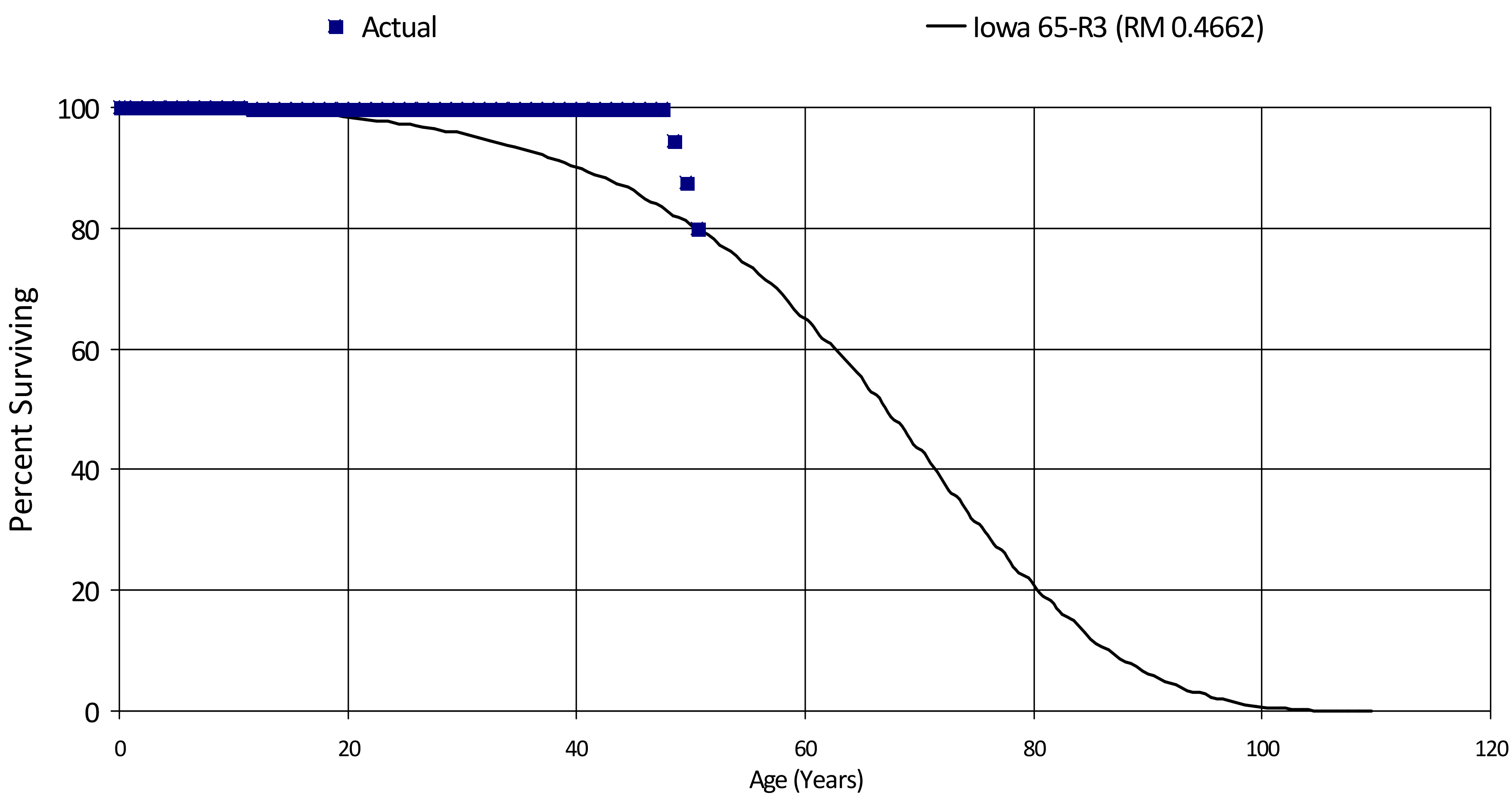
27.5	42,207,376	0	0.00000	1.00000	100.00
28.5	35,560,743	0	0.00000	1.00000	100.00
29.5	34,487,090	0	0.00000	1.00000	100.00
30.5	25,744,579	0	0.00000	1.00000	100.00
31.5	24,992,825	0	0.00000	1.00000	100.00
32.5	24,654,978	0	0.00000	1.00000	100.00
33.5	24,372,073	0	0.00000	1.00000	100.00
34.5	24,068,103	0	0.00000	1.00000	100.00
35.5	23,660,958	0	0.00000	1.00000	100.00
36.5	22,836,961	0	0.00000	1.00000	100.00
37.5	19,778,166	0	0.00000	1.00000	100.00
38.5	18,376,677	0	0.00000	1.00000	100.00
39.5	16,707,500	0	0.00000	1.00000	100.00
40.5	14,150,078	0	0.00000	1.00000	100.00
41.5	10,208,408	0	0.00000	1.00000	100.00
42.5	9,770,749	539,739	0.05524	0.94476	100.00
43.5	7,324,012	2,655,331	0.36255	0.63745	94.48
	Totals:	3,195,072			

BC Hydro Power Authority

Account 25203 - Tower, Lattice / Asthetic

Placement Band - 1957 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 25203 - Tower, Lattice / Asthetic

Placement Band - 1957 - 2020 Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,409,302,030	0	0.00000	1.00000	100.00
0.5	1,408,661,160	0	0.00000	1.00000	100.00
1.5	1,408,462,044	0	0.00000	1.00000	100.00
2.5	1,401,551,180	0	0.00000	1.00000	100.00
3.5	1,399,765,469	0	0.00000	1.00000	100.00
4.5	813,255,206	0	0.00000	1.00000	100.00
5.5	733,310,673	0	0.00000	1.00000	100.00
6.5	434,629,162	0	0.00000	1.00000	100.00
7.5	415,253,975	0	0.00000	1.00000	100.00
8.5	410,780,825	0	0.00000	1.00000	100.00
9.5	399,042,361	0	0.00000	1.00000	100.00
10.5	397,166,732	527,770	0.00133	0.99867	100.00
11.5	387,981,911	0	0.00000	1.00000	99.87
12.5	339,120,421	0	0.00000	1.00000	99.87
13.5	334,271,635	0	0.00000	1.00000	99.87
14.5	326,142,243	0	0.00000	1.00000	99.87
15.5	324,643,071	0	0.00000	1.00000	99.87
16.5	322,015,277	0	0.00000	1.00000	99.87
17.5	320,140,244	0	0.00000	1.00000	99.87
18.5	319,728,922	0	0.00000	1.00000	99.87
19.5	314,516,368	0	0.00000	1.00000	99.87
20.5	298,419,115	0	0.00000	1.00000	99.87
21.5	298,255,247	0	0.00000	1.00000	99.87
22.5	297,986,004	0	0.00000	1.00000	99.87
23.5	297,237,447	0	0.00000	1.00000	99.87
24.5	293,859,069	0	0.00000	1.00000	99.87
25.5	267,492,439	0	0.00000	1.00000	99.87
26.5	266,185,248	0	0.00000	1.00000	99.87

BC Hydro Power Authority

Account 25203 - Tower, Lattice / Asthetic

Placement Band - 1957 - 2020 Experience Band - 2013 - 2020

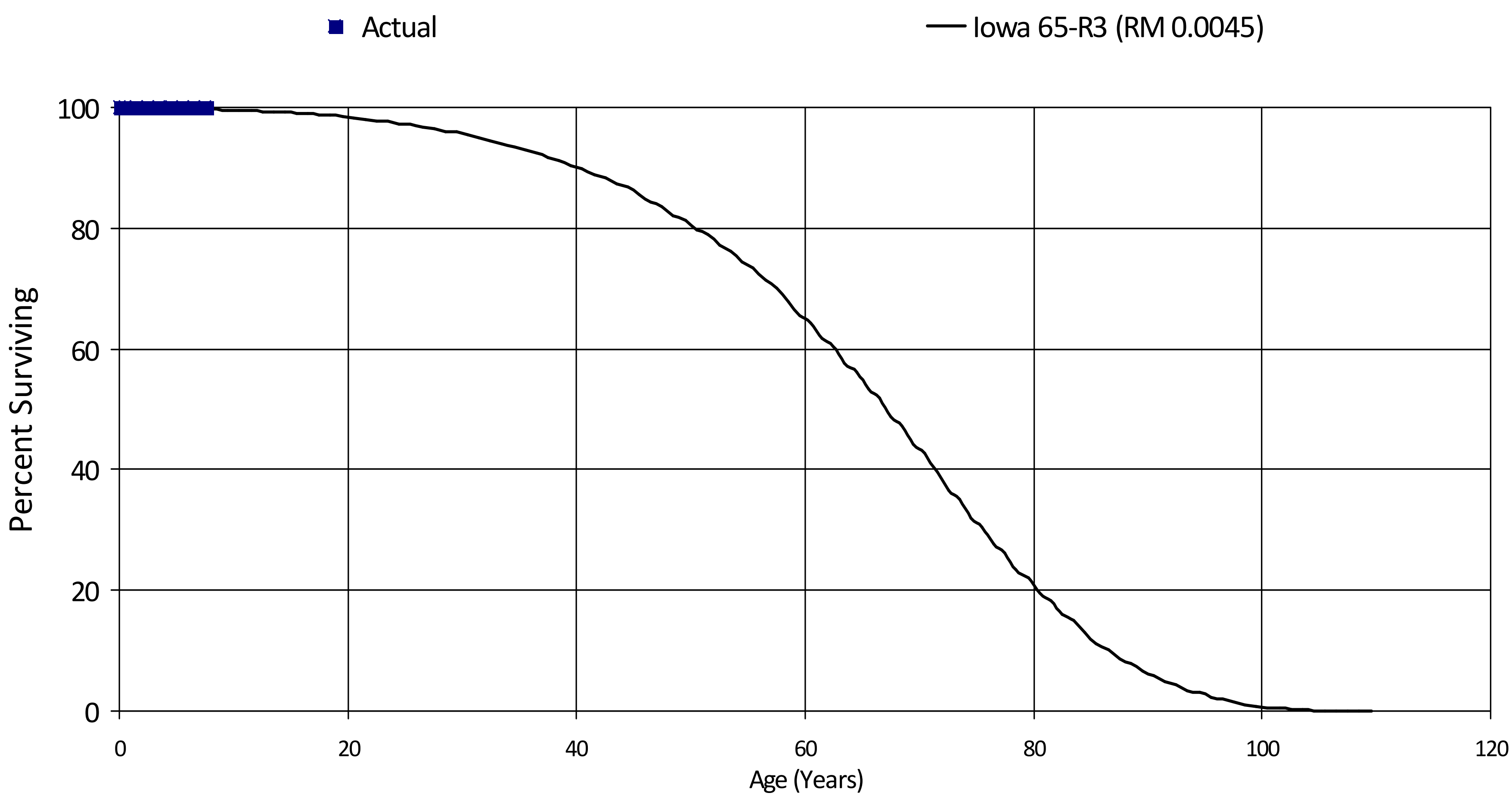
27.5	265,253,410	0	0.00000	1.00000	99.87
28.5	263,448,145	0	0.00000	1.00000	99.87
29.5	255,707,493	0	0.00000	1.00000	99.87
30.5	255,639,896	0	0.00000	1.00000	99.87
31.5	255,533,774	0	0.00000	1.00000	99.87
32.5	255,037,305	0	0.00000	1.00000	99.87
33.5	252,354,987	0	0.00000	1.00000	99.87
34.5	216,570,462	0	0.00000	1.00000	99.87
35.5	190,094,796	0	0.00000	1.00000	99.87
36.5	166,003,068	0	0.00000	1.00000	99.87
37.5	156,485,841	0	0.00000	1.00000	99.87
38.5	126,346,282	0	0.00000	1.00000	99.87
39.5	122,577,321	0	0.00000	1.00000	99.87
40.5	92,065,269	0	0.00000	1.00000	99.87
41.5	80,078,138	0	0.00000	1.00000	99.87
42.5	79,176,054	0	0.00000	1.00000	99.87
43.5	40,963,714	0	0.00000	1.00000	99.87
44.5	39,744,721	0	0.00000	1.00000	99.87
45.5	34,457,963	0	0.00000	1.00000	99.87
46.5	33,936,901	0	0.00000	1.00000	99.87
47.5	32,738,656	1,807,458	0.05521	0.94479	99.87
48.5	29,392,657	2,127,217	0.07237	0.92763	94.36
49.5	20,740,857	1,787,083	0.08616	0.91384	87.53
50.5	16,600,906	1,645,163	0.09910	0.90090	79.99
	Totals:	7,894,691			

BC Hydro Power Authority

Account 25204 - Pole structure, Composite >=60kV

Placement Band - 2012 - 2020   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 25204 - Pole structure, Composite >=60kV

Placement Band - 2012 - 2020   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

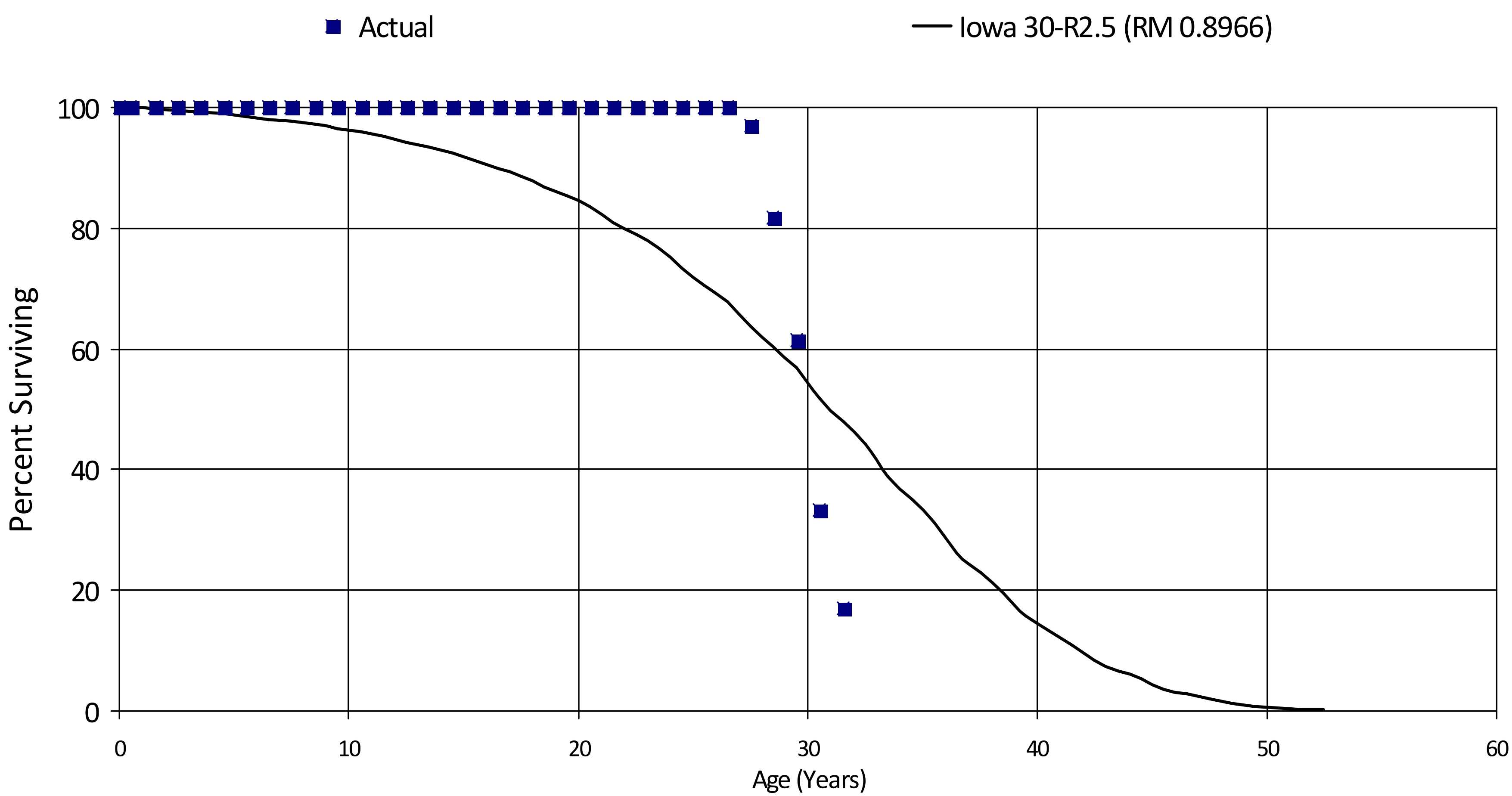
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	7,376,493	0	0.00000	1.00000	100.00
0.5	6,589,610	0	0.00000	1.00000	100.00
1.5	4,252,964	0	0.00000	1.00000	100.00
2.5	2,934,845	0	0.00000	1.00000	100.00
3.5	2,756,356	0	0.00000	1.00000	100.00
4.5	2,052,177	0	0.00000	1.00000	100.00
5.5	2,052,177	0	0.00000	1.00000	100.00
6.5	1,049,896	0	0.00000	1.00000	100.00
7.5	228,531	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 25206 - Pole Structure Cross Arms>60Kv

Placement Band - 1960 - 2020 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 25206 - Pole Structure Cross Arms>60Kv

Placement Band - 1960 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	82,254,262	0	0.00000	1.00000	100.00
0.5	77,180,791	0	0.00000	1.00000	100.00
1.5	77,019,326	0	0.00000	1.00000	100.00
2.5	74,142,644	0	0.00000	1.00000	100.00
3.5	73,786,345	0	0.00000	1.00000	100.00
4.5	66,453,086	0	0.00000	1.00000	100.00
5.5	62,650,097	0	0.00000	1.00000	100.00
6.5	56,862,522	0	0.00000	1.00000	100.00
7.5	48,683,848	0	0.00000	1.00000	100.00
8.5	48,234,008	0	0.00000	1.00000	100.00
9.5	46,350,253	0	0.00000	1.00000	100.00
10.5	42,983,486	0	0.00000	1.00000	100.00
11.5	39,325,199	0	0.00000	1.00000	100.00
12.5	33,187,632	0	0.00000	1.00000	100.00
13.5	29,412,972	0	0.00000	1.00000	100.00
14.5	23,965,802	0	0.00000	1.00000	100.00
15.5	22,451,883	0	0.00000	1.00000	100.00
16.5	20,801,715	0	0.00000	1.00000	100.00
17.5	15,679,388	0	0.00000	1.00000	100.00
18.5	15,679,387	0	0.00000	1.00000	100.00
19.5	14,571,002	0	0.00000	1.00000	100.00
20.5	13,984,249	0	0.00000	1.00000	100.00
21.5	12,843,394	0	0.00000	1.00000	100.00
22.5	12,311,733	0	0.00000	1.00000	100.00
23.5	11,022,508	0	0.00000	1.00000	100.00
24.5	9,998,386	0	0.00000	1.00000	100.00
25.5	9,714,611	0	0.00000	1.00000	100.00
26.5	9,016,850	285,619	0.03168	0.96832	100.00

BC Hydro Power Authority

Account 25206 - Pole Structure Cross Arms>60Kv

Placement Band - 1960 - 2020 Experience Band - 2013 - 2020

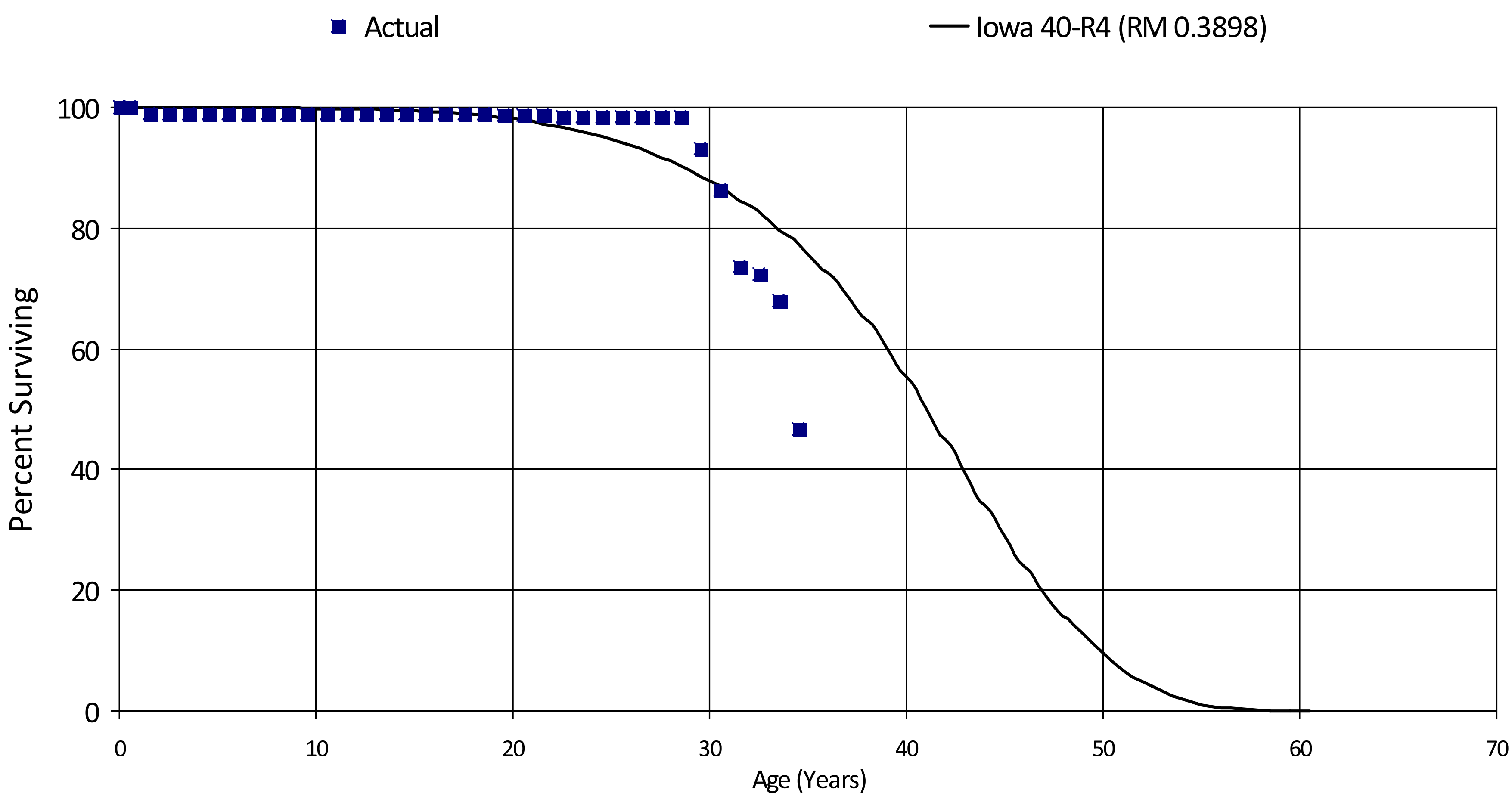
27.5	8,491,563	1,323,827	0.15590	0.84410	96.83
28.5	5,560,210	1,380,342	0.24825	0.75175	81.73
29.5	3,948,748	1,816,692	0.46007	0.53993	61.44
30.5	1,958,948	955,189	0.48760	0.51240	33.17
31.5	1,003,759	1,003,755	1.00000		17.00
	Totals:	6,765,424			

BC Hydro Power Authority

Account 25301 - Foundations

Placement Band - 1971 - 2020 Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 25301 - Foundations

Placement Band - 1971 - 2020   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	300,381,407	0	0.00000	1.00000	100.00
0.5	298,769,002	2,871,944	0.00961	0.99039	100.00
1.5	287,600,479	215,078	0.00075	0.99925	99.04
2.5	266,961,228	0	0.00000	1.00000	98.97
3.5	233,402,231	0	0.00000	1.00000	98.97
4.5	182,349,773	0	0.00000	1.00000	98.97
5.5	161,573,308	0	0.00000	1.00000	98.97
6.5	135,931,927	0	0.00000	1.00000	98.97
7.5	119,958,002	0	0.00000	1.00000	98.97
8.5	108,525,533	0	0.00000	1.00000	98.97
9.5	91,468,101	0	0.00000	1.00000	98.97
10.5	75,147,505	0	0.00000	1.00000	98.97
11.5	63,975,332	0	0.00000	1.00000	98.97
12.5	47,768,285	0	0.00000	1.00000	98.97
13.5	32,027,898	0	0.00000	1.00000	98.97
14.5	28,518,339	0	0.00000	1.00000	98.97
15.5	26,983,231	0	0.00000	1.00000	98.97
16.5	23,101,170	0	0.00000	1.00000	98.97
17.5	19,865,207	0	0.00000	1.00000	98.97
18.5	19,102,496	63,800	0.00334	0.99666	98.97
19.5	18,718,592	0	0.00000	1.00000	98.64
20.5	17,818,507	4,765	0.00027	0.99973	98.64
21.5	16,011,116	6,084	0.00038	0.99962	98.61
22.5	15,126,931	0	0.00000	1.00000	98.57
23.5	14,306,167	0	0.00000	1.00000	98.57
24.5	11,678,623	0	0.00000	1.00000	98.57
25.5	9,602,492	0	0.00000	1.00000	98.57
26.5	8,100,522	0	0.00000	1.00000	98.57

BC Hydro Power Authority

Account 25301 - Foundations

Placement Band - 1971 - 2020   Experience Band - 2012 - 2020

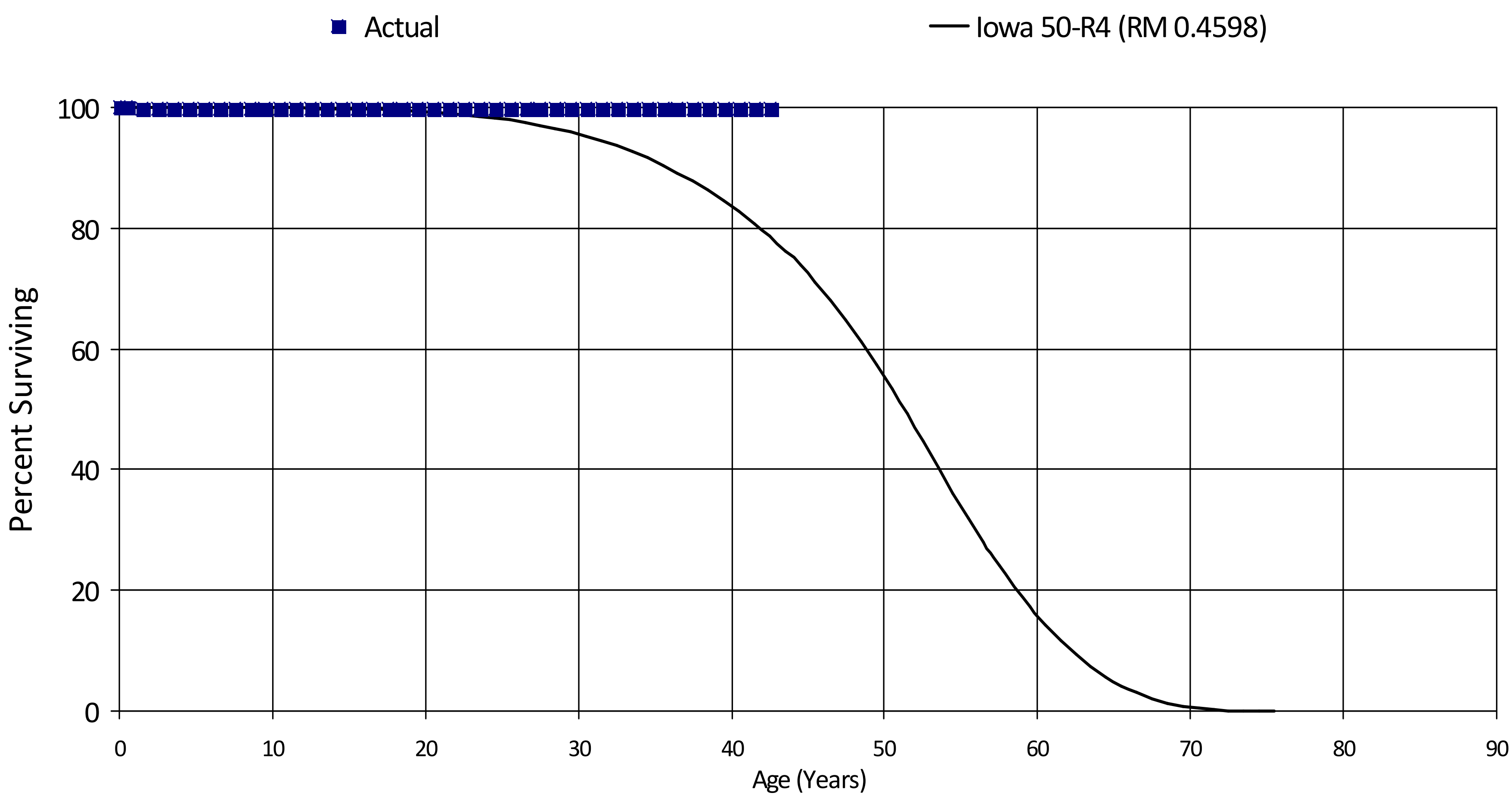
27.5	8,069,751	0	0.00000	1.00000	98.57
28.5	7,689,267	420,902	0.05474	0.94526	98.57
29.5	7,079,882	514,369	0.07265	0.92735	93.17
30.5	6,565,513	971,799	0.14802	0.85198	86.40
31.5	5,593,714	100,314	0.01793	0.98207	73.61
32.5	5,493,400	323,257	0.05884	0.94116	72.29
33.5	5,170,143	1,613,937	0.31216	0.68784	68.04
34.5	3,556,205	1,491,814	0.41950	0.58050	46.80
	Totals:	8,598,063			

BC Hydro Power Authority

Account 25401 - Ducts & Trenches

Placement Band - 1962 - 2019   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 25401 - Ducts & Trenches

Placement Band - 1962 - 2019 Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	71,785,806	0	0.00000	1.00000	100.00
0.5	71,785,806	169,734	0.00236	0.99764	100.00
1.5	60,404,026	0	0.00000	1.00000	99.76
2.5	56,391,340	0	0.00000	1.00000	99.76
3.5	44,165,833	0	0.00000	1.00000	99.76
4.5	32,833,585	0	0.00000	1.00000	99.76
5.5	29,039,342	0	0.00000	1.00000	99.76
6.5	26,539,900	0	0.00000	1.00000	99.76
7.5	23,468,121	0	0.00000	1.00000	99.76
8.5	20,720,173	0	0.00000	1.00000	99.76
9.5	18,289,162	0	0.00000	1.00000	99.76
10.5	17,548,720	0	0.00000	1.00000	99.76
11.5	14,595,013	0	0.00000	1.00000	99.76
12.5	9,738,707	0	0.00000	1.00000	99.76
13.5	7,474,872	0	0.00000	1.00000	99.76
14.5	6,632,673	0	0.00000	1.00000	99.76
15.5	6,607,300	0	0.00000	1.00000	99.76
16.5	6,006,005	0	0.00000	1.00000	99.76
17.5	5,319,320	0	0.00000	1.00000	99.76
18.5	4,817,973	0	0.00000	1.00000	99.76
19.5	4,777,178	0	0.00000	1.00000	99.76
20.5	4,522,028	0	0.00000	1.00000	99.76
21.5	4,443,208	0	0.00000	1.00000	99.76
22.5	4,343,088	0	0.00000	1.00000	99.76
23.5	4,115,925	0	0.00000	1.00000	99.76
24.5	3,663,020	0	0.00000	1.00000	99.76
25.5	3,279,022	0	0.00000	1.00000	99.76
26.5	3,097,424	0	0.00000	1.00000	99.76

BC Hydro Power Authority

Account 25401 - Ducts & Trenches

Placement Band - 1962 - 2019   Experience Band - 2013 - 2020

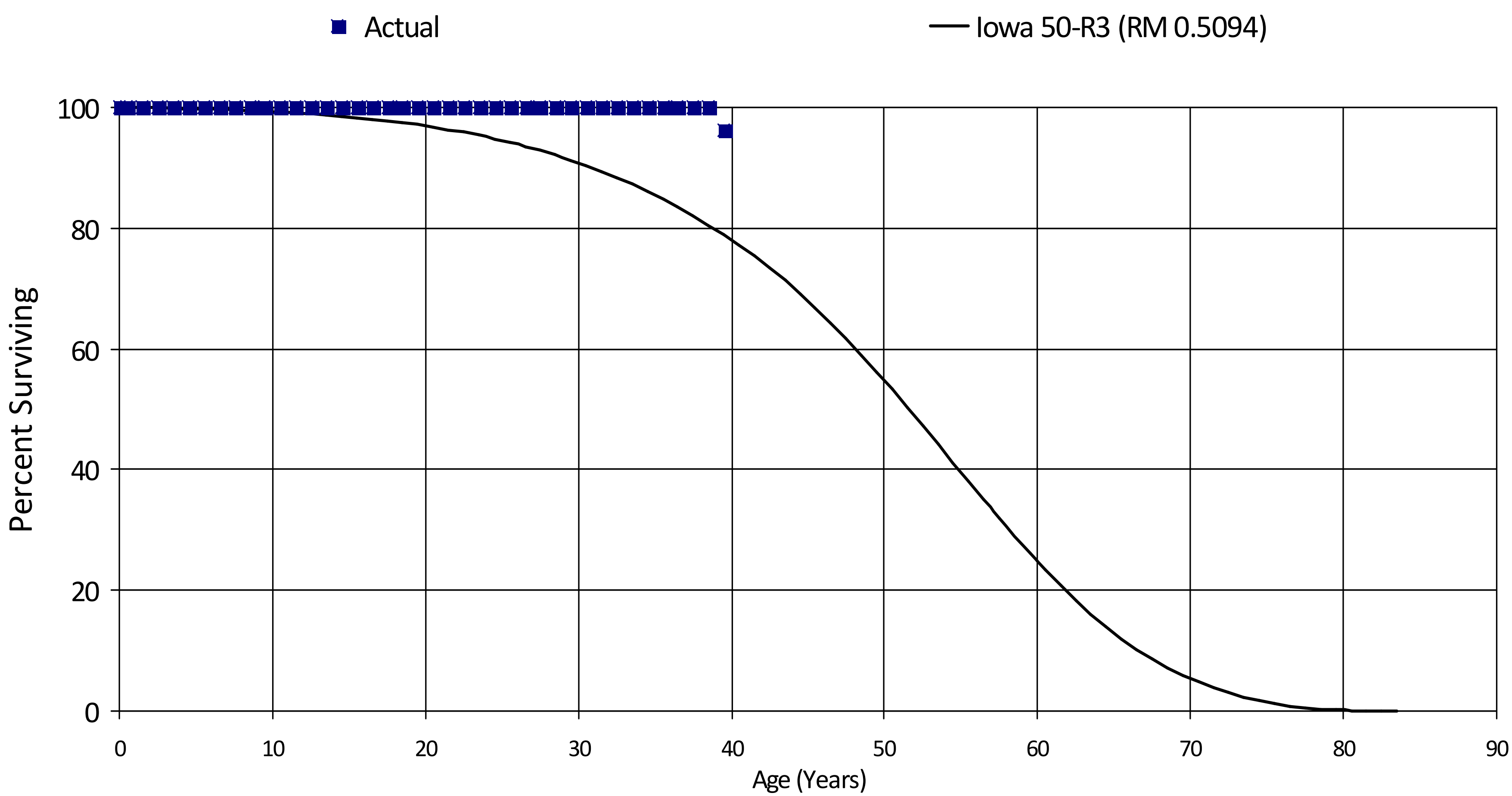
27.5	3,097,071	0	0.00000	1.00000	99.76
28.5	3,028,182	0	0.00000	1.00000	99.76
29.5	2,809,281	0	0.00000	1.00000	99.76
30.5	2,717,059	0	0.00000	1.00000	99.76
31.5	2,696,237	0	0.00000	1.00000	99.76
32.5	2,489,083	0	0.00000	1.00000	99.76
33.5	2,489,083	0	0.00000	1.00000	99.76
34.5	2,419,752	0	0.00000	1.00000	99.76
35.5	2,300,722	0	0.00000	1.00000	99.76
36.5	2,042,028	0	0.00000	1.00000	99.76
37.5	1,967,470	0	0.00000	1.00000	99.76
38.5	1,703,986	0	0.00000	1.00000	99.76
39.5	1,135,071	0	0.00000	1.00000	99.76
40.5	1,083,576	0	0.00000	1.00000	99.76
41.5	1,040,596	0	0.00000	1.00000	99.76
42.5	981,311	75,377	0.07681	0.92319	99.76
	Totals:	245,111			

BC Hydro Power Authority

Account 25501 - Ductbanks < 60Kv

Placement Band - 1962 - 2020 Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 25501 - Ductbanks < 60Kv

Placement Band - 1962 - 2020   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,134,912,712	0	0.00000	1.00000	100.00
0.5	1,104,249,707	0	0.00000	1.00000	100.00
1.5	1,019,226,935	0	0.00000	1.00000	100.00
2.5	950,514,663	0	0.00000	1.00000	100.00
3.5	862,473,516	0	0.00000	1.00000	100.00
4.5	806,310,972	0	0.00000	1.00000	100.00
5.5	743,825,788	0	0.00000	1.00000	100.00
6.5	681,044,105	0	0.00000	1.00000	100.00
7.5	637,192,296	0	0.00000	1.00000	100.00
8.5	552,275,719	0	0.00000	1.00000	100.00
9.5	507,058,077	0	0.00000	1.00000	100.00
10.5	470,244,191	0	0.00000	1.00000	100.00
11.5	407,792,827	0	0.00000	1.00000	100.00
12.5	334,145,200	0	0.00000	1.00000	100.00
13.5	291,485,936	0	0.00000	1.00000	100.00
14.5	261,911,040	0	0.00000	1.00000	100.00
15.5	240,302,236	0	0.00000	1.00000	100.00
16.5	222,084,881	0	0.00000	1.00000	100.00
17.5	196,595,787	0	0.00000	1.00000	100.00
18.5	184,041,124	0	0.00000	1.00000	100.00
19.5	171,432,718	0	0.00000	1.00000	100.00
20.5	162,391,513	0	0.00000	1.00000	100.00
21.5	150,322,417	0	0.00000	1.00000	100.00
22.5	138,483,910	0	0.00000	1.00000	100.00
23.5	127,006,975	0	0.00000	1.00000	100.00
24.5	109,486,491	0	0.00000	1.00000	100.00
25.5	93,194,349	0	0.00000	1.00000	100.00
26.5	79,733,247	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 25501 - Ductbanks < 60Kv

Placement Band - 1962 - 2020 Experience Band - 2012 - 2020

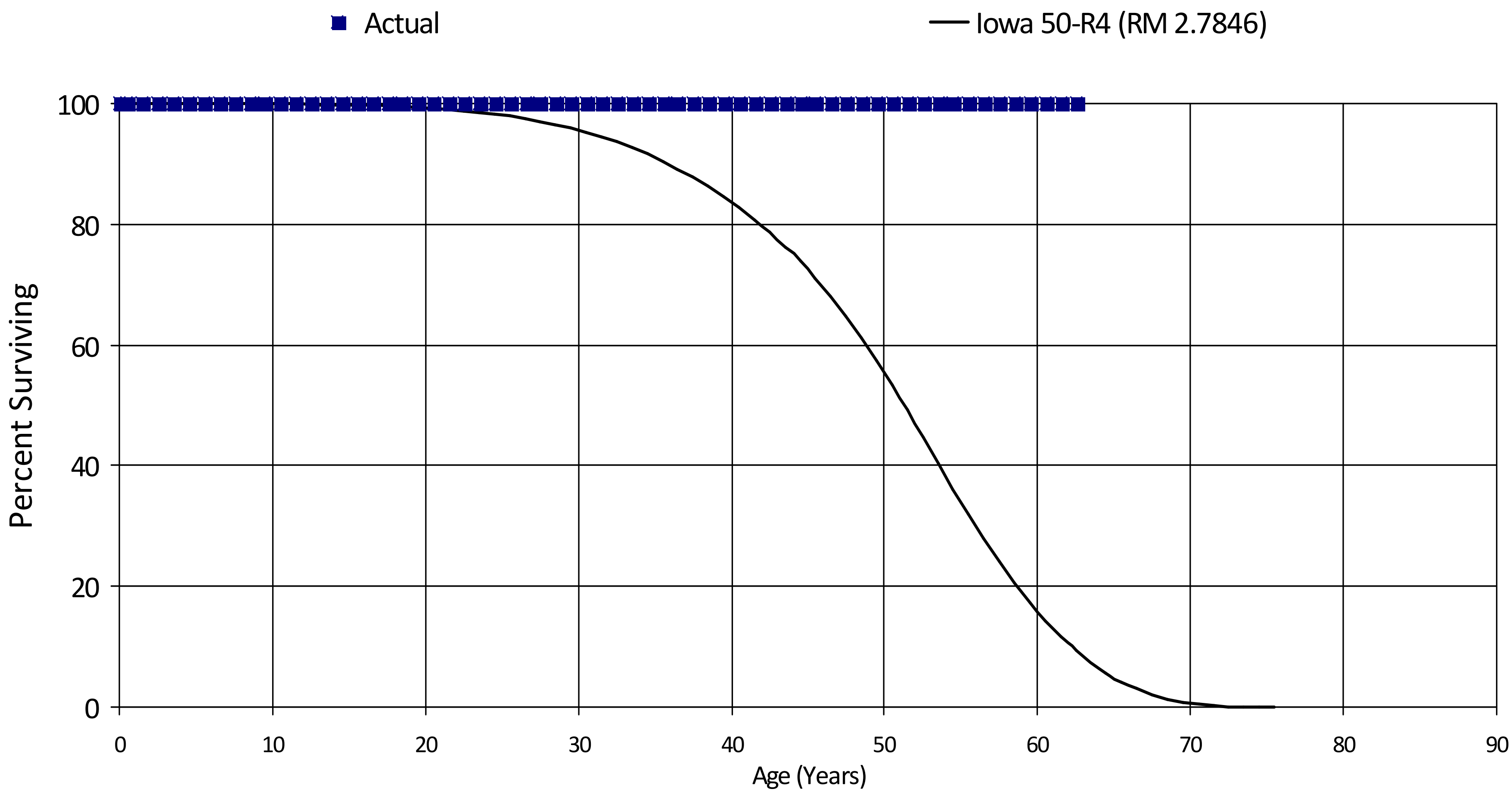
27.5	67,822,220	0	0.00000	1.00000	100.00
28.5	59,275,997	0	0.00000	1.00000	100.00
29.5	51,564,995	0	0.00000	1.00000	100.00
30.5	45,939,411	0	0.00000	1.00000	100.00
31.5	44,219,591	0	0.00000	1.00000	100.00
32.5	42,590,580	0	0.00000	1.00000	100.00
33.5	40,697,974	0	0.00000	1.00000	100.00
34.5	38,135,885	0	0.00000	1.00000	100.00
35.5	34,919,903	0	0.00000	1.00000	100.00
36.5	30,865,454	0	0.00000	1.00000	100.00
37.5	27,044,900	0	0.00000	1.00000	100.00
38.5	21,938,984	810,371	0.03694	0.96306	100.00
39.5	16,439,363	10,857,704	0.66047	0.33953	96.31
	Totals:	11,668,075			

BC Hydro Power Authority

Account 25502 - Ductbanks > 60Kv

Placement Band - 1957 - 2016   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 25502 - Ductbanks > 60Kv

Placement Band - 1957 - 2016   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	68,599,409	0	0.00000	1.00000	100.00
0.5	68,599,409	0	0.00000	1.00000	100.00
1.5	68,599,409	0	0.00000	1.00000	100.00
2.5	68,599,409	0	0.00000	1.00000	100.00
3.5	68,599,409	0	0.00000	1.00000	100.00
4.5	64,717,563	0	0.00000	1.00000	100.00
5.5	64,413,664	0	0.00000	1.00000	100.00
6.5	25,951,417	0	0.00000	1.00000	100.00
7.5	25,618,349	0	0.00000	1.00000	100.00
8.5	25,618,349	0	0.00000	1.00000	100.00
9.5	24,973,137	0	0.00000	1.00000	100.00
10.5	24,754,279	0	0.00000	1.00000	100.00
11.5	24,337,136	0	0.00000	1.00000	100.00
12.5	21,201,663	0	0.00000	1.00000	100.00
13.5	20,963,161	0	0.00000	1.00000	100.00
14.5	20,481,218	0	0.00000	1.00000	100.00
15.5	10,063,931	0	0.00000	1.00000	100.00
16.5	9,976,593	0	0.00000	1.00000	100.00
17.5	5,215,889	0	0.00000	1.00000	100.00
18.5	5,215,889	0	0.00000	1.00000	100.00
19.5	5,193,846	0	0.00000	1.00000	100.00
20.5	5,193,846	0	0.00000	1.00000	100.00
21.5	5,191,134	0	0.00000	1.00000	100.00
22.5	5,191,134	0	0.00000	1.00000	100.00
23.5	5,088,822	0	0.00000	1.00000	100.00
24.5	5,010,808	0	0.00000	1.00000	100.00
25.5	4,972,558	0	0.00000	1.00000	100.00
26.5	4,972,558	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 25502 - Ductbanks > 60Kv

Placement Band - 1957 - 2016   Experience Band - 2020 - 2020

27.5	4,972,558	0	0.00000	1.00000	100.00
28.5	4,972,558	0	0.00000	1.00000	100.00
29.5	4,972,558	0	0.00000	1.00000	100.00
30.5	4,962,777	0	0.00000	1.00000	100.00
31.5	4,962,549	0	0.00000	1.00000	100.00
32.5	4,954,149	0	0.00000	1.00000	100.00
33.5	4,954,149	0	0.00000	1.00000	100.00
34.5	4,954,149	0	0.00000	1.00000	100.00
35.5	4,954,149	0	0.00000	1.00000	100.00
36.5	4,930,616	0	0.00000	1.00000	100.00
37.5	4,930,616	0	0.00000	1.00000	100.00
38.5	4,798,087	0	0.00000	1.00000	100.00
39.5	4,454,863	0	0.00000	1.00000	100.00
40.5	4,454,863	0	0.00000	1.00000	100.00
41.5	4,195,735	0	0.00000	1.00000	100.00
42.5	3,560,707	0	0.00000	1.00000	100.00
43.5	3,560,185	0	0.00000	1.00000	100.00
44.5	3,541,954	0	0.00000	1.00000	100.00
45.5	3,134,955	0	0.00000	1.00000	100.00
46.5	3,134,955	0	0.00000	1.00000	100.00
47.5	3,134,955	0	0.00000	1.00000	100.00
48.5	3,134,955	0	0.00000	1.00000	100.00
49.5	3,129,204	0	0.00000	1.00000	100.00
50.5	3,127,810	0	0.00000	1.00000	100.00
51.5	3,124,812	0	0.00000	1.00000	100.00
52.5	3,124,812	0	0.00000	1.00000	100.00
53.5	3,124,812	0	0.00000	1.00000	100.00
54.5	3,124,812	0	0.00000	1.00000	100.00
55.5	3,124,812	0	0.00000	1.00000	100.00
56.5	3,124,812	0	0.00000	1.00000	100.00
57.5	3,124,812	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 25502 - Ductbanks > 60Kv

Placement Band - 1957 - 2016 Experience Band - 2020 - 2020

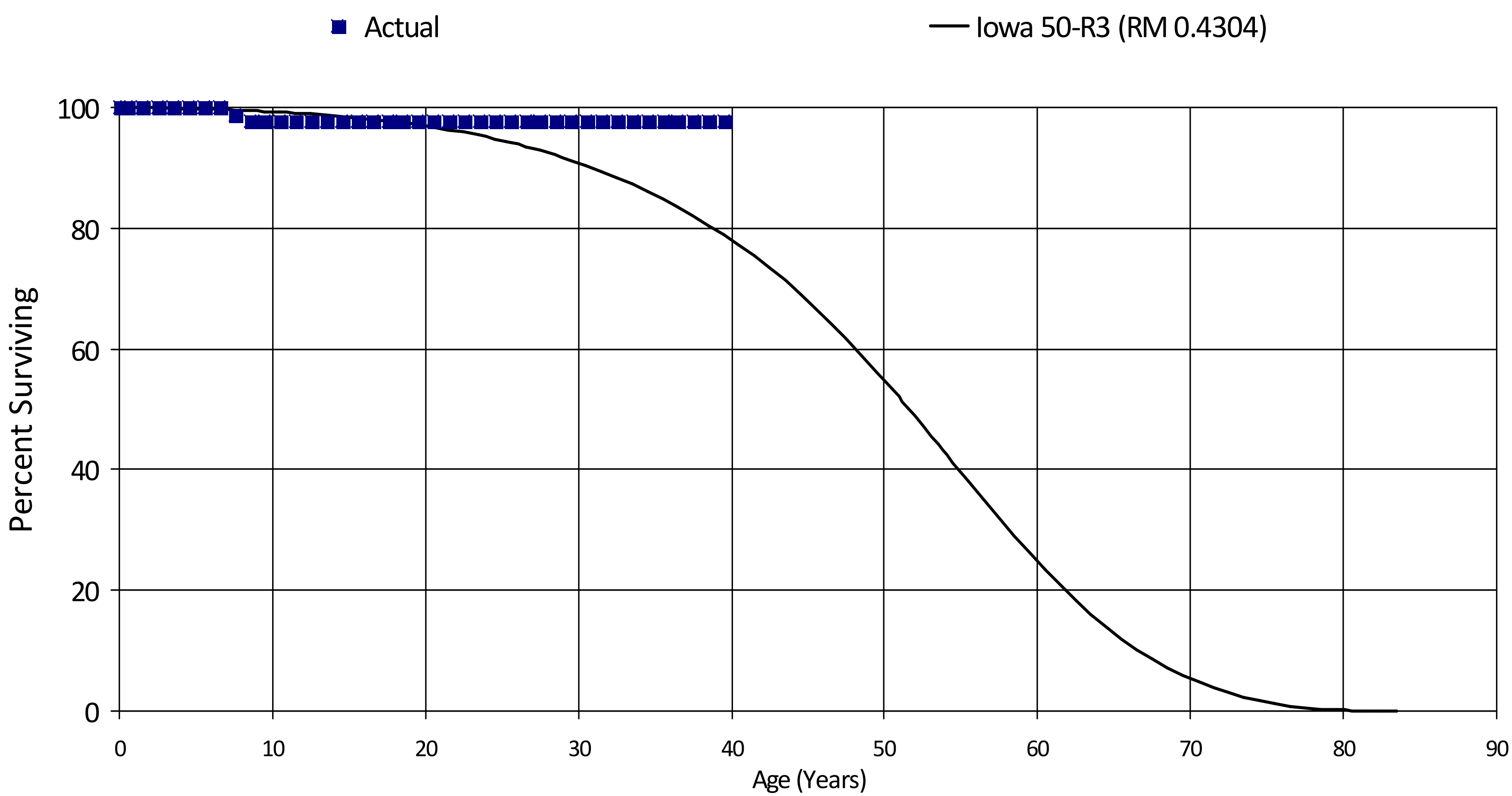
58.5	3,124,812	0	0.00000	1.00000	100.00
59.5	3,124,812	0	0.00000	1.00000	100.00
60.5	3,124,812	0	0.00000	1.00000	100.00
61.5	3,124,812	0	0.00000	1.00000	100.00
62.5	3,124,812	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 25601 - Barriers & Enclosures

Placement Band - 1968 - 2019 Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 25601 - Barriers & Enclosures

Placement Band - 1968 - 2019 Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	15,830,615	0	0.00000	1.00000	100.00
0.5	15,830,615	0	0.00000	1.00000	100.00
1.5	15,590,523	0	0.00000	1.00000	100.00
2.5	14,478,766	0	0.00000	1.00000	100.00
3.5	13,549,590	0	0.00000	1.00000	100.00
4.5	11,237,872	0	0.00000	1.00000	100.00
5.5	11,144,665	0	0.00000	1.00000	100.00
6.5	10,650,313	124,324	0.01167	0.98833	100.00
7.5	10,494,279	128,942	0.01229	0.98771	98.83
8.5	7,821,376	0	0.00000	1.00000	97.62
9.5	7,356,685	0	0.00000	1.00000	97.62
10.5	6,902,403	0	0.00000	1.00000	97.62
11.5	4,149,514	0	0.00000	1.00000	97.62
12.5	3,285,228	0	0.00000	1.00000	97.62
13.5	3,165,250	0	0.00000	1.00000	97.62
14.5	2,259,114	0	0.00000	1.00000	97.62
15.5	1,332,907	0	0.00000	1.00000	97.62
16.5	1,277,356	0	0.00000	1.00000	97.62
17.5	1,150,511	0	0.00000	1.00000	97.62
18.5	905,372	0	0.00000	1.00000	97.62
19.5	865,239	0	0.00000	1.00000	97.62
20.5	776,923	0	0.00000	1.00000	97.62
21.5	617,277	0	0.00000	1.00000	97.62
22.5	585,755	0	0.00000	1.00000	97.62
23.5	569,821	0	0.00000	1.00000	97.62
24.5	550,092	0	0.00000	1.00000	97.62
25.5	548,593	0	0.00000	1.00000	97.62
26.5	506,792	0	0.00000	1.00000	97.62

BC Hydro Power Authority

Account 25601 - Barriers & Enclosures

Placement Band - 1968 - 2019 Experience Band - 2012 - 2020

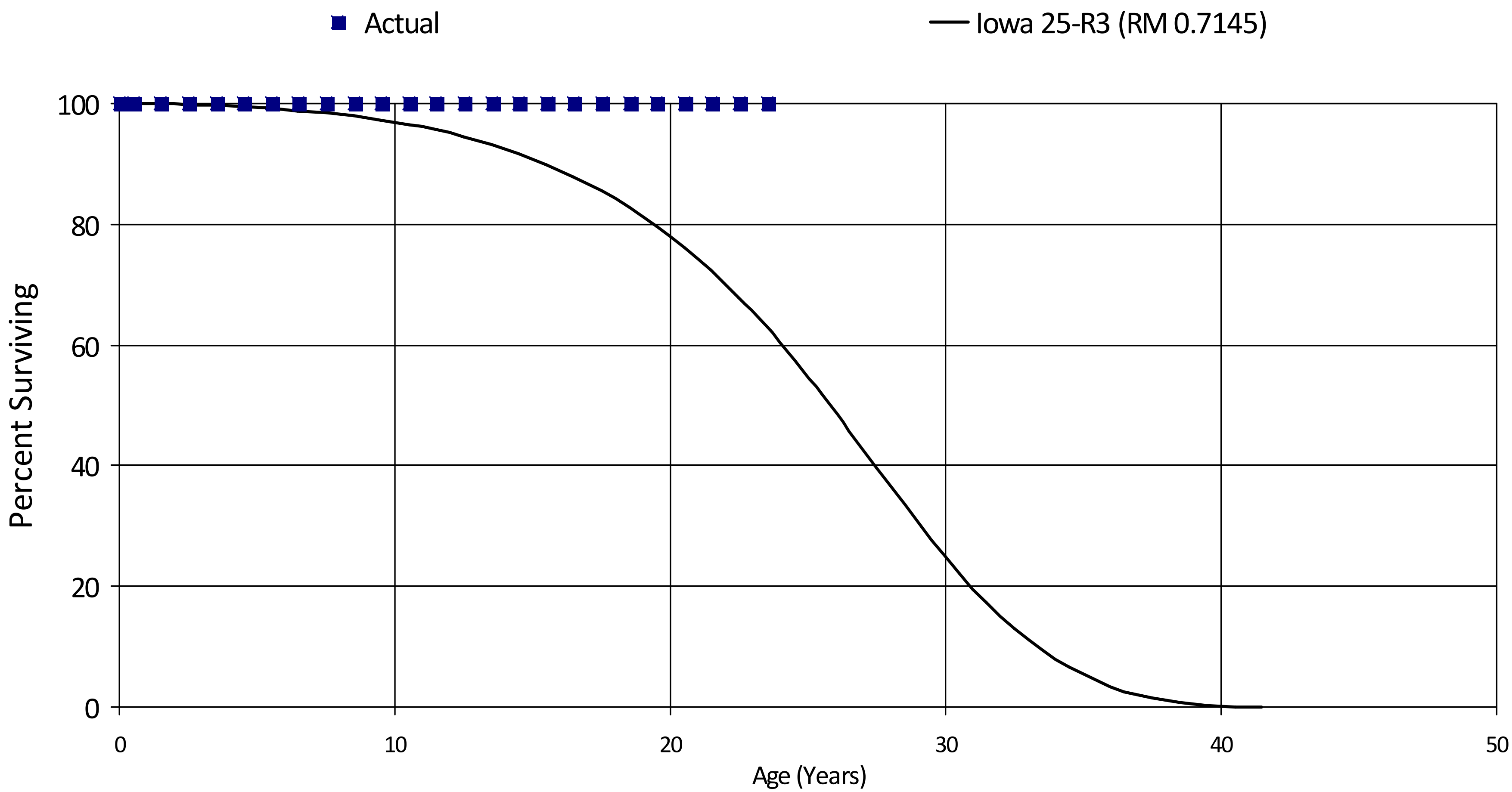
27.5	506,649	0	0.00000	1.00000	97.62
28.5	428,867	0	0.00000	1.00000	97.62
29.5	360,873	0	0.00000	1.00000	97.62
30.5	263,178	0	0.00000	1.00000	97.62
31.5	263,178	0	0.00000	1.00000	97.62
32.5	263,178	0	0.00000	1.00000	97.62
33.5	263,178	0	0.00000	1.00000	97.62
34.5	263,178	0	0.00000	1.00000	97.62
35.5	263,178	0	0.00000	1.00000	97.62
36.5	256,365	0	0.00000	1.00000	97.62
37.5	256,365	0	0.00000	1.00000	97.62
38.5	213,761	0	0.00000	1.00000	97.62
39.5	188,687	0	0.00000	1.00000	97.62
	Totals:	253,266			

BC Hydro Power Authority

Account 25701 - Capacitor, <60 Kv

Placement Band - 1996 - 2020 Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 25701 - Capacitor, <60 Kv

Placement Band - 1996 - 2020   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

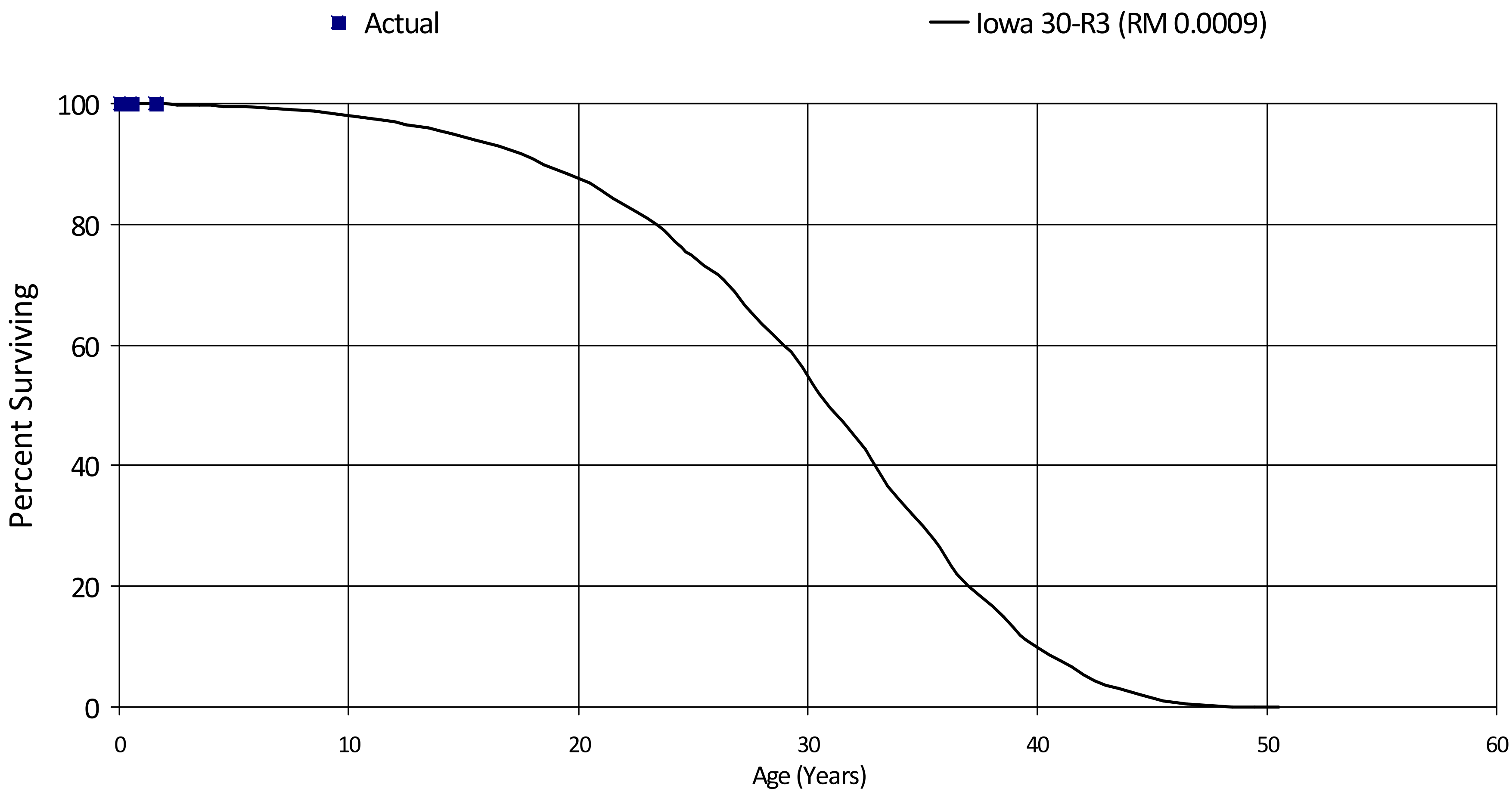
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	3,354,739	0	0.00000	1.00000	100.00
0.5	3,352,680	0	0.00000	1.00000	100.00
1.5	3,120,863	0	0.00000	1.00000	100.00
2.5	2,710,109	0	0.00000	1.00000	100.00
3.5	2,636,511	0	0.00000	1.00000	100.00
4.5	2,501,733	0	0.00000	1.00000	100.00
5.5	2,492,613	0	0.00000	1.00000	100.00
6.5	2,399,740	0	0.00000	1.00000	100.00
7.5	2,242,646	0	0.00000	1.00000	100.00
8.5	2,040,288	0	0.00000	1.00000	100.00
9.5	1,841,920	0	0.00000	1.00000	100.00
10.5	1,653,220	0	0.00000	1.00000	100.00
11.5	1,408,496	0	0.00000	1.00000	100.00
12.5	1,366,697	0	0.00000	1.00000	100.00
13.5	1,260,350	0	0.00000	1.00000	100.00
14.5	1,201,693	0	0.00000	1.00000	100.00
15.5	1,161,118	0	0.00000	1.00000	100.00
16.5	1,142,021	0	0.00000	1.00000	100.00
17.5	1,130,989	0	0.00000	1.00000	100.00
18.5	990,918	0	0.00000	1.00000	100.00
19.5	990,918	0	0.00000	1.00000	100.00
20.5	990,918	0	0.00000	1.00000	100.00
21.5	835,391	0	0.00000	1.00000	100.00
22.5	741,619	0	0.00000	1.00000	100.00
23.5	106,008	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 30204 - Superheater, Low Temp

Placement Band - 1995 - 2018 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 30204 - Superheater, Low Temp

Placement Band - 1995 - 2018   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

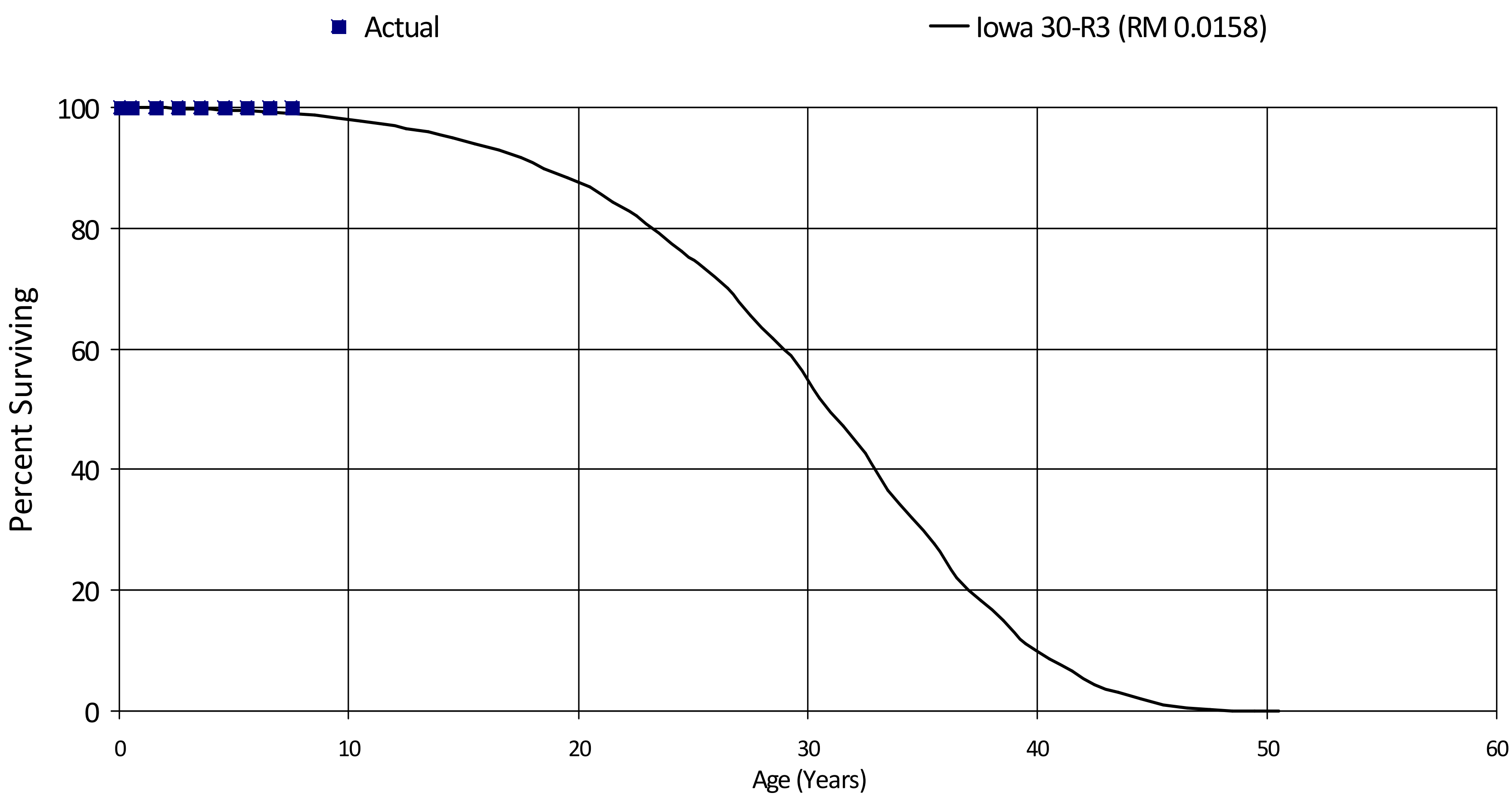
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	141,701	0	0.00000	1.00000	100.00
0.5	141,701	0	0.00000	1.00000	100.00
1.5	141,701	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 30401 - Valves, Safety

Placement Band - 1997 - 2017   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 30401 - Valves, Safety

Placement Band - 1997 - 2017   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

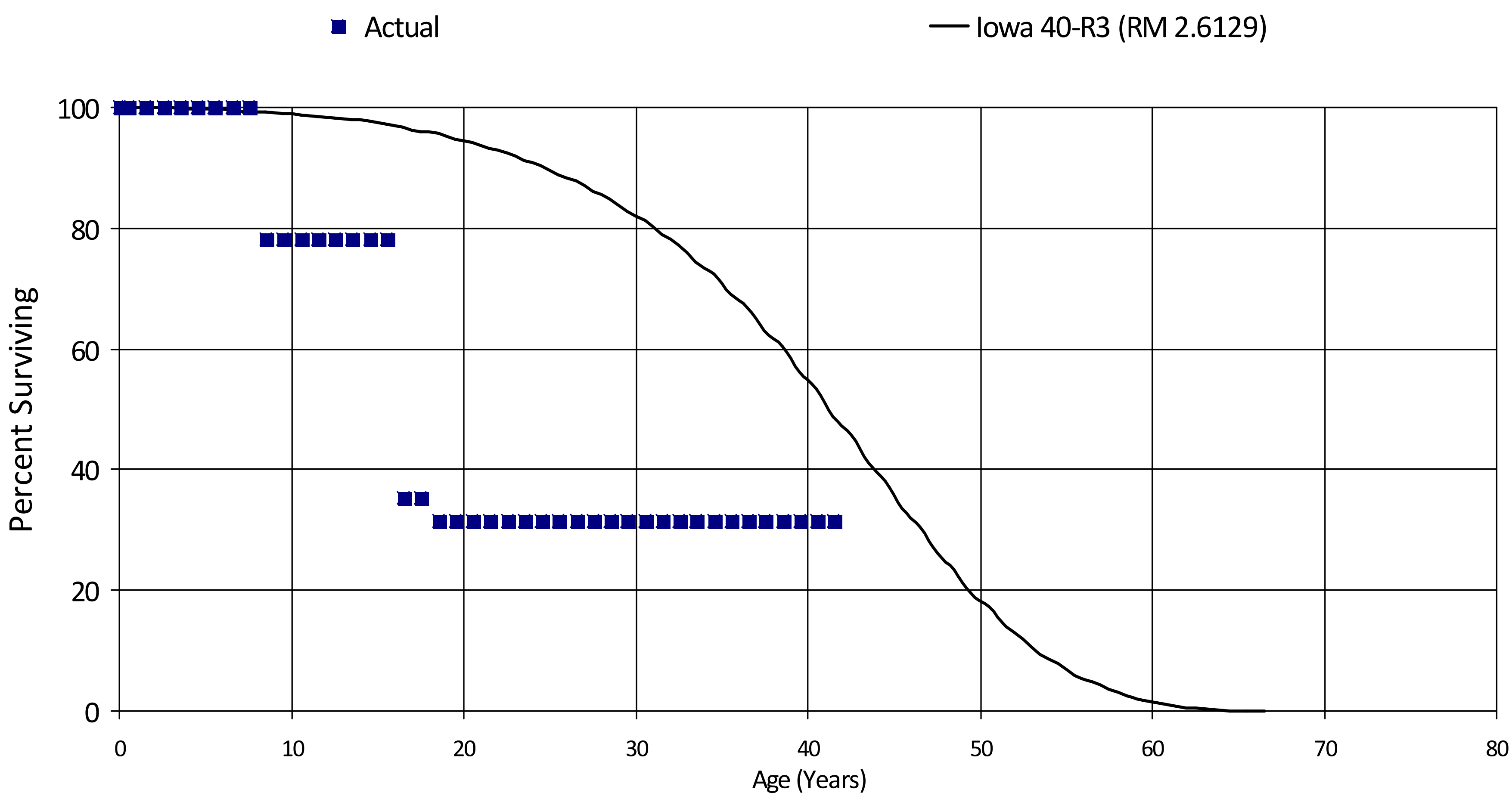
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,381,521	0	0.00000	1.00000	100.00
0.5	2,381,521	0	0.00000	1.00000	100.00
1.5	2,381,521	0	0.00000	1.00000	100.00
2.5	2,381,521	0	0.00000	1.00000	100.00
3.5	2,193,993	0	0.00000	1.00000	100.00
4.5	2,185,826	0	0.00000	1.00000	100.00
5.5	2,185,826	0	0.00000	1.00000	100.00
6.5	2,185,826	0	0.00000	1.00000	100.00
7.5	2,185,826	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 30501 - Piping, High Pressure

Placement Band - 1963 - 2019 Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 30501 - Piping, High Pressure

Placement Band - 1963 - 2019   Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	16,976,469	0	0.00000	1.00000	100.00
0.5	16,976,469	0	0.00000	1.00000	100.00
1.5	3,985,421	0	0.00000	1.00000	100.00
2.5	3,803,237	0	0.00000	1.00000	100.00
3.5	2,903,542	0	0.00000	1.00000	100.00
4.5	2,903,542	0	0.00000	1.00000	100.00
5.5	2,903,542	0	0.00000	1.00000	100.00
6.5	2,903,542	0	0.00000	1.00000	100.00
7.5	646,472	141,193	0.21841	0.78159	100.00
8.5	505,279	0	0.00000	1.00000	78.16
9.5	505,279	0	0.00000	1.00000	78.16
10.5	505,279	0	0.00000	1.00000	78.16
11.5	505,279	0	0.00000	1.00000	78.16
12.5	505,279	0	0.00000	1.00000	78.16
13.5	505,279	0	0.00000	1.00000	78.16
14.5	505,279	0	0.00000	1.00000	78.16
15.5	505,279	276,890	0.54799	0.45201	78.16
16.5	228,389	0	0.00000	1.00000	35.33
17.5	221,966	23,817	0.10730	0.89270	35.33
18.5	198,149	0	0.00000	1.00000	31.54
19.5	198,149	0	0.00000	1.00000	31.54
20.5	198,149	0	0.00000	1.00000	31.54
21.5	198,149	0	0.00000	1.00000	31.54
22.5	198,149	0	0.00000	1.00000	31.54
23.5	198,149	0	0.00000	1.00000	31.54
24.5	198,149	0	0.00000	1.00000	31.54
25.5	198,149	0	0.00000	1.00000	31.54
26.5	198,149	0	0.00000	1.00000	31.54

BC Hydro Power Authority

Account 30501 - Piping, High Pressure

Placement Band - 1963 - 2019 Experience Band - 2014 - 2020

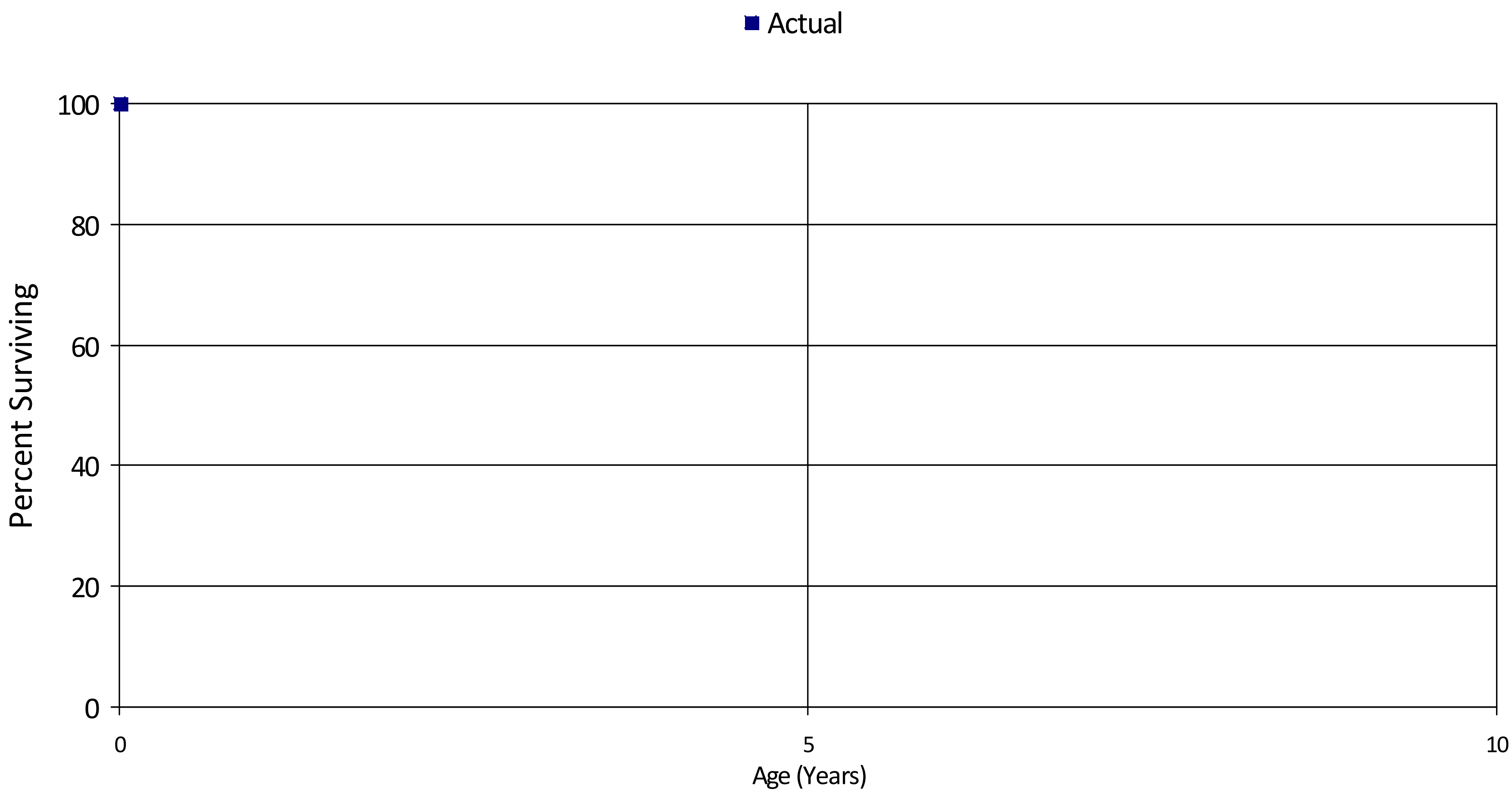
27.5	198,149	0	0.00000	1.00000	31.54
28.5	198,149	0	0.00000	1.00000	31.54
29.5	198,149	0	0.00000	1.00000	31.54
30.5	198,149	0	0.00000	1.00000	31.54
31.5	198,149	0	0.00000	1.00000	31.54
32.5	198,149	0	0.00000	1.00000	31.54
33.5	198,149	0	0.00000	1.00000	31.54
34.5	198,149	0	0.00000	1.00000	31.54
35.5	198,149	0	0.00000	1.00000	31.54
36.5	198,149	0	0.00000	1.00000	31.54
37.5	198,149	0	0.00000	1.00000	31.54
38.5	198,149	0	0.00000	1.00000	31.54
39.5	198,149	0	0.00000	1.00000	31.54
40.5	198,149	0	0.00000	1.00000	31.54
41.5	198,149	144,198	0.72773	0.27227	31.54
	Totals:	586,098			

BC Hydro Power Authority

Account 30604 - Preheater, Air

Placement Band - 2001 - 2001   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 30604 - Preheater, Air

Placement Band - 2001 - 2001   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

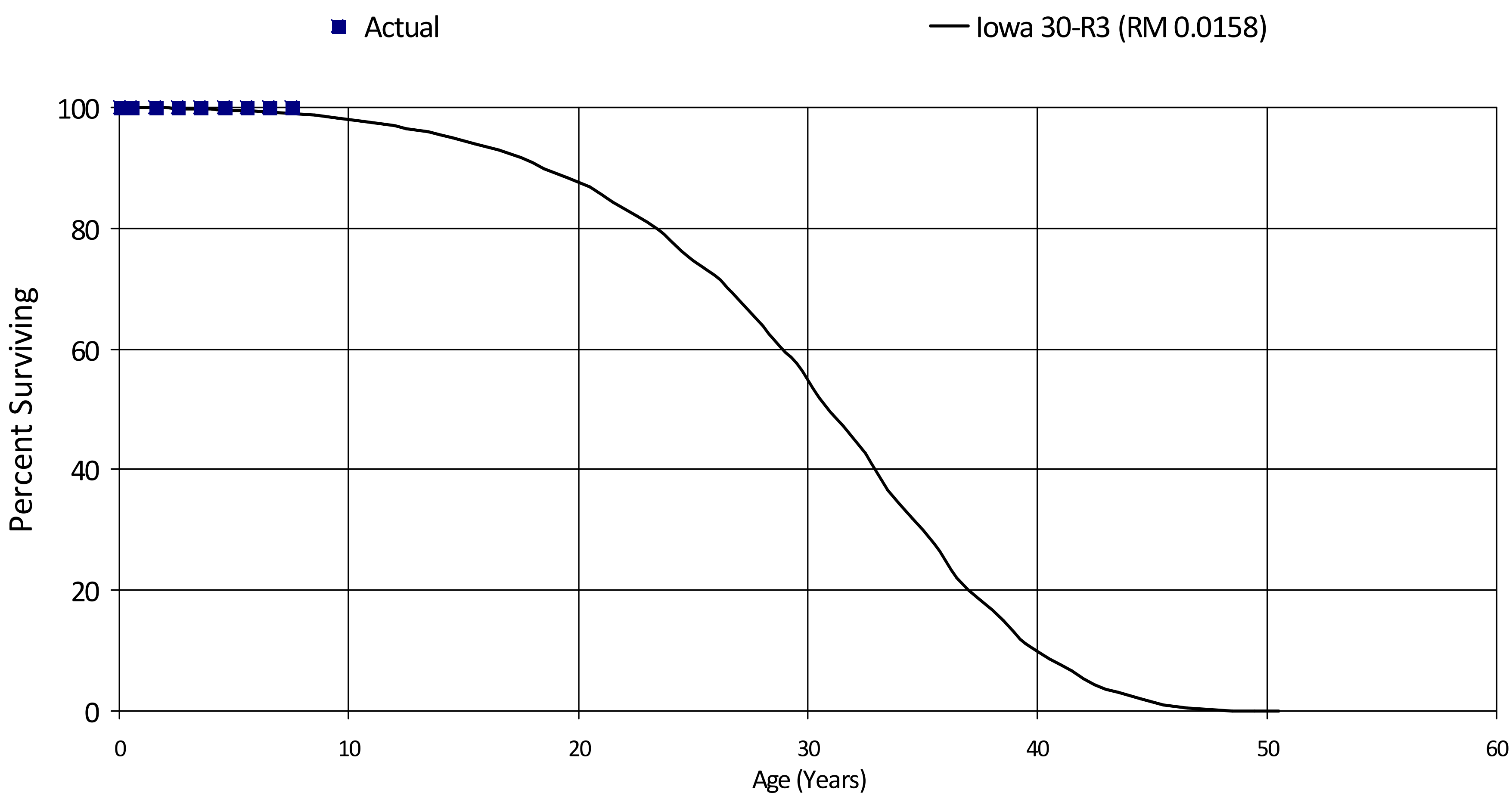
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	0	0	0.00000	0.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 30606 - Instrumentation, Boiler

Placement Band - 1993 - 2017   Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 30606 - Instrumentation, Boiler

Placement Band - 1993 - 2017   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

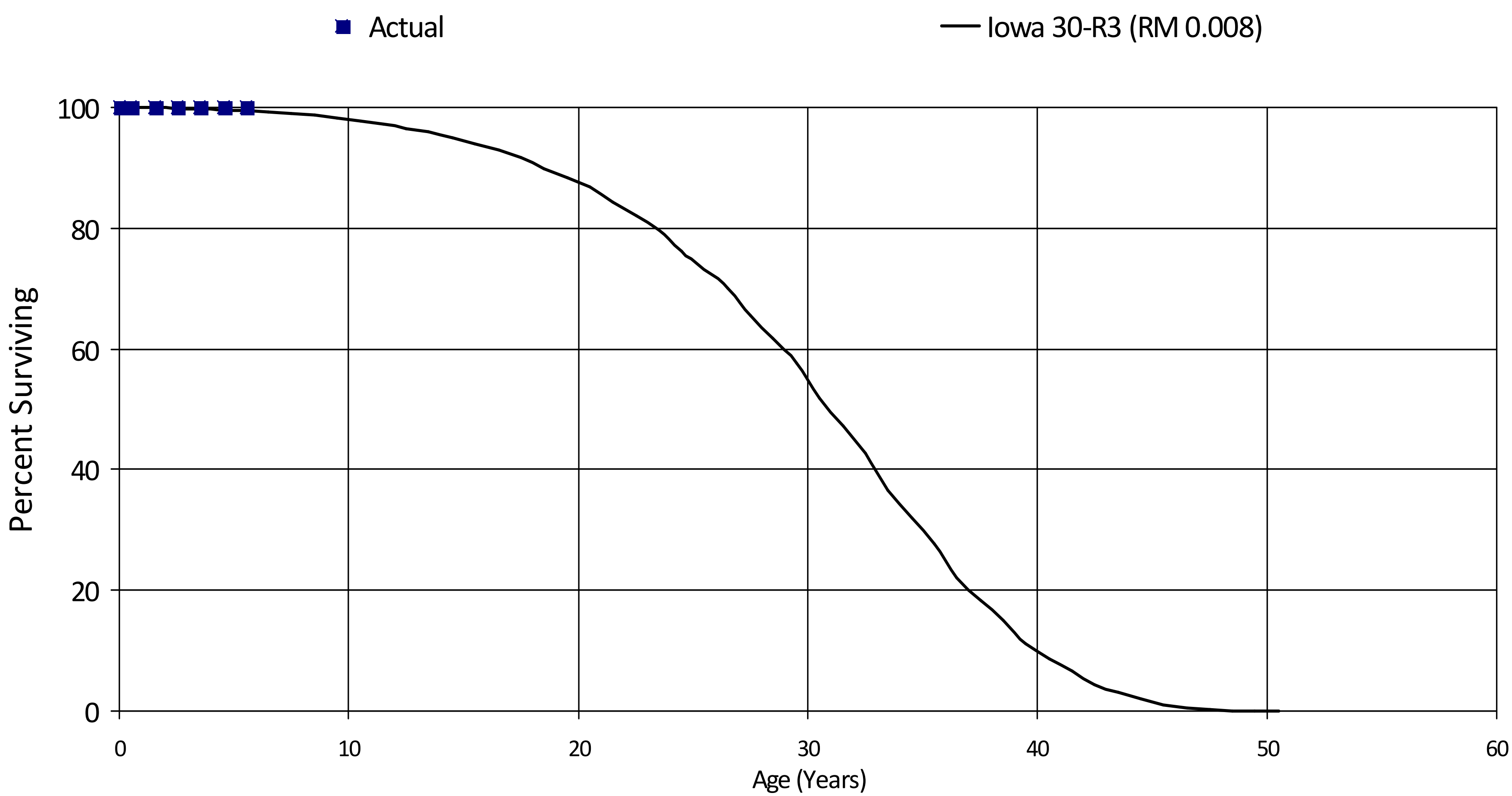
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	117,496	0	0.00000	1.00000	100.00
0.5	117,496	0	0.00000	1.00000	100.00
1.5	117,496	0	0.00000	1.00000	100.00
2.5	117,496	0	0.00000	1.00000	100.00
3.5	16,105	0	0.00000	1.00000	100.00
4.5	16,105	0	0.00000	1.00000	100.00
5.5	16,105	0	0.00000	1.00000	100.00
6.5	16,105	0	0.00000	1.00000	100.00
7.5	16,105	16,105	1.00002	-0.00002	100.00
	Totals:	16,105			

BC Hydro Power Authority

Account 30609 - Seals, Crown

Placement Band - 1995 - 2014 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 30609 - Seals, Crown

Placement Band - 1995 - 2014   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

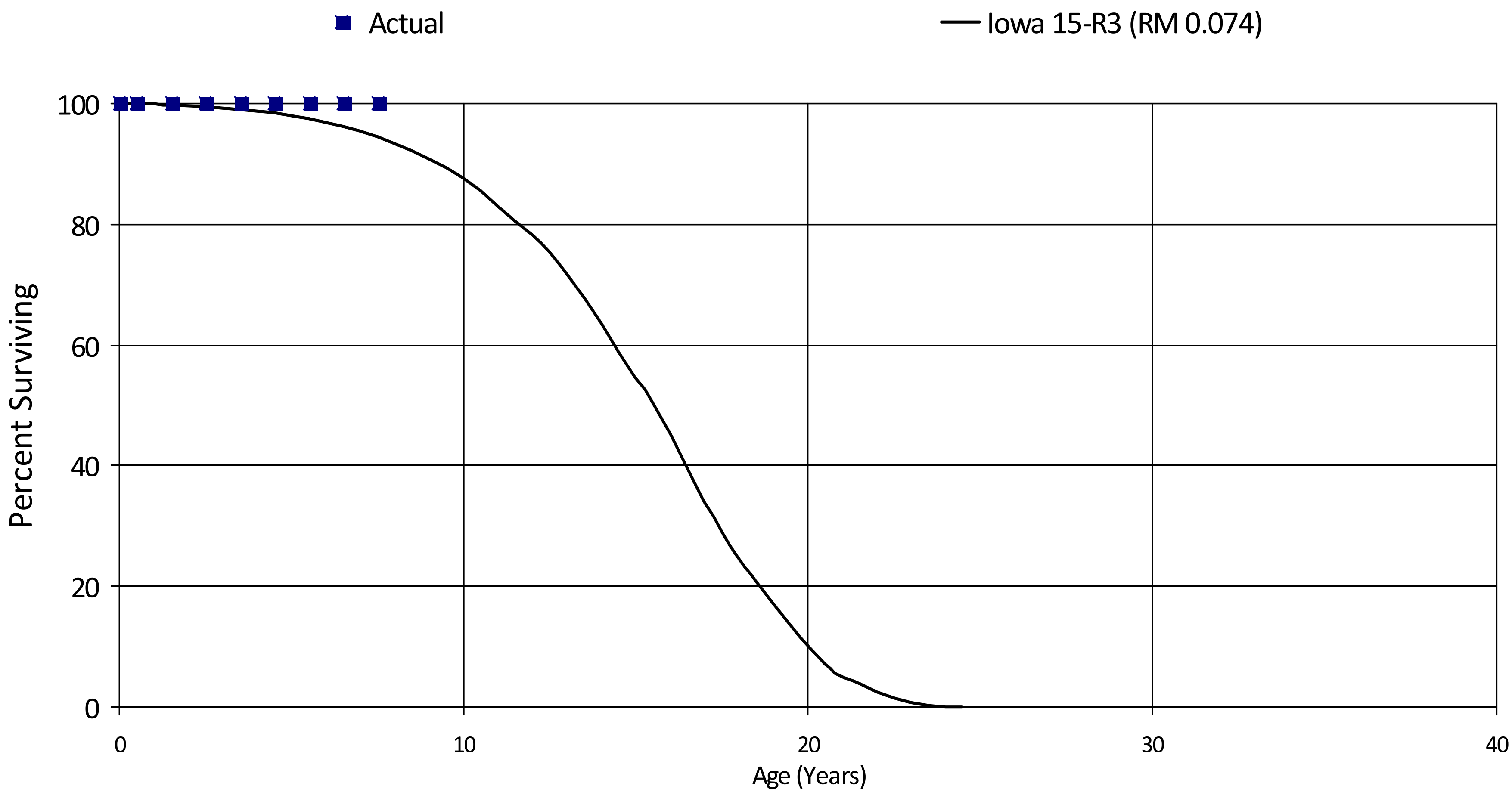
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	42,072	0	0.00000	1.00000	100.00
0.5	42,072	0	0.00000	1.00000	100.00
1.5	42,072	0	0.00000	1.00000	100.00
2.5	42,072	0	0.00000	1.00000	100.00
3.5	42,072	0	0.00000	1.00000	100.00
4.5	42,072	0	0.00000	1.00000	100.00
5.5	42,072	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 30610 - Control System, Fuel

Placement Band - 2001 - 2012   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 30610 - Control System, Fuel

Placement Band - 2001 - 2012 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

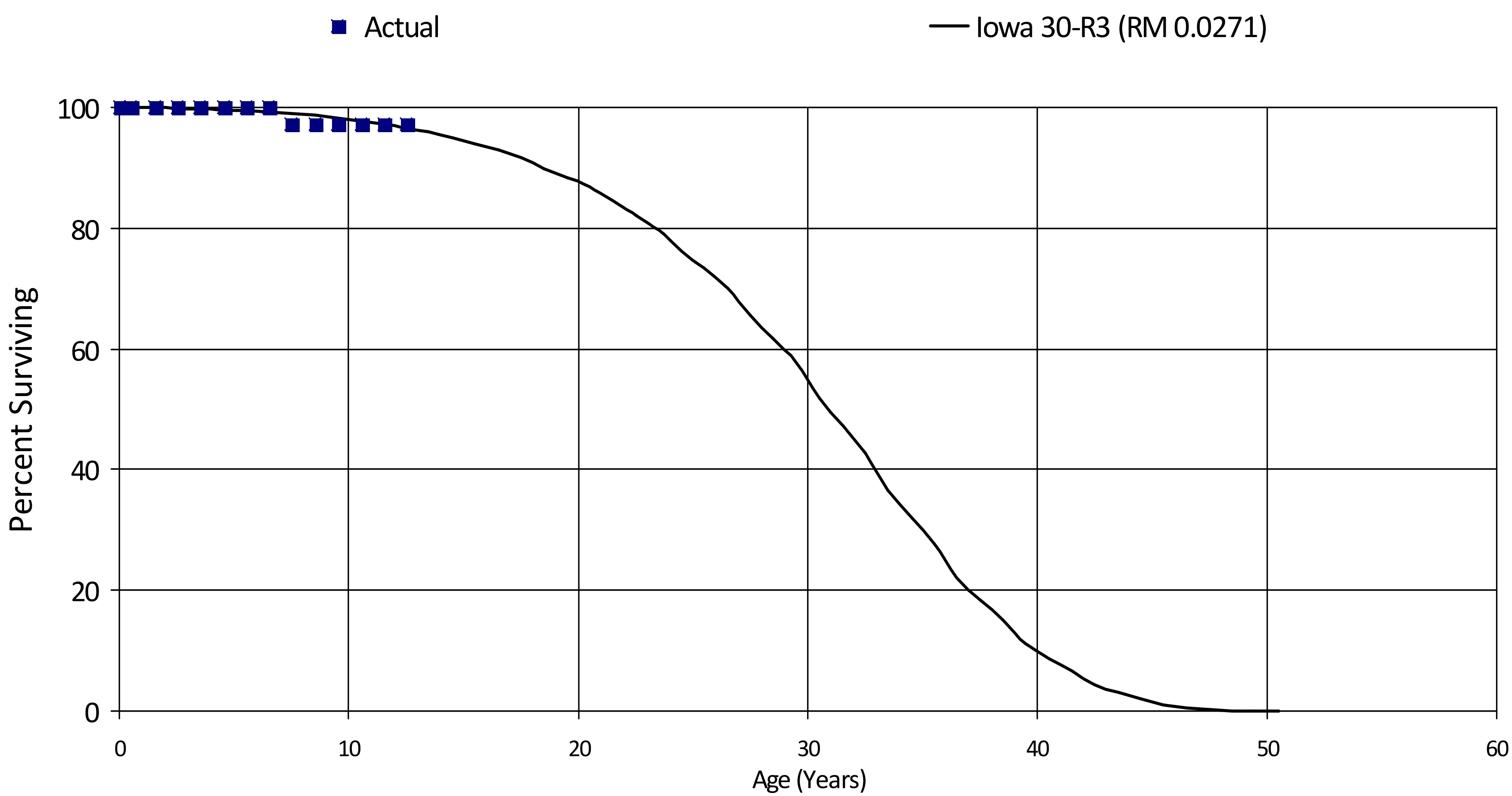
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,968,702	0	0.00000	1.00000	100.00
0.5	2,968,702	0	0.00000	1.00000	100.00
1.5	2,968,702	0	0.00000	1.00000	100.00
2.5	2,968,702	0	0.00000	1.00000	100.00
3.5	2,968,702	0	0.00000	1.00000	100.00
4.5	2,968,702	0	0.00000	1.00000	100.00
5.5	2,968,702	0	0.00000	1.00000	100.00
6.5	2,968,702	0	0.00000	1.00000	100.00
7.5	2,968,702	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 30613 - Boiler, Package

Placement Band - 1999 - 2012 Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 30613 - Boiler, Package

Placement Band - 1999 - 2012   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

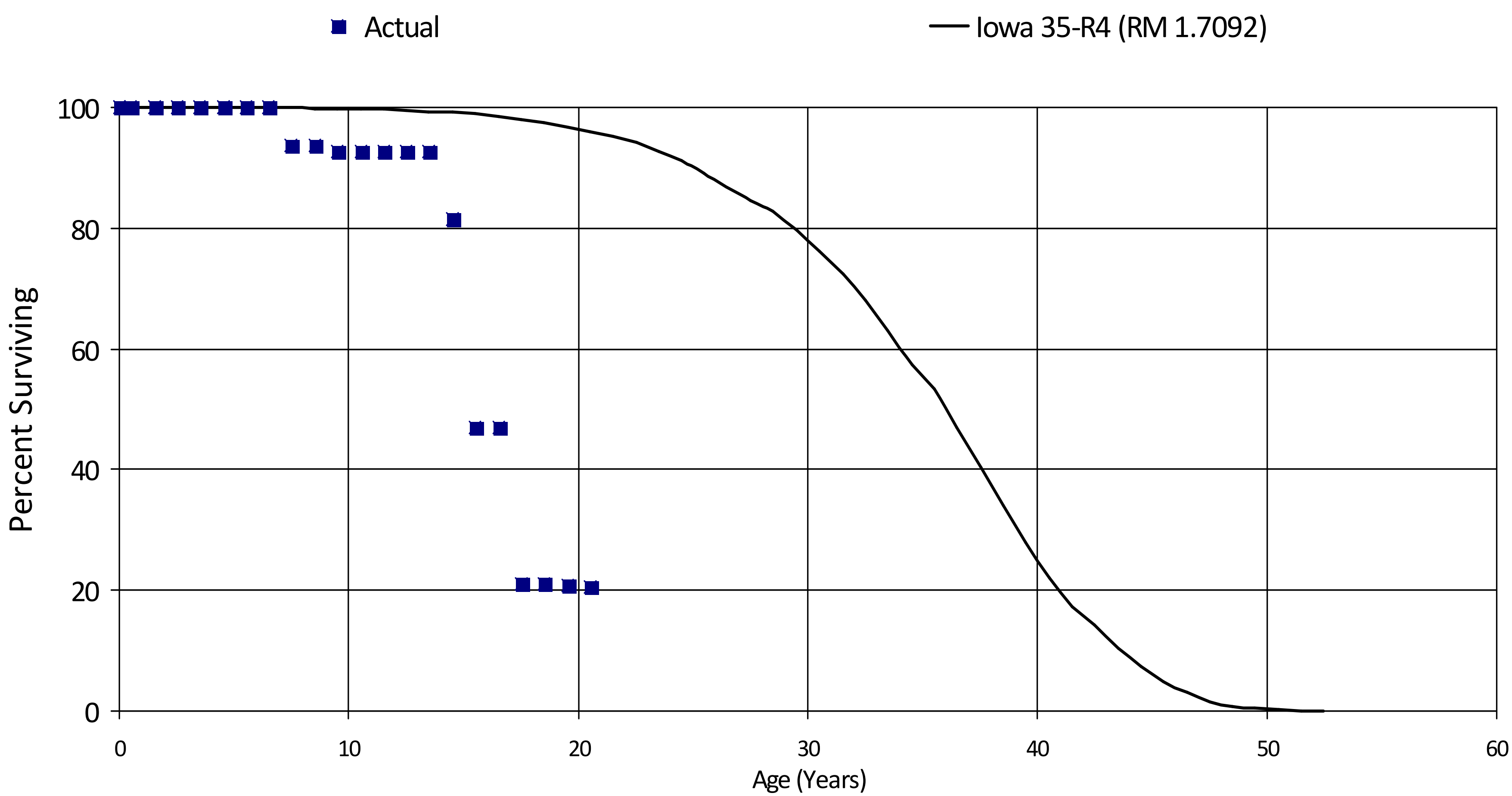
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	20,227,793	0	0.00000	1.00000	100.00
0.5	20,227,793	0	0.00000	1.00000	100.00
1.5	20,227,793	0	0.00000	1.00000	100.00
2.5	20,227,793	0	0.00000	1.00000	100.00
3.5	20,227,793	0	0.00000	1.00000	100.00
4.5	20,227,793	0	0.00000	1.00000	100.00
5.5	20,227,793	0	0.00000	1.00000	100.00
6.5	20,227,793	547,000	0.02704	0.97296	100.00
7.5	19,680,793	0	0.00000	1.00000	97.30
8.5	2,418,113	0	0.00000	1.00000	97.30
9.5	2,418,113	0	0.00000	1.00000	97.30
10.5	2,418,113	0	0.00000	1.00000	97.30
11.5	2,418,113	0	0.00000	1.00000	97.30
12.5	2,418,113	2,418,113	1.00000		97.30
	Totals:	2,965,113			

BC Hydro Power Authority

Account 30701 - Equipment, Water Treatment

Placement Band - 1994 - 2018 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 30701 - Equipment, Water Treatment

Placement Band - 1994 - 2018   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

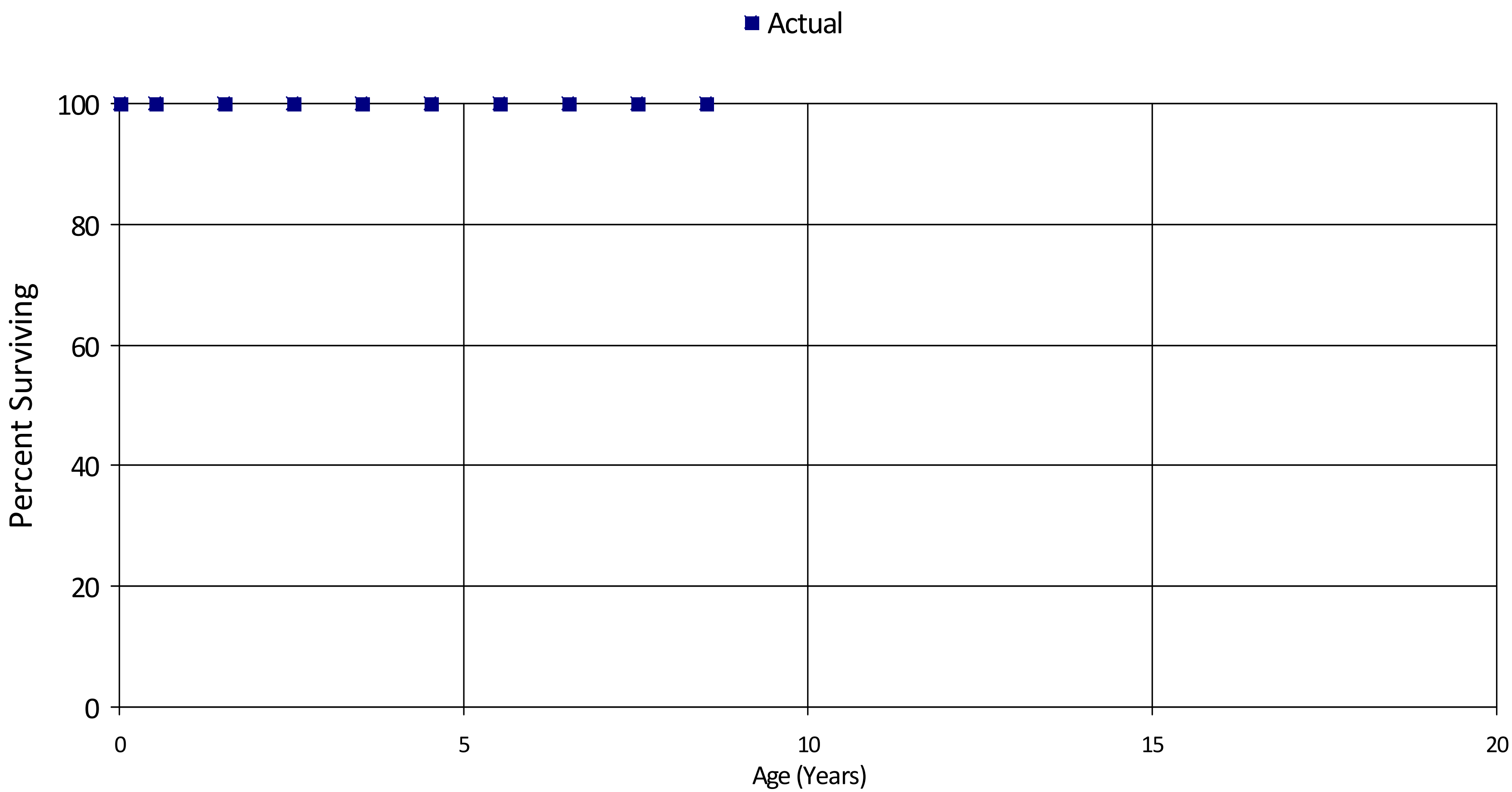
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	12,045,396	0	0.00000	1.00000	100.00
0.5	12,045,396	0	0.00000	1.00000	100.00
1.5	12,045,396	0	0.00000	1.00000	100.00
2.5	8,725,941	0	0.00000	1.00000	100.00
3.5	6,945,713	0	0.00000	1.00000	100.00
4.5	6,945,713	0	0.00000	1.00000	100.00
5.5	6,945,713	0	0.00000	1.00000	100.00
6.5	6,945,713	445,748	0.06418	0.93582	100.00
7.5	6,499,965	0	0.00000	1.00000	93.58
8.5	6,499,965	59,688	0.00918	0.99082	93.58
9.5	6,440,277	0	0.00000	1.00000	92.72
10.5	6,440,277	0	0.00000	1.00000	92.72
11.5	6,440,277	0	0.00000	1.00000	92.72
12.5	6,440,277	0	0.00000	1.00000	92.72
13.5	6,440,277	789,903	0.12265	0.87735	92.72
14.5	5,650,374	2,391,996	0.42333	0.57667	81.35
15.5	3,258,379	0	0.00000	1.00000	46.91
16.5	3,258,379	1,803,248	0.55342	0.44658	46.91
17.5	1,367,113	0	0.00000	1.00000	20.95
18.5	1,367,113	1,581	0.00116	0.99884	20.95
19.5	1,365,532	20,453	0.01498	0.98502	20.93
20.5	1,345,080	0	0.00000	1.00000	20.62
	Totals:	5,512,617			

BC Hydro Power Authority

Account 30901 - Monitoring Equip., Cem

Placement Band - 1996 - 2019   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 30901 - Monitoring Equip., Cem

Placement Band - 1996 - 2019   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

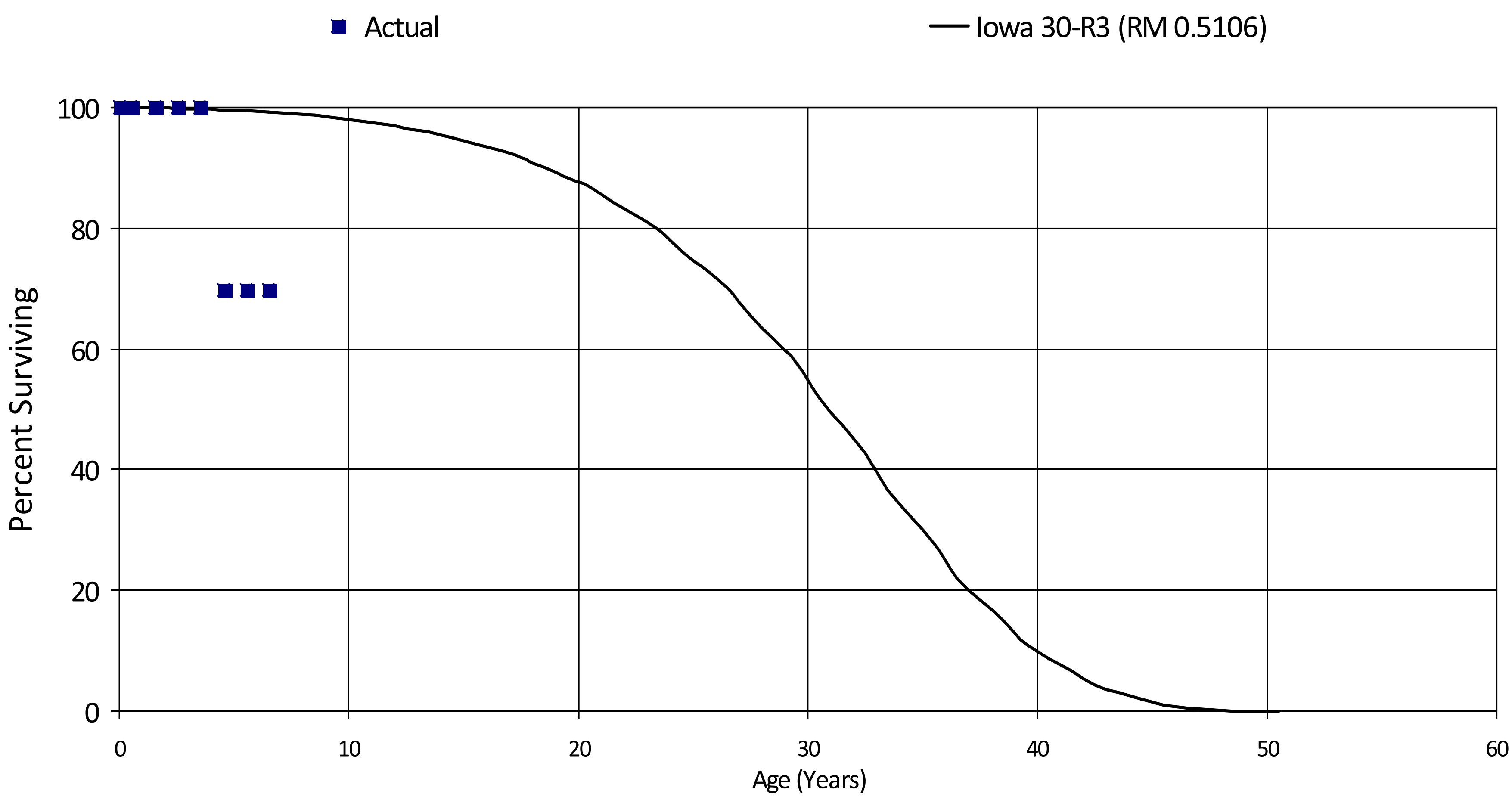
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	7,052,411	0	0.00000	1.00000	100.00
0.5	7,052,411	0	0.00000	1.00000	100.00
1.5	2,405,289	0	0.00000	1.00000	100.00
2.5	2,349,035	0	0.00000	1.00000	100.00
3.5	2,349,035	0	0.00000	1.00000	100.00
4.5	2,349,035	0	0.00000	1.00000	100.00
5.5	2,349,035	0	0.00000	1.00000	100.00
6.5	2,349,035	0	0.00000	1.00000	100.00
7.5	2,349,035	0	0.00000	1.00000	100.00
8.5	153,279	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 31003 - Gates, Inlet / Outlet

Placement Band - 2002 - 2019   Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 31003 - Gates, Inlet / Outlet

Placement Band - 2002 - 2019   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

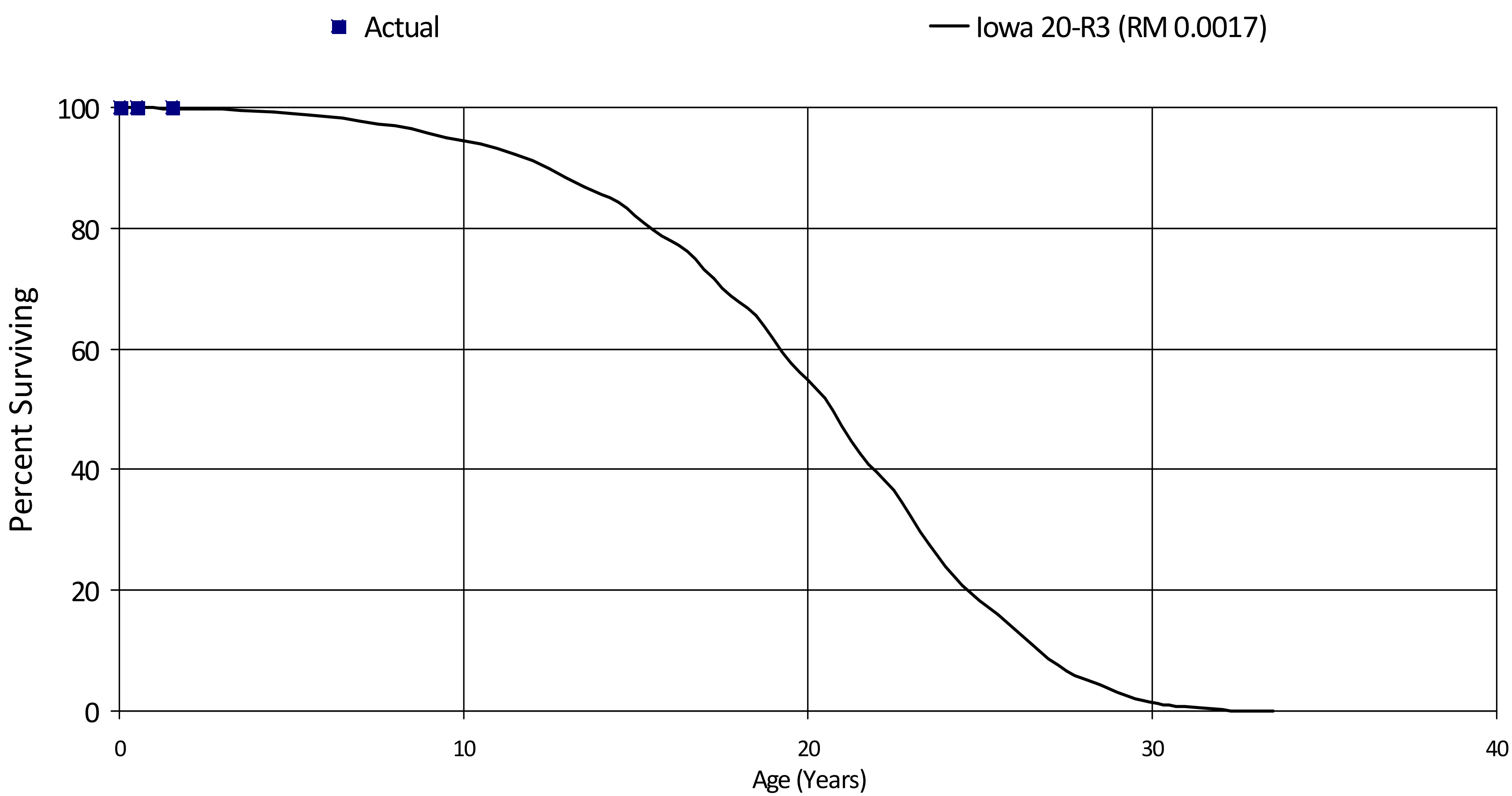
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	11,890,175	0	0.00000	1.00000	100.00
0.5	11,890,175	0	0.00000	1.00000	100.00
1.5	11,837,714	0	0.00000	1.00000	100.00
2.5	11,837,714	0	0.00000	1.00000	100.00
3.5	11,837,714	3,561,848	0.30089	0.69911	100.00
4.5	8,239,954	0	0.00000	1.00000	69.91
5.5	346,981	0	0.00000	1.00000	69.91
6.5	346,981	0	0.00000	1.00000	69.91
	Totals:	3,561,848			

BC Hydro Power Authority

Account 31004 - Screens, Intake

Placement Band - 1989 - 2018 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 31004 - Screens, Intake

Placement Band - 1989 - 2018   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

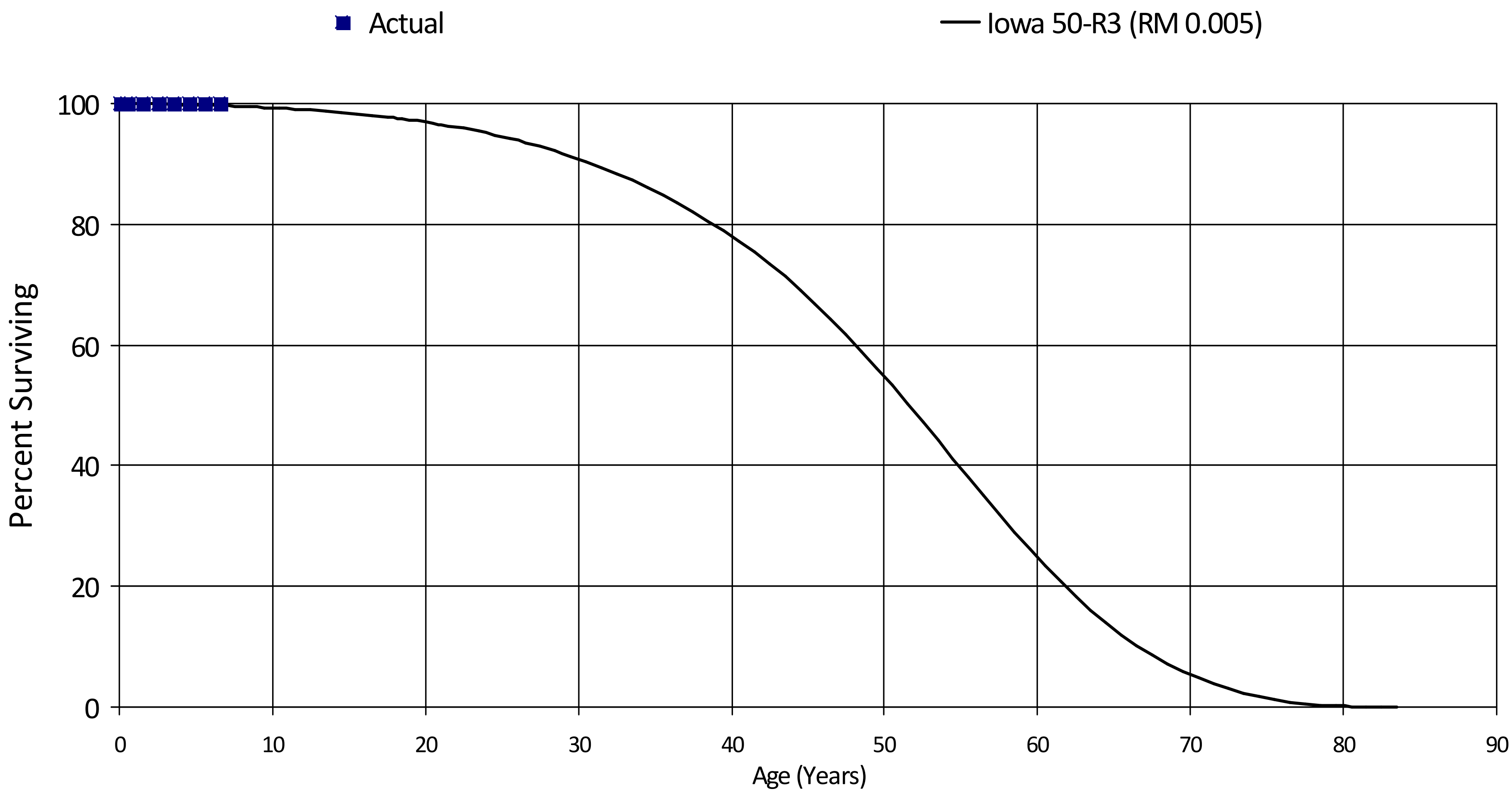
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	338,337	0	0.00000	1.00000	100.00
0.5	338,337	0	0.00000	1.00000	100.00
1.5	338,337	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 31005 - Conduit, Intake / Discharge

Placement Band - 2001 - 2013   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 31005 - Conduit, Intake / Discharge

Placement Band - 2001 - 2013 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

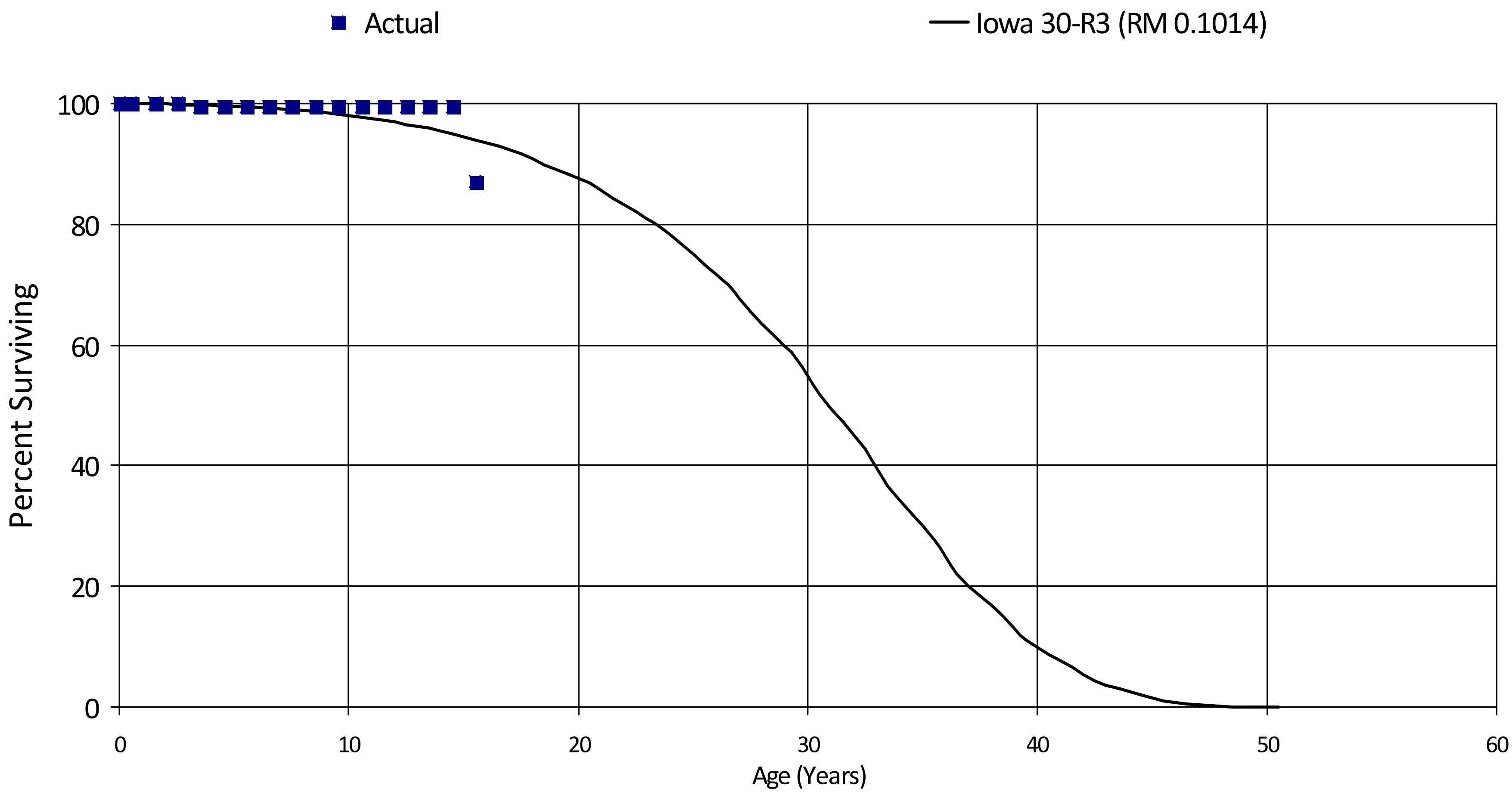
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,764,855	0	0.00000	1.00000	100.00
0.5	2,764,855	0	0.00000	1.00000	100.00
1.5	2,764,855	0	0.00000	1.00000	100.00
2.5	2,764,855	0	0.00000	1.00000	100.00
3.5	2,764,855	0	0.00000	1.00000	100.00
4.5	2,764,855	0	0.00000	1.00000	100.00
5.5	2,764,855	0	0.00000	1.00000	100.00
6.5	2,764,855	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 31006 - Valves

Placement Band - 1996 - 2019   Experience Band - 2015 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 31006 - Valves

Placement Band - 1996 - 2019   Experience Band - 2015 - 2020

RETIREMENT RATE ANALYSIS

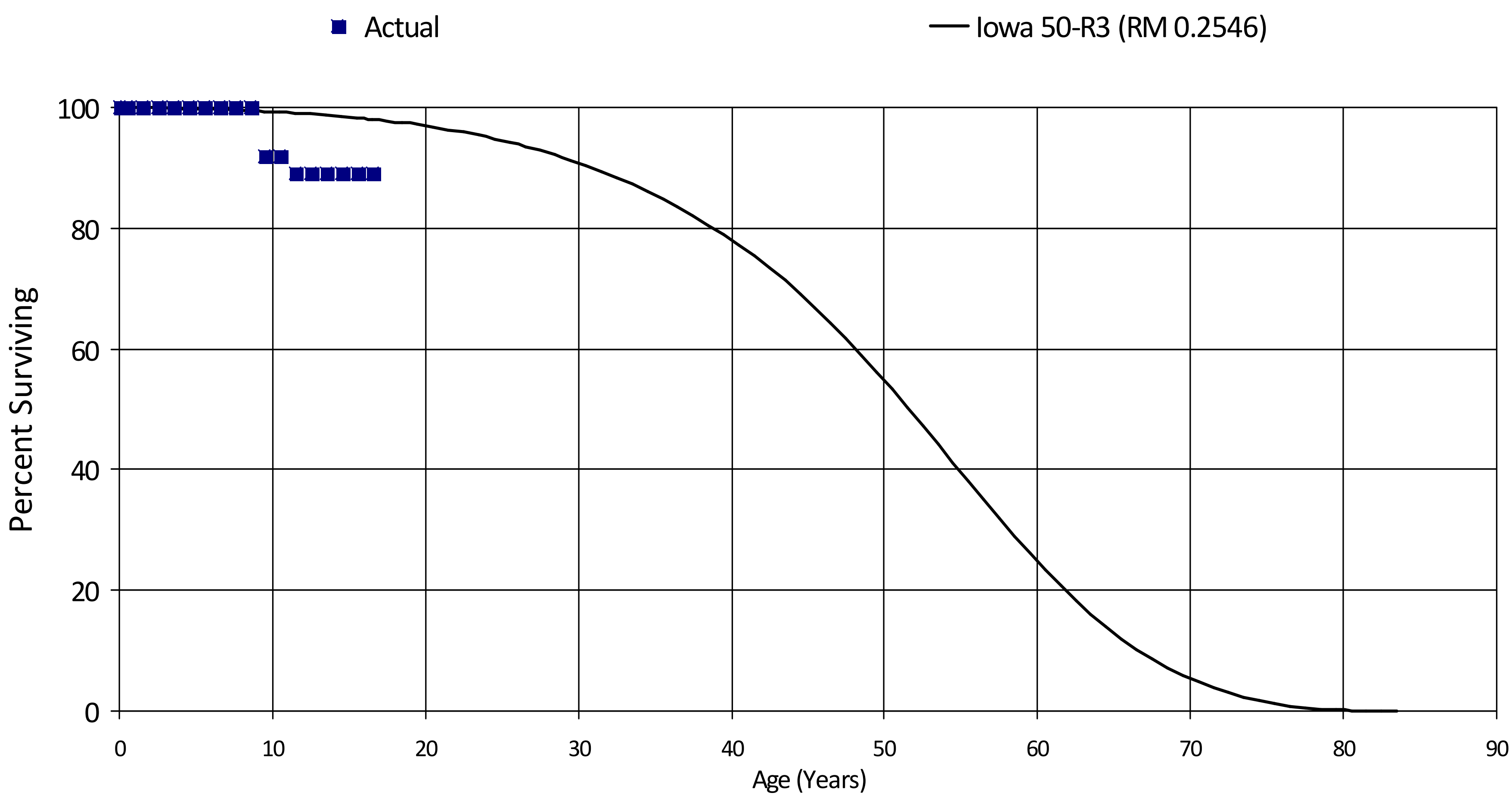
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	15,286,900	0	0.00000	1.00000	100.00
0.5	15,286,900	0	0.00000	1.00000	100.00
1.5	13,427,378	0	0.00000	1.00000	100.00
2.5	13,427,378	56,000	0.00417	0.99583	100.00
3.5	12,763,873	0	0.00000	1.00000	99.58
4.5	11,836,491	0	0.00000	1.00000	99.58
5.5	9,135,608	0	0.00000	1.00000	99.58
6.5	8,885,091	0	0.00000	1.00000	99.58
7.5	7,504,411	0	0.00000	1.00000	99.58
8.5	5,353,218	0	0.00000	1.00000	99.58
9.5	5,253,307	0	0.00000	1.00000	99.58
10.5	4,684,528	0	0.00000	1.00000	99.58
11.5	4,654,155	0	0.00000	1.00000	99.58
12.5	608,671	0	0.00000	1.00000	99.58
13.5	487,355	0	0.00000	1.00000	99.58
14.5	383,466	48,299	0.12595	0.87405	99.58
15.5	194,880	0	0.00000	1.00000	87.04
	Totals:	104,299			

BC Hydro Power Authority

Account 31007 - Turbine / Penstock Inlet Valves

Placement Band - 2003 - 2019   Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 31007 - Turbine / Penstock Inlet Valves

Placement Band - 2003 - 2019   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

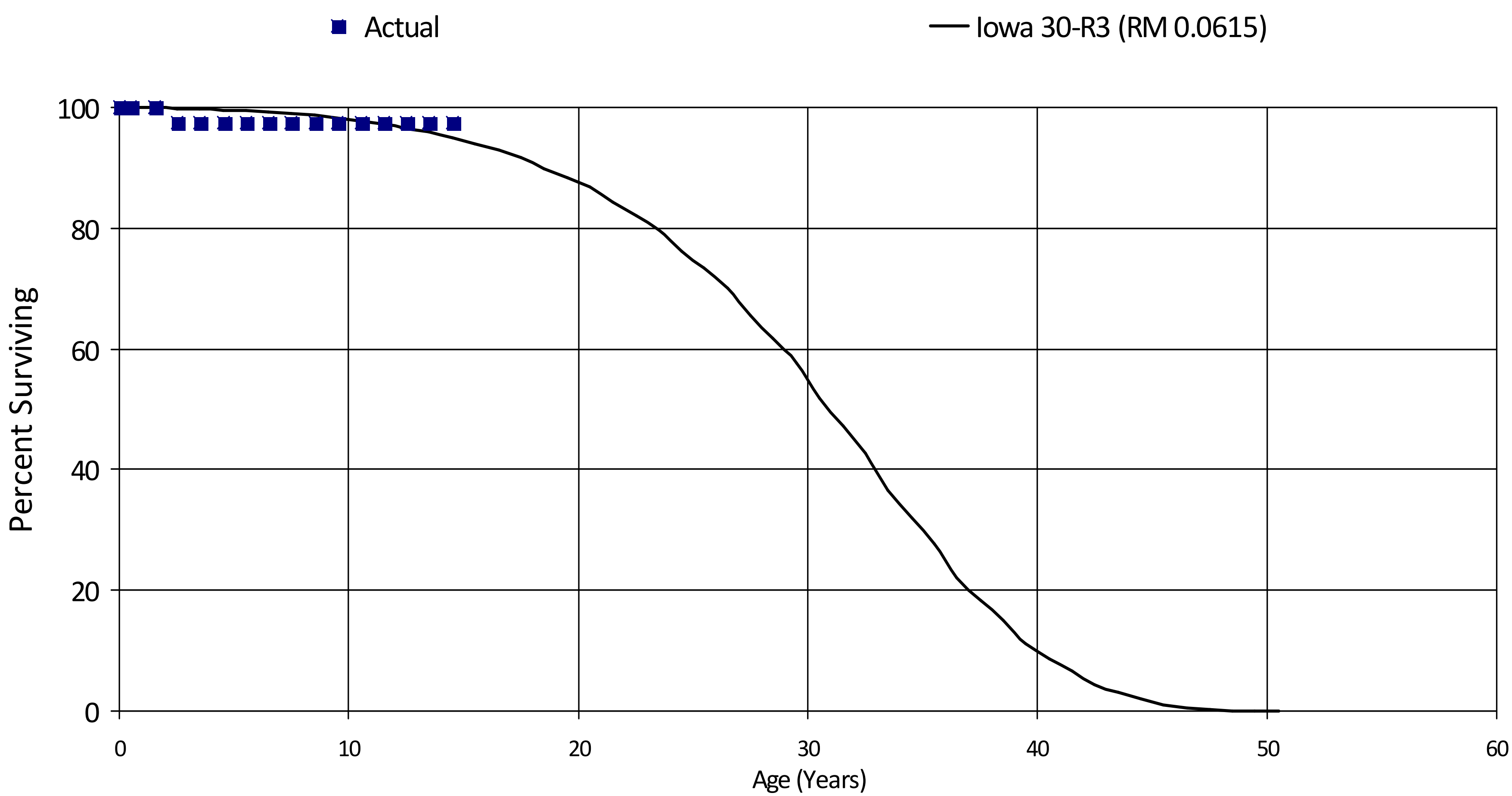
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	12,862,060	0	0.00000	1.00000	100.00
0.5	12,862,060	0	0.00000	1.00000	100.00
1.5	12,231,479	0	0.00000	1.00000	100.00
2.5	12,231,479	0	0.00000	1.00000	100.00
3.5	12,231,479	0	0.00000	1.00000	100.00
4.5	11,555,083	0	0.00000	1.00000	100.00
5.5	10,329,906	0	0.00000	1.00000	100.00
6.5	10,329,906	0	0.00000	1.00000	100.00
7.5	10,329,906	0	0.00000	1.00000	100.00
8.5	10,329,906	829,340	0.08029	0.91971	100.00
9.5	6,907,241	0	0.00000	1.00000	91.97
10.5	6,751,783	209,224	0.03099	0.96901	91.97
11.5	2,949,410	0	0.00000	1.00000	89.12
12.5	2,949,410	0	0.00000	1.00000	89.12
13.5	2,708,262	0	0.00000	1.00000	89.12
14.5	2,689,135	0	0.00000	1.00000	89.12
15.5	1,128,521	0	0.00000	1.00000	89.12
16.5	934,913	0	0.00000	1.00000	89.12
	Totals:	1,038,564			

BC Hydro Power Authority

Account 33002 - Pump And Motor

Placement Band - 1963 - 2019 Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 33002 - Pump And Motor

Placement Band - 1963 - 2019   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

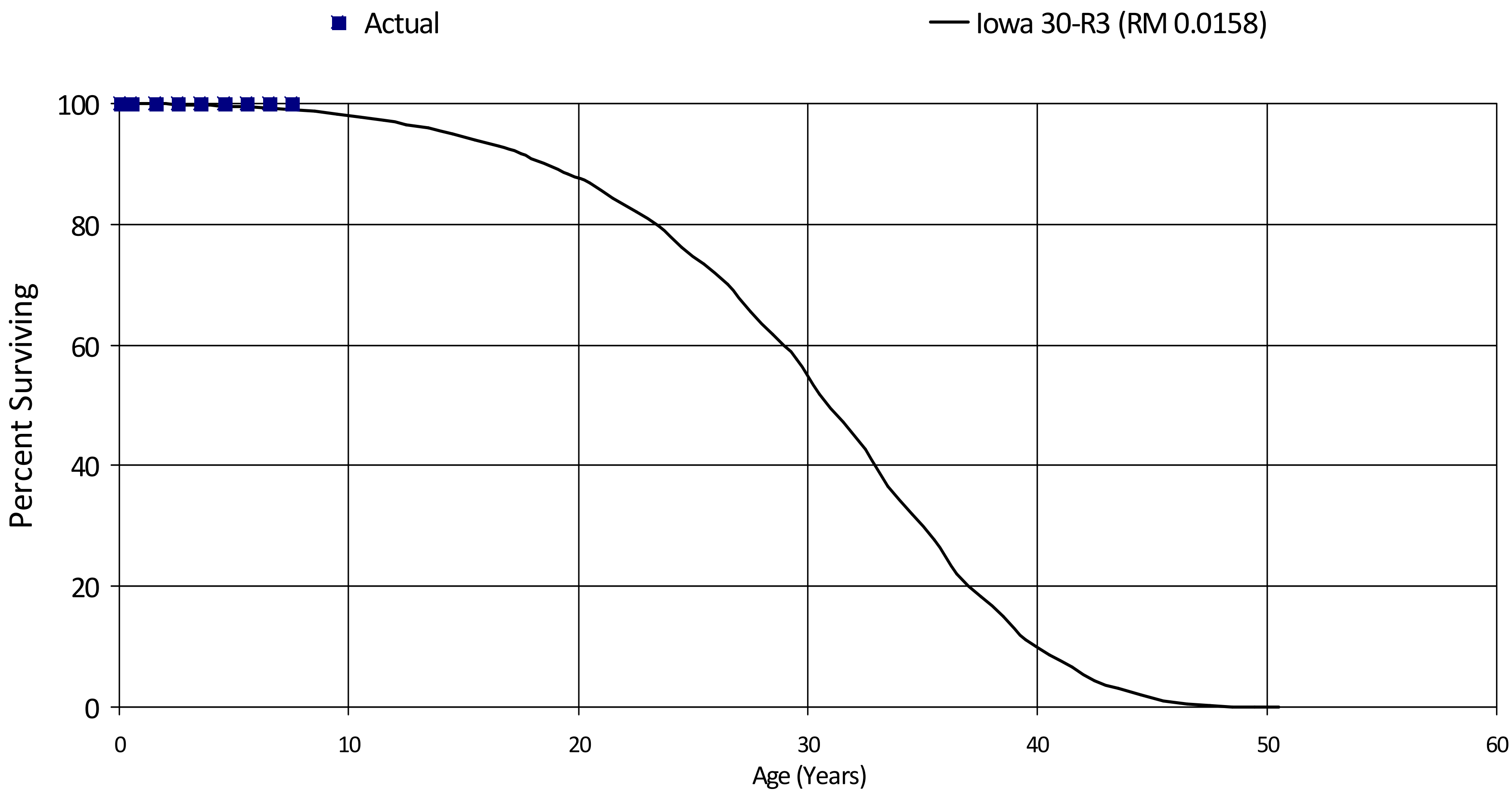
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,623,477	0	0.00000	1.00000	100.00
0.5	1,623,477	0	0.00000	1.00000	100.00
1.5	590,419	15,707	0.02660	0.97340	100.00
2.5	574,713	0	0.00000	1.00000	97.34
3.5	532,396	0	0.00000	1.00000	97.34
4.5	401,166	0	0.00000	1.00000	97.34
5.5	224,660	0	0.00000	1.00000	97.34
6.5	141,410	0	0.00000	1.00000	97.34
7.5	16,912	0	0.00000	1.00000	97.34
8.5	16,912	0	0.00000	1.00000	97.34
9.5	16,912	0	0.00000	1.00000	97.34
10.5	16,912	0	0.00000	1.00000	97.34
11.5	16,912	0	0.00000	1.00000	97.34
12.5	16,912	0	0.00000	1.00000	97.34
13.5	16,912	0	0.00000	1.00000	97.34
14.5	16,912	0	0.00000	1.00000	97.34
	Totals:	15,707			

BC Hydro Power Authority

Account 33004 - Condenser, Boiler

Placement Band - 2002 - 2012 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 33004 - Condenser, Boiler

Placement Band - 2002 - 2012   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

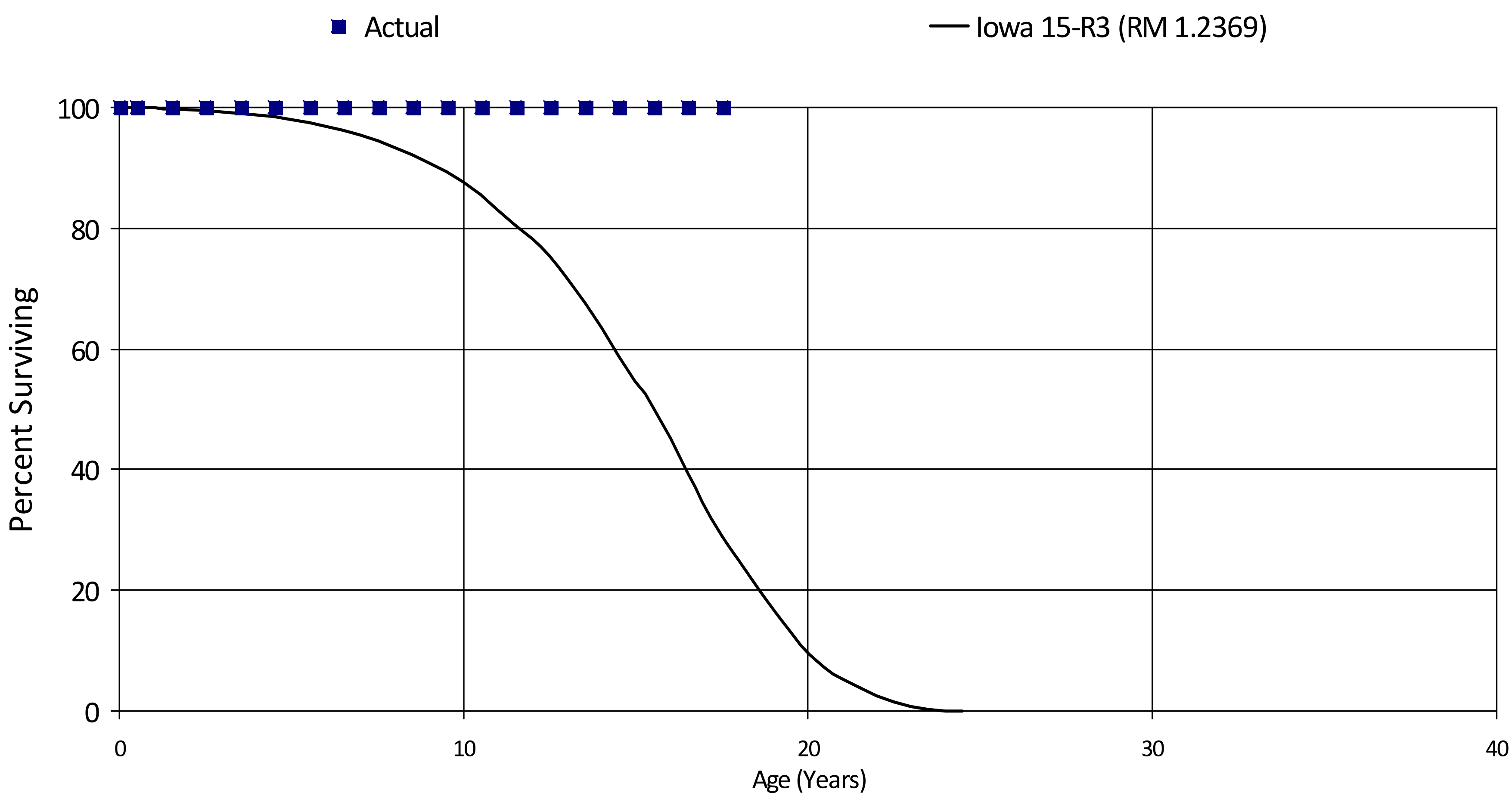
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	5,898,240	0	0.00000	1.00000	100.00
0.5	5,898,240	0	0.00000	1.00000	100.00
1.5	5,898,240	0	0.00000	1.00000	100.00
2.5	5,898,240	0	0.00000	1.00000	100.00
3.5	5,898,240	0	0.00000	1.00000	100.00
4.5	5,898,240	0	0.00000	1.00000	100.00
5.5	5,898,240	0	0.00000	1.00000	100.00
6.5	5,898,240	0	0.00000	1.00000	100.00
7.5	5,898,240	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 33005 - Condenser Air Removal System

Placement Band - 2002 - 2002 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 33005 - Condenser Air Removal System

Placement Band - 2002 - 2002   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

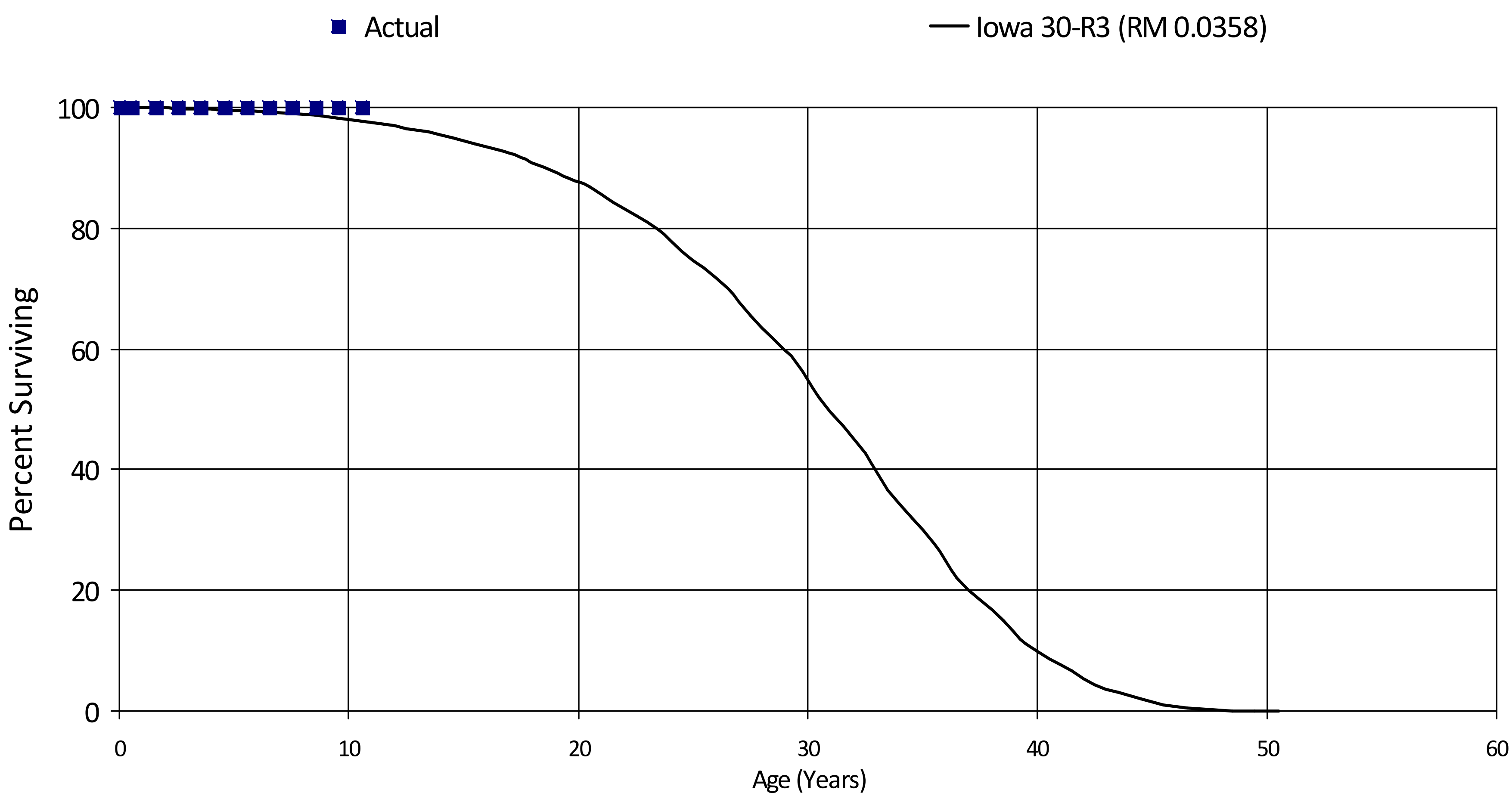
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	325	0	0.00000	1.00000	100.00
0.5	325	0	0.00000	1.00000	100.00
1.5	325	0	0.00000	1.00000	100.00
2.5	325	0	0.00000	1.00000	100.00
3.5	325	0	0.00000	1.00000	100.00
4.5	325	0	0.00000	1.00000	100.00
5.5	325	0	0.00000	1.00000	100.00
6.5	325	0	0.00000	1.00000	100.00
7.5	325	0	0.00000	1.00000	100.00
8.5	325	0	0.00000	1.00000	100.00
9.5	325	0	0.00000	1.00000	100.00
10.5	325	0	0.00000	1.00000	100.00
11.5	325	0	0.00000	1.00000	100.00
12.5	325	0	0.00000	1.00000	100.00
13.5	325	0	0.00000	1.00000	100.00
14.5	325	0	0.00000	1.00000	100.00
15.5	325	0	0.00000	1.00000	100.00
16.5	325	0	0.00000	1.00000	100.00
17.5	325	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 34002 - Casing, Cylinder

Placement Band - 2002 - 2012   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 34002 - Casing, Cylinder

Placement Band - 2002 - 2012   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

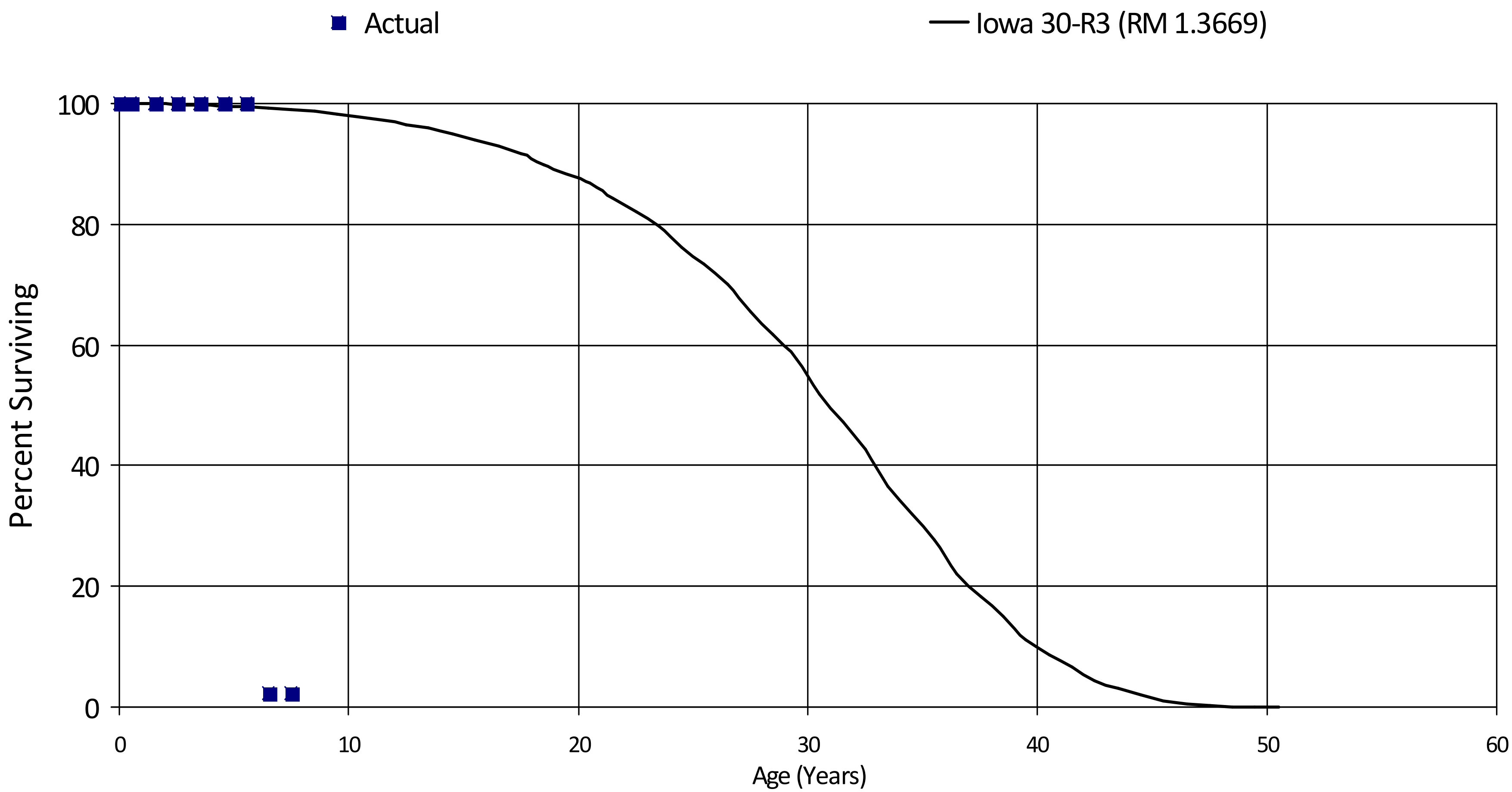
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	4,642,065	0	0.00000	1.00000	100.00
0.5	4,642,065	0	0.00000	1.00000	100.00
1.5	4,642,065	0	0.00000	1.00000	100.00
2.5	4,642,065	0	0.00000	1.00000	100.00
3.5	4,642,065	0	0.00000	1.00000	100.00
4.5	4,642,065	0	0.00000	1.00000	100.00
5.5	4,642,065	0	0.00000	1.00000	100.00
6.5	4,642,065	0	0.00000	1.00000	100.00
7.5	4,642,065	0	0.00000	1.00000	100.00
8.5	1,576,488	0	0.00000	1.00000	100.00
9.5	1,576,488	0	0.00000	1.00000	100.00
10.5	1,576,488	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 34004 - Turbine, Composite Pool

Placement Band - 2001 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 34004 - Turbine, Composite Pool

Placement Band - 2001 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

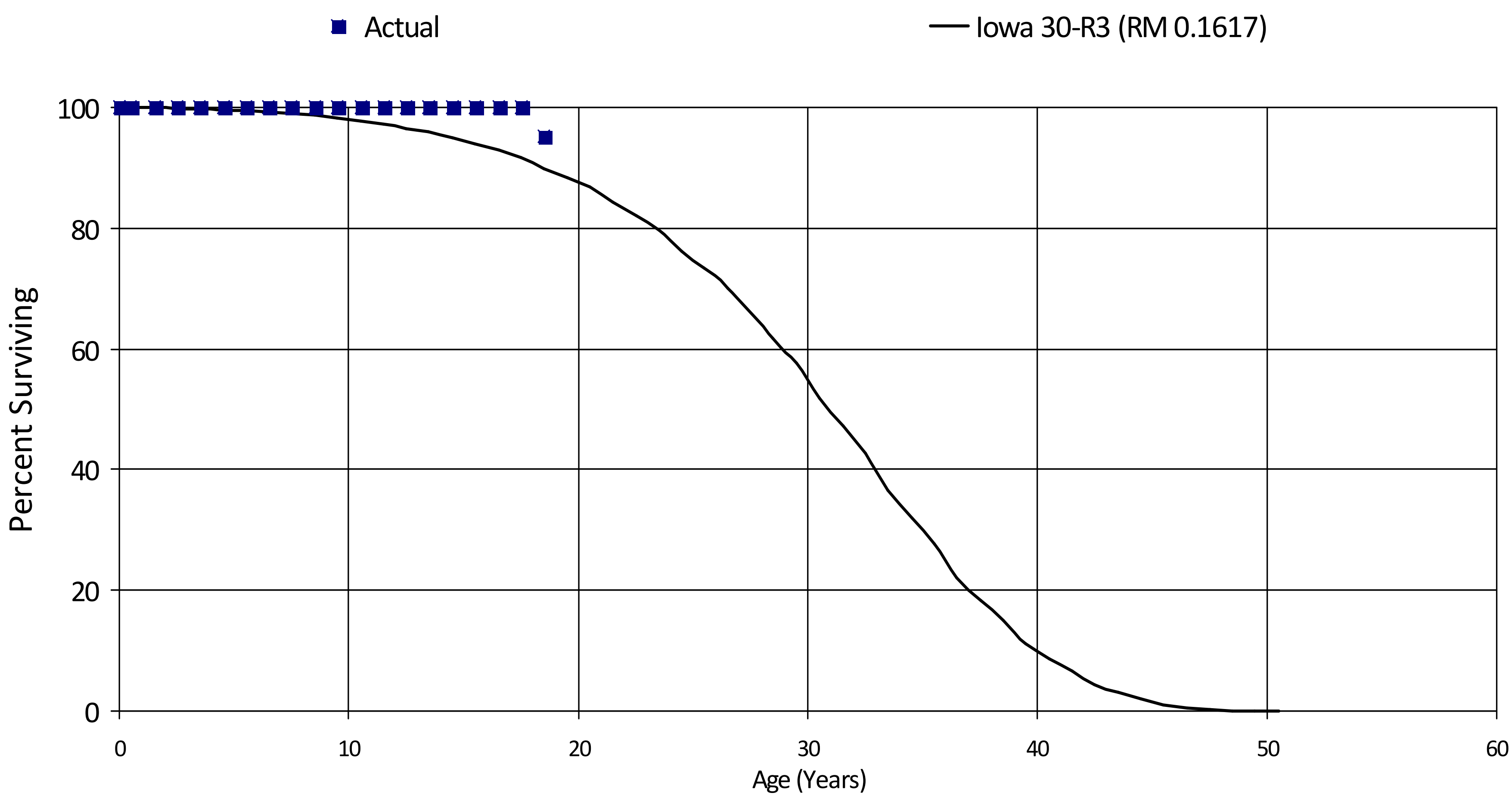
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	168,084,599	0	0.00000	1.00000	100.00
0.5	167,780,207	0	0.00000	1.00000	100.00
1.5	167,780,207	0	0.00000	1.00000	100.00
2.5	167,780,207	-97,851	-0.00058	1.00058	100.00
3.5	167,878,057	0	0.00000	1.00000	100.06
4.5	167,456,705	0	0.00000	1.00000	100.06
5.5	167,456,705	163,460,000	0.97613	0.02387	100.06
6.5	3,801,424	0	0.00000	1.00000	2.39
7.5	3,801,424	0	0.00000	1.00000	2.39
	Totals:	163,362,149			

BC Hydro Power Authority

Account 34005 - Coils, Stator

Placement Band - 1993 - 2012   Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 34005 - Coils, Stator

Placement Band - 1993 - 2012   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

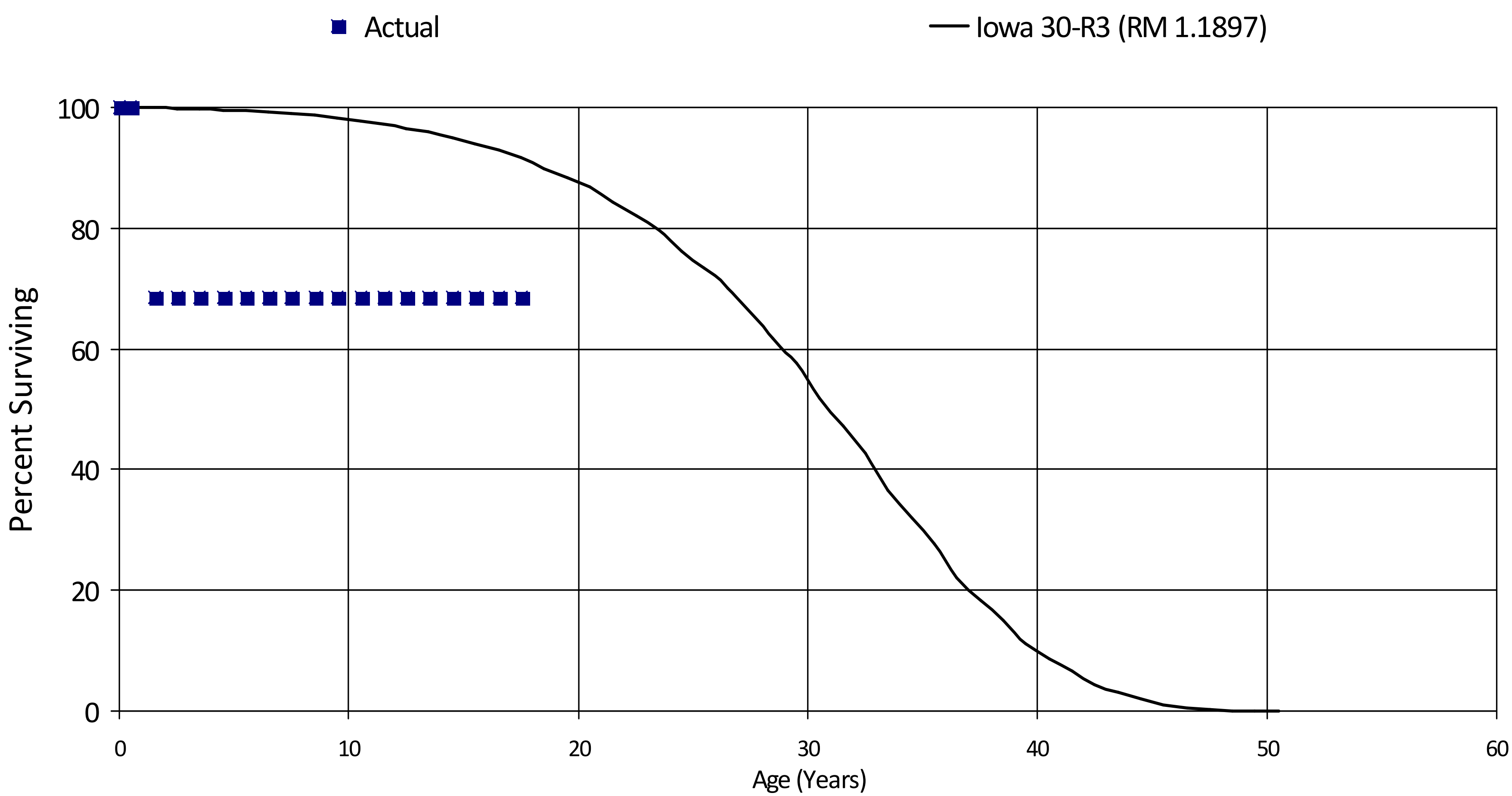
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	4,489,480	0	0.00000	1.00000	100.00
0.5	4,489,480	0	0.00000	1.00000	100.00
1.5	4,489,480	0	0.00000	1.00000	100.00
2.5	4,489,480	0	0.00000	1.00000	100.00
3.5	4,489,480	0	0.00000	1.00000	100.00
4.5	4,489,480	0	0.00000	1.00000	100.00
5.5	4,489,480	0	0.00000	1.00000	100.00
6.5	4,489,480	0	0.00000	1.00000	100.00
7.5	4,489,480	0	0.00000	1.00000	100.00
8.5	2,044,515	0	0.00000	1.00000	100.00
9.5	2,044,515	0	0.00000	1.00000	100.00
10.5	2,044,515	0	0.00000	1.00000	100.00
11.5	2,044,515	0	0.00000	1.00000	100.00
12.5	2,044,515	0	0.00000	1.00000	100.00
13.5	2,044,515	0	0.00000	1.00000	100.00
14.5	2,044,515	0	0.00000	1.00000	100.00
15.5	2,044,515	0	0.00000	1.00000	100.00
16.5	2,044,515	0	0.00000	1.00000	100.00
17.5	2,044,515	99,518	0.04868	0.95132	100.00
18.5	58,325	0	0.00000	1.00000	95.13
	Totals:	99,518			

BC Hydro Power Authority

Account 34006 - Rotor, Generator

Placement Band - 1993 - 2016 Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 34006 - Rotor, Generator

Placement Band - 1993 - 2016 Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

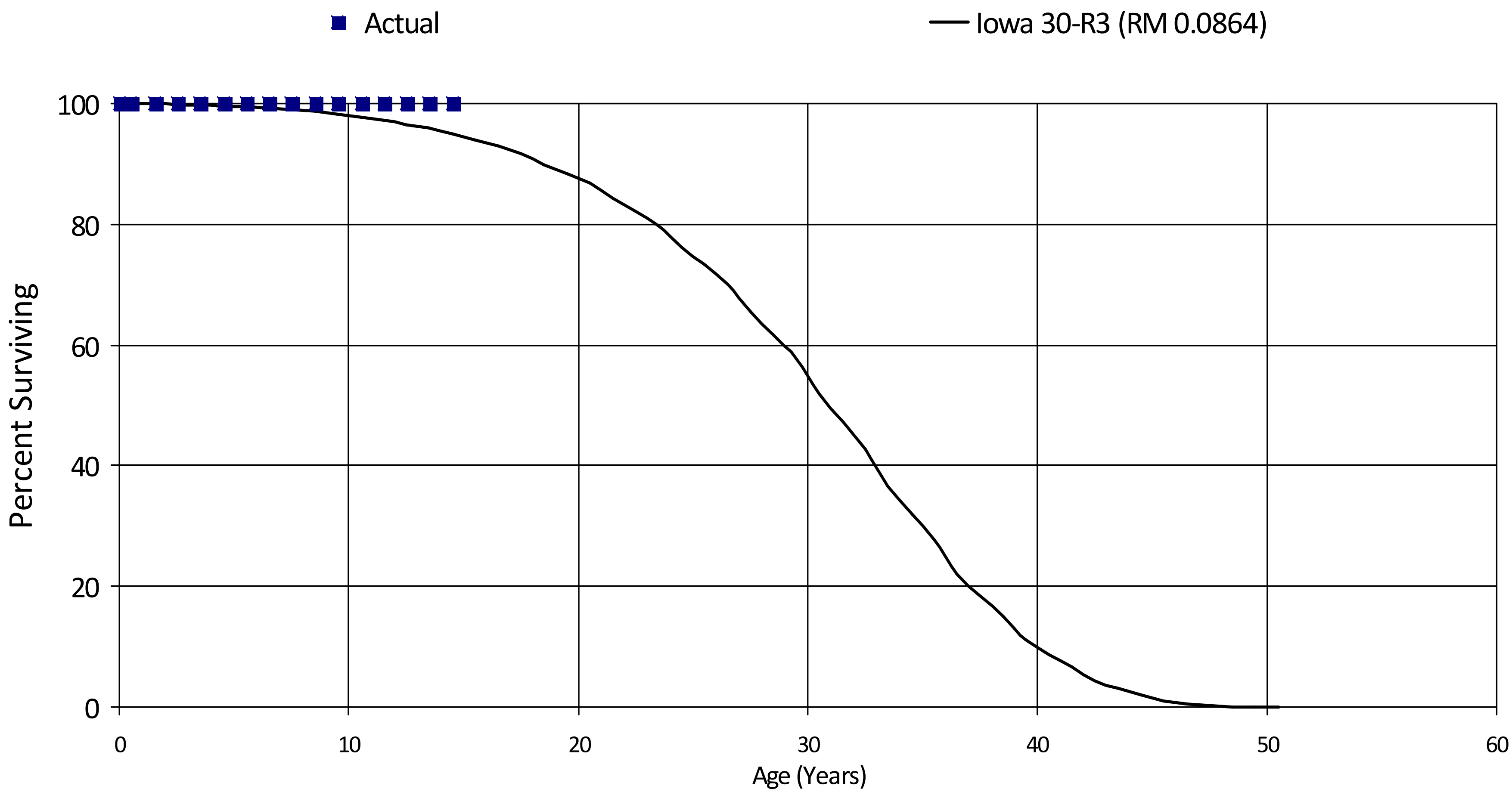
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	8,551,820	0	0.00000	1.00000	100.00
0.5	8,551,820	2,689,712	0.31452	0.68548	100.00
1.5	5,862,107	0	0.00000	1.00000	68.55
2.5	5,862,107	0	0.00000	1.00000	68.55
3.5	5,862,107	0	0.00000	1.00000	68.55
4.5	5,862,107	0	0.00000	1.00000	68.55
5.5	5,862,107	0	0.00000	1.00000	68.55
6.5	5,862,107	0	0.00000	1.00000	68.55
7.5	5,862,107	0	0.00000	1.00000	68.55
8.5	1,111,950	0	0.00000	1.00000	68.55
9.5	1,111,950	0	0.00000	1.00000	68.55
10.5	1,111,950	0	0.00000	1.00000	68.55
11.5	1,111,950	0	0.00000	1.00000	68.55
12.5	1,111,950	0	0.00000	1.00000	68.55
13.5	1,111,950	0	0.00000	1.00000	68.55
14.5	1,111,950	0	0.00000	1.00000	68.55
15.5	1,111,950	0	0.00000	1.00000	68.55
16.5	1,111,950	0	0.00000	1.00000	68.55
17.5	1,111,950	0	0.00000	1.00000	68.55
	Totals:	2,689,712			

BC Hydro Power Authority

Account 34007 - Generator, Composite Pool

Placement Band - 1969 - 2017 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 34007 - Generator, Composite Pool

Placement Band - 1969 - 2017 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

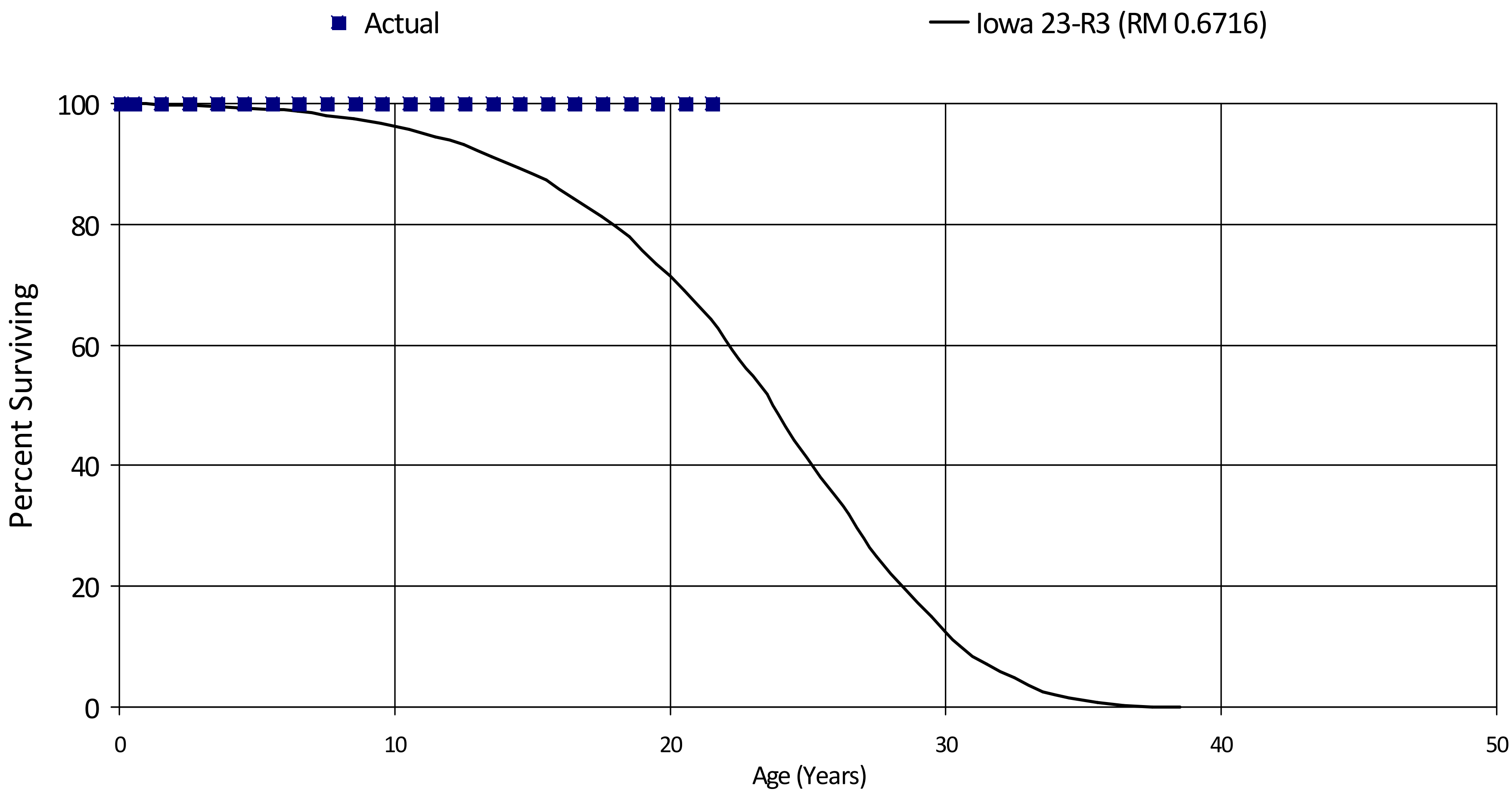
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,271,580	0	0.00000	1.00000	100.00
0.5	2,271,580	0	0.00000	1.00000	100.00
1.5	2,271,580	0	0.00000	1.00000	100.00
2.5	2,271,580	0	0.00000	1.00000	100.00
3.5	2,012,646	0	0.00000	1.00000	100.00
4.5	1,831,722	0	0.00000	1.00000	100.00
5.5	1,831,722	0	0.00000	1.00000	100.00
6.5	1,754,823	0	0.00000	1.00000	100.00
7.5	1,754,823	0	0.00000	1.00000	100.00
8.5	686,747	0	0.00000	1.00000	100.00
9.5	686,747	0	0.00000	1.00000	100.00
10.5	686,747	0	0.00000	1.00000	100.00
11.5	648,739	0	0.00000	1.00000	100.00
12.5	648,739	0	0.00000	1.00000	100.00
13.5	648,739	0	0.00000	1.00000	100.00
14.5	567,823	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 34008 - Supervisory System, Turbine

Placement Band - 1995 - 1998   Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 34008 - Supervisory System, Turbine

Placement Band - 1995 - 1998   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

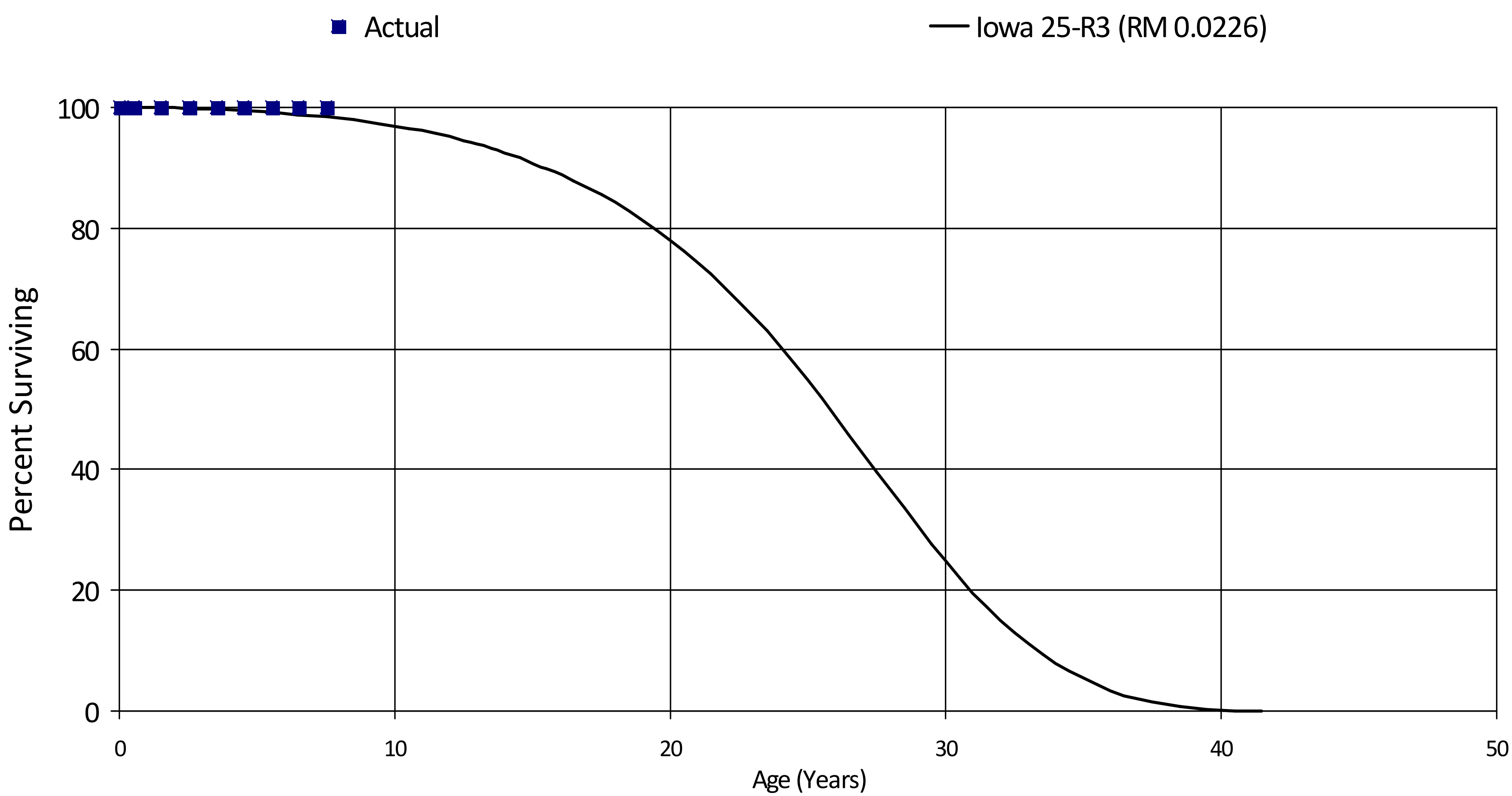
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	199,297	0	0.00000	1.00000	100.00
0.5	199,297	0	0.00000	1.00000	100.00
1.5	199,297	0	0.00000	1.00000	100.00
2.5	199,297	0	0.00000	1.00000	100.00
3.5	199,297	0	0.00000	1.00000	100.00
4.5	199,297	0	0.00000	1.00000	100.00
5.5	199,297	0	0.00000	1.00000	100.00
6.5	199,297	0	0.00000	1.00000	100.00
7.5	199,297	0	0.00000	1.00000	100.00
8.5	199,297	0	0.00000	1.00000	100.00
9.5	199,297	0	0.00000	1.00000	100.00
10.5	199,297	0	0.00000	1.00000	100.00
11.5	199,297	0	0.00000	1.00000	100.00
12.5	199,297	0	0.00000	1.00000	100.00
13.5	199,297	0	0.00000	1.00000	100.00
14.5	199,297	0	0.00000	1.00000	100.00
15.5	199,297	0	0.00000	1.00000	100.00
16.5	199,297	0	0.00000	1.00000	100.00
17.5	199,297	0	0.00000	1.00000	100.00
18.5	199,297	0	0.00000	1.00000	100.00
19.5	199,297	0	0.00000	1.00000	100.00
20.5	199,297	0	0.00000	1.00000	100.00
21.5	199,297	193,482	0.97082	0.02918	100.00
	Totals:	193,482			

BC Hydro Power Authority

Account 34013 - Generator Oil Coolers

Placement Band - 2006 - 2019   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 34013 - Generator Oil Coolers

Placement Band - 2006 - 2019   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

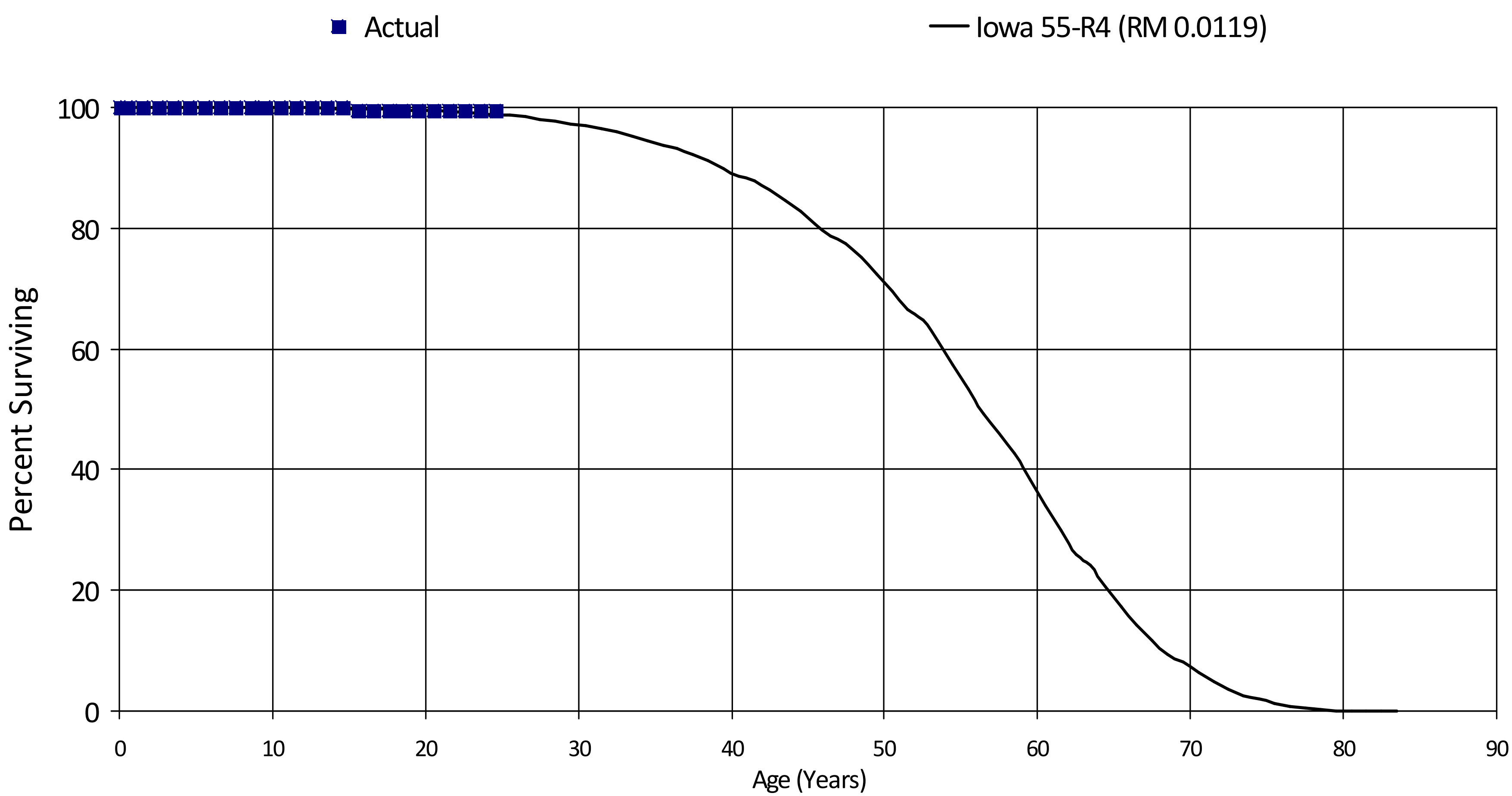
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,753,755	0	0.00000	1.00000	100.00
0.5	1,753,755	0	0.00000	1.00000	100.00
1.5	317,296	0	0.00000	1.00000	100.00
2.5	317,296	0	0.00000	1.00000	100.00
3.5	317,296	0	0.00000	1.00000	100.00
4.5	317,296	0	0.00000	1.00000	100.00
5.5	317,296	0	0.00000	1.00000	100.00
6.5	317,296	0	0.00000	1.00000	100.00
7.5	317,296	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 41001 - Runner / Water Wheel

Placement Band - 1963 - 2018   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 41001 - Runner / Water Wheel

Placement Band - 1963 - 2018   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

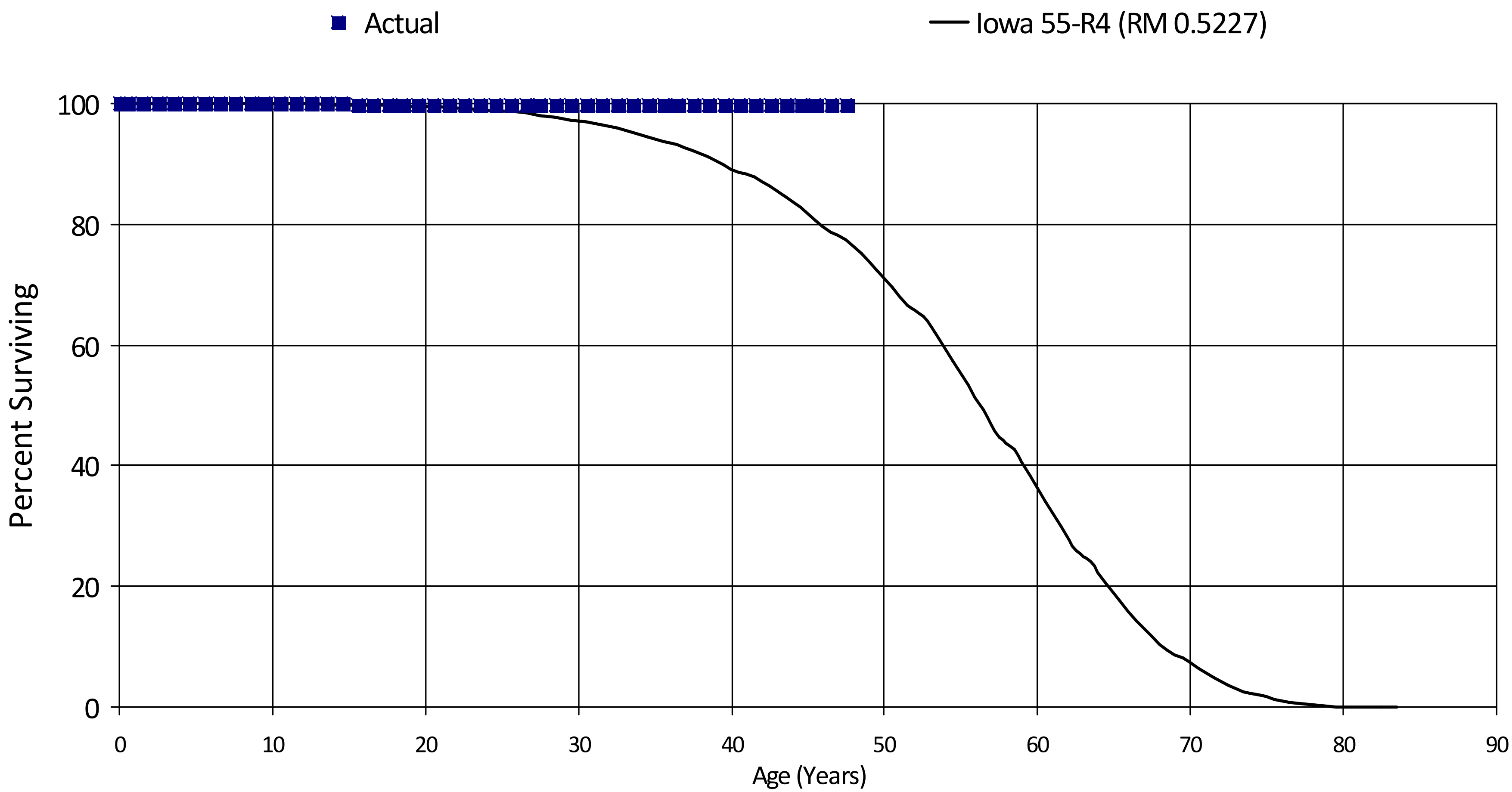
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	138,662,343	0	0.00000	1.00000	100.00
0.5	138,662,343	0	0.00000	1.00000	100.00
1.5	138,662,343	0	0.00000	1.00000	100.00
2.5	127,367,897	0	0.00000	1.00000	100.00
3.5	124,657,262	0	0.00000	1.00000	100.00
4.5	116,894,748	0	0.00000	1.00000	100.00
5.5	73,481,941	0	0.00000	1.00000	100.00
6.5	64,618,970	0	0.00000	1.00000	100.00
7.5	47,203,315	0	0.00000	1.00000	100.00
8.5	47,203,315	0	0.00000	1.00000	100.00
9.5	40,095,073	0	0.00000	1.00000	100.00
10.5	40,095,073	0	0.00000	1.00000	100.00
11.5	39,492,504	0	0.00000	1.00000	100.00
12.5	38,856,379	0	0.00000	1.00000	100.00
13.5	38,856,379	0	0.00000	1.00000	100.00
14.5	38,856,379	176,009	0.00453	0.99547	100.00
15.5	28,281,320	0	0.00000	1.00000	99.55
16.5	22,362,365	0	0.00000	1.00000	99.55
17.5	18,539,161	0	0.00000	1.00000	99.55
18.5	16,273,366	0	0.00000	1.00000	99.55
19.5	16,110,848	0	0.00000	1.00000	99.55
20.5	12,639,309	0	0.00000	1.00000	99.55
21.5	9,591,801	0	0.00000	1.00000	99.55
22.5	9,591,801	0	0.00000	1.00000	99.55
23.5	6,687,950	0	0.00000	1.00000	99.55
24.5	6,679,168	0	0.00000	1.00000	99.55
	Totals:	176,009			

BC Hydro Power Authority

Account 41002 - Governor System, Turbine

Placement Band - 1939 - 2020 Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 41002 - Governor System, Turbine

Placement Band - 1939 - 2020   Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	63,914,990	0	0.00000	1.00000	100.00
0.5	60,380,750	0	0.00000	1.00000	100.00
1.5	40,333,270	0	0.00000	1.00000	100.00
2.5	35,251,975	0	0.00000	1.00000	100.00
3.5	33,749,068	0	0.00000	1.00000	100.00
4.5	32,983,382	0	0.00000	1.00000	100.00
5.5	25,669,202	14,445	0.00056	0.99944	100.00
6.5	24,714,810	0	0.00000	1.00000	99.94
7.5	23,902,967	0	0.00000	1.00000	99.94
8.5	23,902,967	0	0.00000	1.00000	99.94
9.5	23,902,967	0	0.00000	1.00000	99.94
10.5	19,482,490	0	0.00000	1.00000	99.94
11.5	18,168,119	0	0.00000	1.00000	99.94
12.5	17,866,419	0	0.00000	1.00000	99.94
13.5	17,758,702	0	0.00000	1.00000	99.94
14.5	13,868,684	15,296	0.00110	0.99890	99.94
15.5	12,631,255	0	0.00000	1.00000	99.83
16.5	9,091,020	0	0.00000	1.00000	99.83
17.5	8,381,731	0	0.00000	1.00000	99.83
18.5	8,381,731	0	0.00000	1.00000	99.83
19.5	8,381,731	0	0.00000	1.00000	99.83
20.5	4,853,869	0	0.00000	1.00000	99.83
21.5	3,941,822	0	0.00000	1.00000	99.83
22.5	2,612,623	0	0.00000	1.00000	99.83
23.5	2,538,951	0	0.00000	1.00000	99.83
24.5	2,533,412	0	0.00000	1.00000	99.83
25.5	2,533,412	0	0.00000	1.00000	99.83
26.5	2,415,713	0	0.00000	1.00000	99.83

BC Hydro Power Authority

Account 41002 - Governor System, Turbine

Placement Band - 1939 - 2020 Experience Band - 2014 - 2020

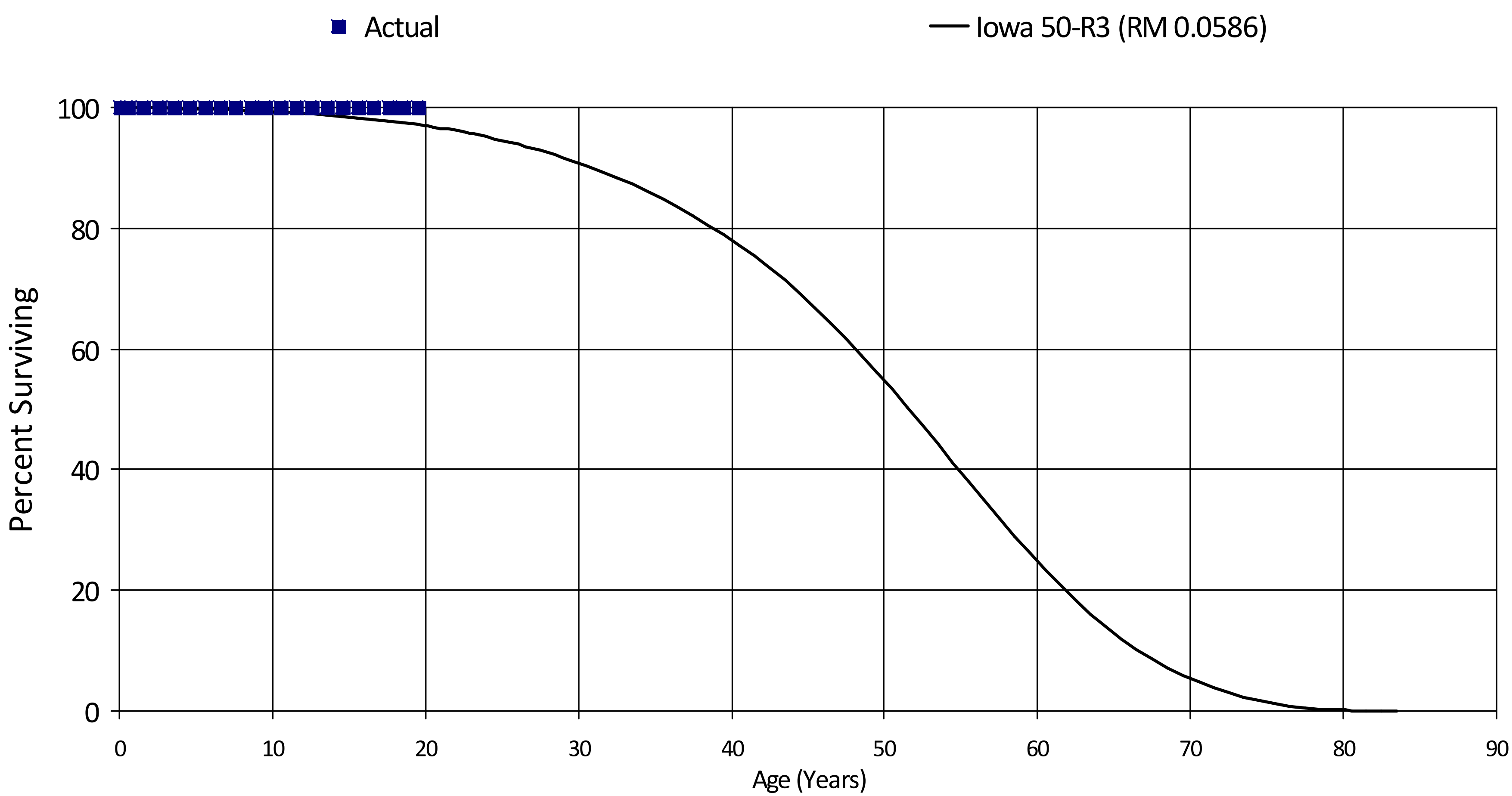
27.5	2,404,748	0	0.00000	1.00000	99.83
28.5	2,404,748	0	0.00000	1.00000	99.83
29.5	2,404,748	0	0.00000	1.00000	99.83
30.5	2,287,169	0	0.00000	1.00000	99.83
31.5	2,287,169	0	0.00000	1.00000	99.83
32.5	2,287,169	0	0.00000	1.00000	99.83
33.5	2,287,169	0	0.00000	1.00000	99.83
34.5	2,287,169	0	0.00000	1.00000	99.83
35.5	1,550,319	0	0.00000	1.00000	99.83
36.5	1,550,319	0	0.00000	1.00000	99.83
37.5	1,550,319	0	0.00000	1.00000	99.83
38.5	1,538,512	0	0.00000	1.00000	99.83
39.5	827,980	0	0.00000	1.00000	99.83
40.5	827,980	0	0.00000	1.00000	99.83
41.5	827,980	0	0.00000	1.00000	99.83
42.5	827,980	0	0.00000	1.00000	99.83
43.5	803,475	0	0.00000	1.00000	99.83
44.5	803,475	0	0.00000	1.00000	99.83
45.5	803,475	0	0.00000	1.00000	99.83
46.5	803,475	0	0.00000	1.00000	99.83
47.5	803,475	0	0.00000	1.00000	99.83
	Totals:	29,741			

BC Hydro Power Authority

Account 41003 - Casing, Embedded / Spiral Case

Placement Band - 1999 - 2019 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 41003 - Casing, Embedded / Spiral Case

Placement Band - 1999 - 2019   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

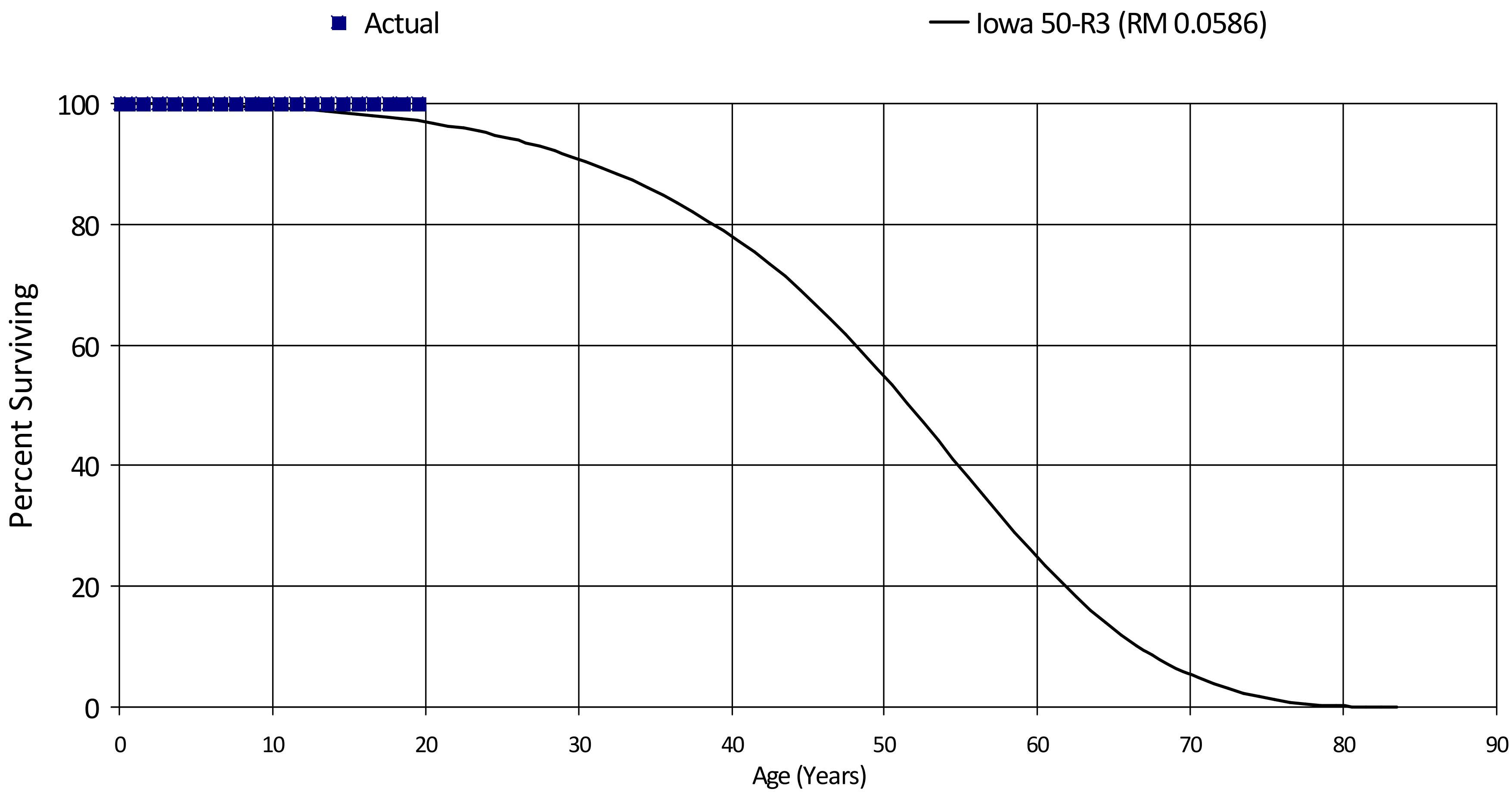
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	106,696,725	0	0.00000	1.00000	100.00
0.5	106,696,725	0	0.00000	1.00000	100.00
1.5	66,317,286	0	0.00000	1.00000	100.00
2.5	63,923,287	0	0.00000	1.00000	100.00
3.5	61,729,537	0	0.00000	1.00000	100.00
4.5	60,240,244	0	0.00000	1.00000	100.00
5.5	27,255,756	0	0.00000	1.00000	100.00
6.5	22,203,540	0	0.00000	1.00000	100.00
7.5	13,170,919	0	0.00000	1.00000	100.00
8.5	13,170,919	0	0.00000	1.00000	100.00
9.5	12,510,745	0	0.00000	1.00000	100.00
10.5	12,510,745	0	0.00000	1.00000	100.00
11.5	10,928,628	0	0.00000	1.00000	100.00
12.5	10,117,684	0	0.00000	1.00000	100.00
13.5	10,117,684	0	0.00000	1.00000	100.00
14.5	10,117,684	0	0.00000	1.00000	100.00
15.5	9,682,404	0	0.00000	1.00000	100.00
16.5	4,169,712	0	0.00000	1.00000	100.00
17.5	4,169,712	0	0.00000	1.00000	100.00
18.5	4,169,712	0	0.00000	1.00000	100.00
19.5	4,169,712	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 41004 - Shaft, Turbine

Placement Band - 1952 - 2018 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 41004 - Shaft, Turbine

Placement Band - 1952 - 2018 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

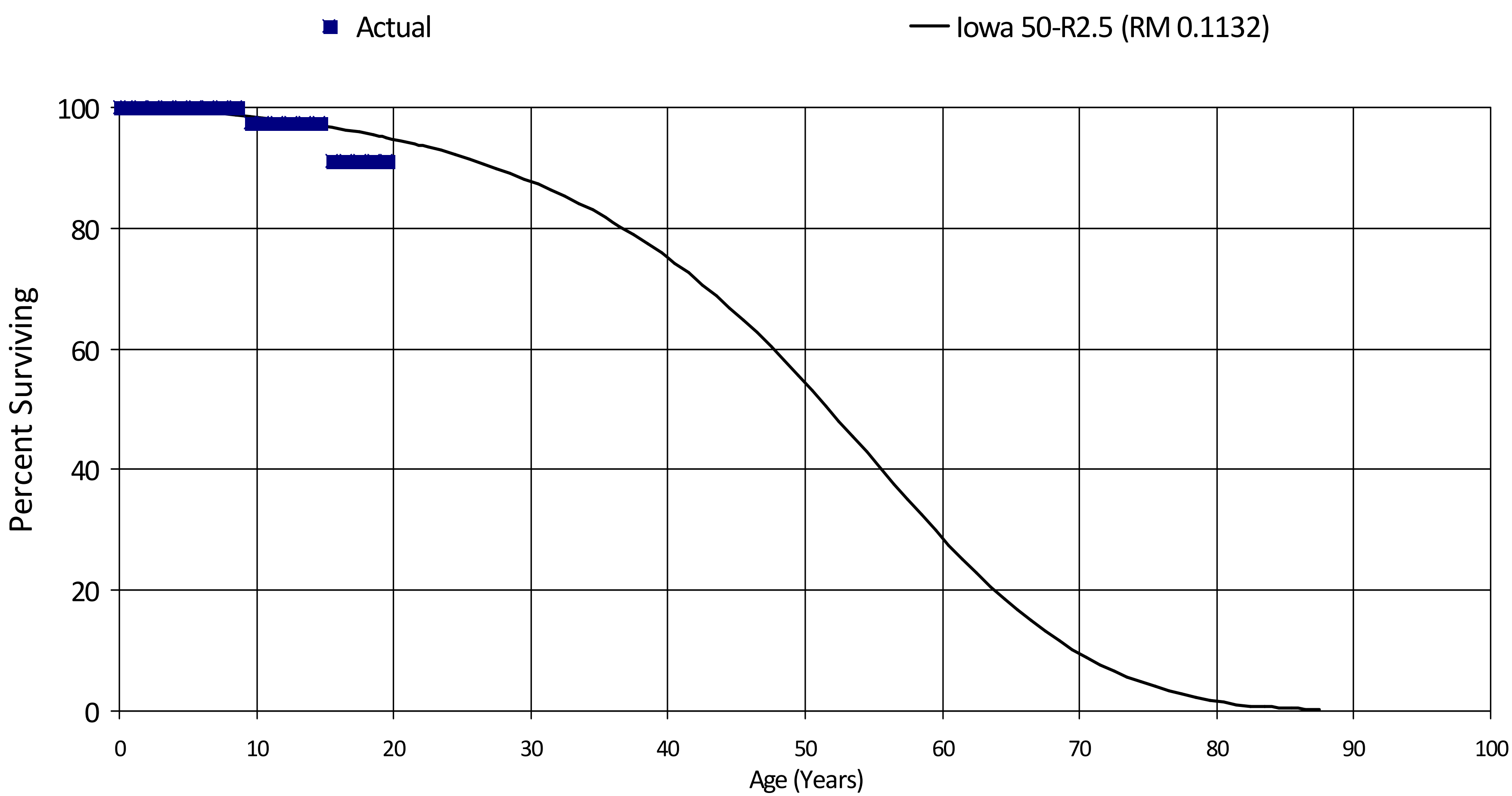
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	26,617,231	0	0.00000	1.00000	100.00
0.5	26,617,231	0	0.00000	1.00000	100.00
1.5	26,617,231	0	0.00000	1.00000	100.00
2.5	24,853,424	0	0.00000	1.00000	100.00
3.5	22,127,913	0	0.00000	1.00000	100.00
4.5	19,745,583	0	0.00000	1.00000	100.00
5.5	8,972,556	0	0.00000	1.00000	100.00
6.5	7,330,175	0	0.00000	1.00000	100.00
7.5	4,224,045	0	0.00000	1.00000	100.00
8.5	4,224,045	0	0.00000	1.00000	100.00
9.5	3,976,479	0	0.00000	1.00000	100.00
10.5	3,976,479	0	0.00000	1.00000	100.00
11.5	3,976,479	0	0.00000	1.00000	100.00
12.5	3,976,479	0	0.00000	1.00000	100.00
13.5	3,976,479	0	0.00000	1.00000	100.00
14.5	3,976,479	0	0.00000	1.00000	100.00
15.5	3,813,249	0	0.00000	1.00000	100.00
16.5	1,488,165	0	0.00000	1.00000	100.00
17.5	1,488,165	0	0.00000	1.00000	100.00
18.5	1,488,165	0	0.00000	1.00000	100.00
19.5	1,488,165	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 41005 - Gates, Wicket

Placement Band - 2000 - 2019 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 41005 - Gates, Wicket

Placement Band - 2000 - 2019   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

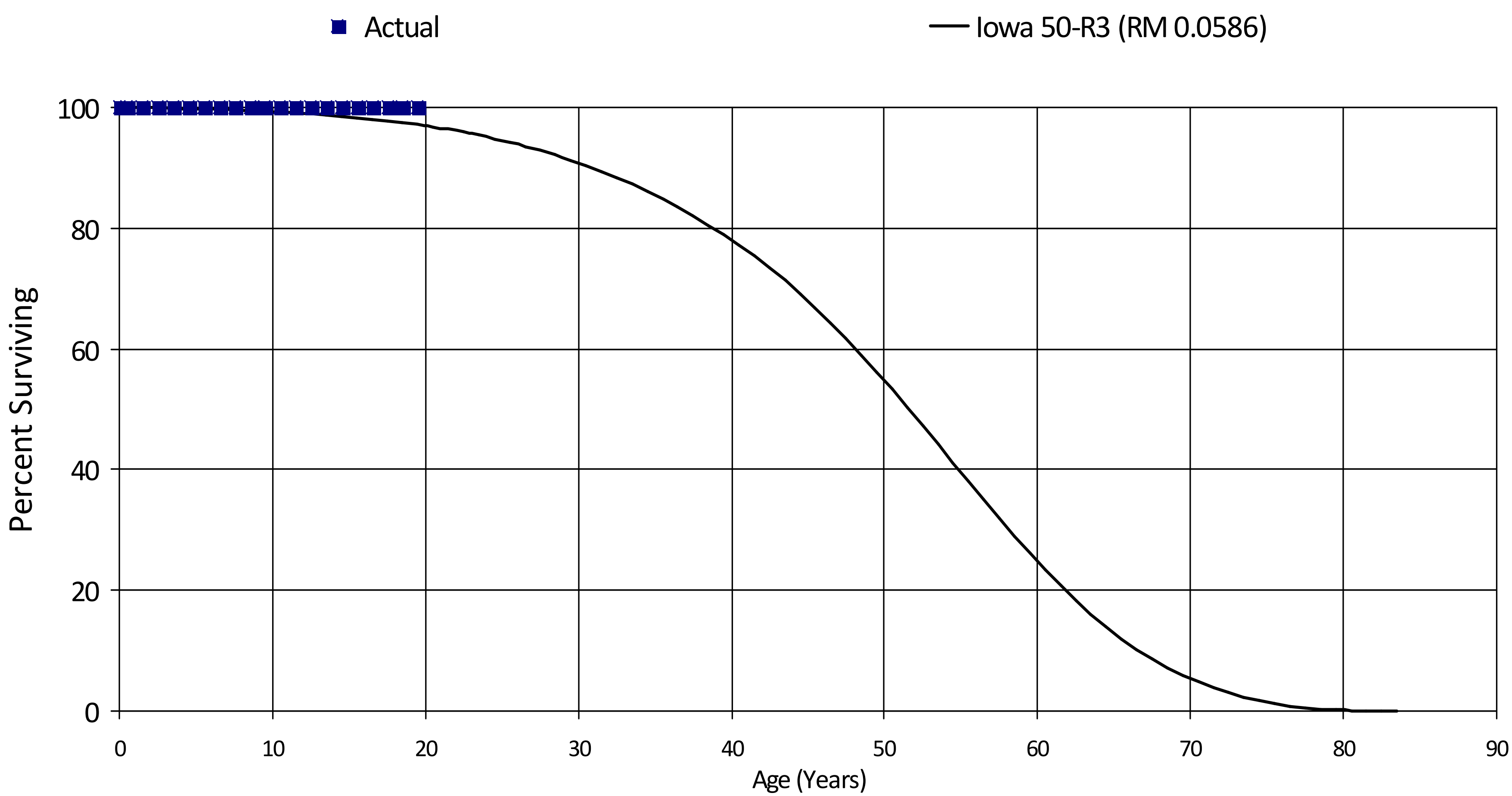
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	47,917,907	0	0.00000	1.00000	100.00
0.5	47,917,907	0	0.00000	1.00000	100.00
1.5	42,079,809	0	0.00000	1.00000	100.00
2.5	39,990,012	0	0.00000	1.00000	100.00
3.5	37,560,146	0	0.00000	1.00000	100.00
4.5	34,428,081	0	0.00000	1.00000	100.00
5.5	21,396,242	0	0.00000	1.00000	100.00
6.5	20,189,331	0	0.00000	1.00000	100.00
7.5	18,069,820	0	0.00000	1.00000	100.00
8.5	18,069,820	437,663	0.02422	0.97578	100.00
9.5	12,582,897	0	0.00000	1.00000	97.58
10.5	12,582,897	0	0.00000	1.00000	97.58
11.5	12,203,942	0	0.00000	1.00000	97.58
12.5	12,010,436	0	0.00000	1.00000	97.58
13.5	12,010,436	0	0.00000	1.00000	97.58
14.5	11,887,146	803,070	0.06756	0.93244	97.58
15.5	5,606,744	0	0.00000	1.00000	90.99
16.5	1,869,116	0	0.00000	1.00000	90.99
17.5	1,770,870	0	0.00000	1.00000	90.99
18.5	1,770,870	0	0.00000	1.00000	90.99
19.5	1,770,870	0	0.00000	1.00000	90.99
	Totals:	1,240,733			

BC Hydro Power Authority

Account 41006 - Cover, Head

Placement Band - 1999 - 2019   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 41006 - Cover, Head

Placement Band - 1999 - 2019   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

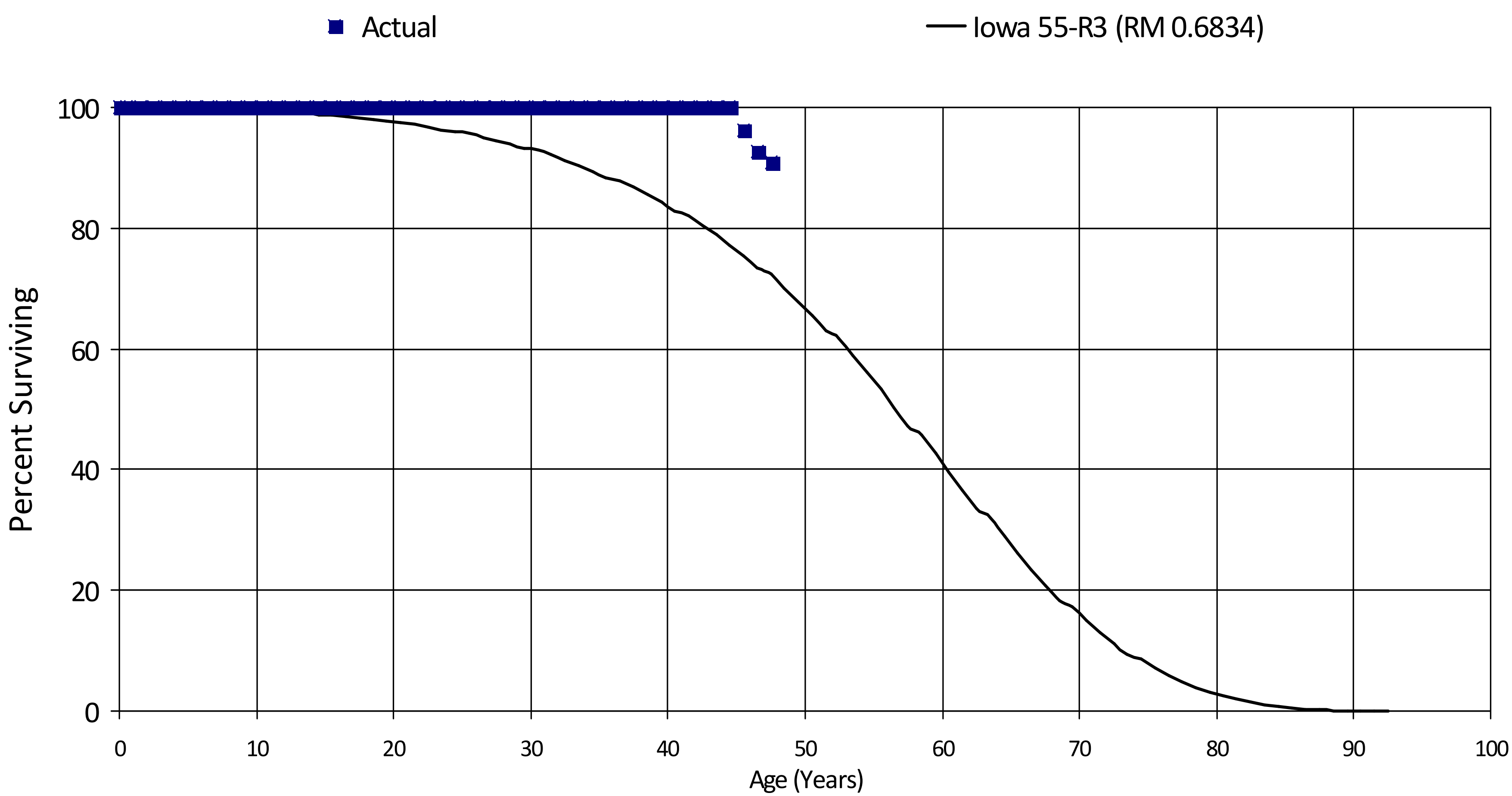
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	33,124,090	0	0.00000	1.00000	100.00
0.5	33,124,090	0	0.00000	1.00000	100.00
1.5	30,864,045	0	0.00000	1.00000	100.00
2.5	30,234,406	0	0.00000	1.00000	100.00
3.5	29,614,918	0	0.00000	1.00000	100.00
4.5	27,114,378	0	0.00000	1.00000	100.00
5.5	14,882,128	0	0.00000	1.00000	100.00
6.5	12,724,664	0	0.00000	1.00000	100.00
7.5	8,860,694	0	0.00000	1.00000	100.00
8.5	8,860,694	0	0.00000	1.00000	100.00
9.5	5,934,972	0	0.00000	1.00000	100.00
10.5	5,934,972	0	0.00000	1.00000	100.00
11.5	5,364,561	0	0.00000	1.00000	100.00
12.5	4,988,315	0	0.00000	1.00000	100.00
13.5	4,988,315	0	0.00000	1.00000	100.00
14.5	4,988,315	0	0.00000	1.00000	100.00
15.5	4,553,035	0	0.00000	1.00000	100.00
16.5	1,496,677	0	0.00000	1.00000	100.00
17.5	1,496,677	0	0.00000	1.00000	100.00
18.5	1,496,677	0	0.00000	1.00000	100.00
19.5	1,496,677	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 41007 - Turbine, Hydro, Comp. Pool

Placement Band - 1927 - 2019   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 41007 - Turbine, Hydro, Comp. Pool

Placement Band - 1927 - 2019   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	415,930,725	0	0.00000	1.00000	100.00
0.5	415,930,725	0	0.00000	1.00000	100.00
1.5	405,478,376	0	0.00000	1.00000	100.00
2.5	405,002,341	0	0.00000	1.00000	100.00
3.5	404,337,122	0	0.00000	1.00000	100.00
4.5	404,086,081	0	0.00000	1.00000	100.00
5.5	290,687,496	0	0.00000	1.00000	100.00
6.5	278,581,405	0	0.00000	1.00000	100.00
7.5	255,671,653	0	0.00000	1.00000	100.00
8.5	255,491,505	0	0.00000	1.00000	100.00
9.5	252,569,749	0	0.00000	1.00000	100.00
10.5	89,997,475	0	0.00000	1.00000	100.00
11.5	88,948,890	0	0.00000	1.00000	100.00
12.5	88,418,139	0	0.00000	1.00000	100.00
13.5	88,418,139	0	0.00000	1.00000	100.00
14.5	88,394,112	0	0.00000	1.00000	100.00
15.5	87,967,016	5,233	0.00006	0.99994	100.00
16.5	78,897,286	0	0.00000	1.00000	99.99
17.5	78,663,308	10,735	0.00014	0.99986	99.99
18.5	78,633,032	0	0.00000	1.00000	99.98
19.5	78,633,032	0	0.00000	1.00000	99.98
20.5	78,633,032	0	0.00000	1.00000	99.98
21.5	78,587,875	0	0.00000	1.00000	99.98
22.5	78,587,875	0	0.00000	1.00000	99.98
23.5	78,587,875	0	0.00000	1.00000	99.98
24.5	78,587,875	0	0.00000	1.00000	99.98
25.5	78,587,875	0	0.00000	1.00000	99.98
26.5	78,461,697	0	0.00000	1.00000	99.98

BC Hydro Power Authority

Account 41007 - Turbine, Hydro, Comp. Pool

Placement Band - 1927 - 2019   Experience Band - 2013 - 2020

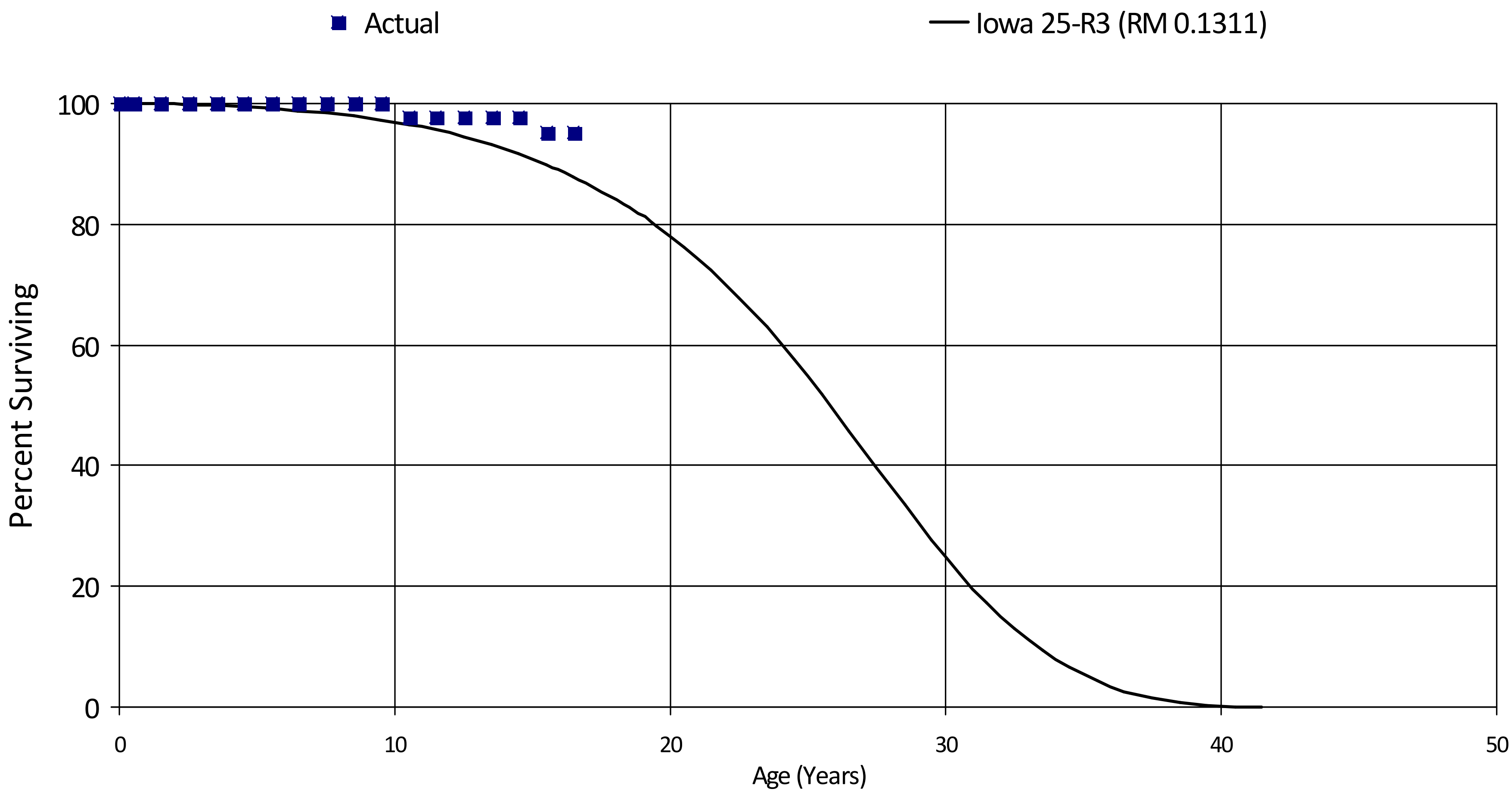
27.5	78,461,697	0	0.00000	1.00000	99.98
28.5	78,461,697	0	0.00000	1.00000	99.98
29.5	78,411,850	0	0.00000	1.00000	99.98
30.5	78,411,850	0	0.00000	1.00000	99.98
31.5	78,411,850	0	0.00000	1.00000	99.98
32.5	78,407,925	0	0.00000	1.00000	99.98
33.5	78,403,466	0	0.00000	1.00000	99.98
34.5	78,403,466	0	0.00000	1.00000	99.98
35.5	56,069,158	0	0.00000	1.00000	99.98
36.5	56,069,158	0	0.00000	1.00000	99.98
37.5	56,069,158	0	0.00000	1.00000	99.98
38.5	56,069,158	0	0.00000	1.00000	99.98
39.5	15,351,642	0	0.00000	1.00000	99.98
40.5	6,313,465	0	0.00000	1.00000	99.98
41.5	6,294,218	0	0.00000	1.00000	99.98
42.5	6,252,298	0	0.00000	1.00000	99.98
43.5	4,945,765	0	0.00000	1.00000	99.98
44.5	4,945,765	183,790	0.03716	0.96284	99.98
45.5	4,761,975	183,790	0.03860	0.96140	96.26
46.5	4,578,186	78,570	0.01716	0.98284	92.54
47.5	4,499,615	0	0.00000	1.00000	90.95
	Totals:	462,118			

BC Hydro Power Authority

Account 41008 - Bearings For Wicket Gate

Placement Band - 2003 - 2016   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 41008 - Bearings For Wicket Gate

Placement Band - 2003 - 2016   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

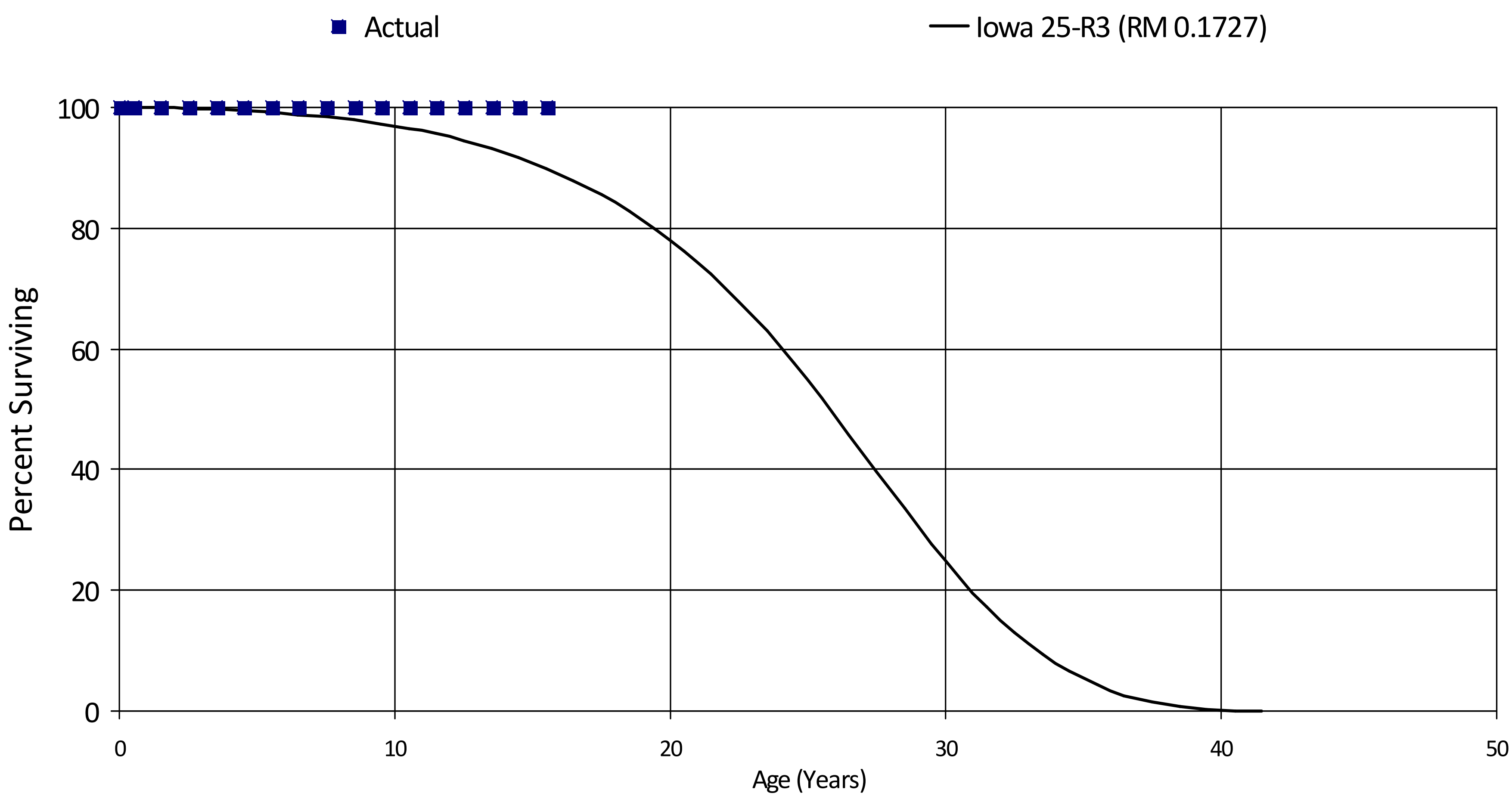
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	4,215,599	0	0.00000	1.00000	100.00
0.5	4,215,599	0	0.00000	1.00000	100.00
1.5	4,215,599	0	0.00000	1.00000	100.00
2.5	4,215,599	0	0.00000	1.00000	100.00
3.5	4,215,599	0	0.00000	1.00000	100.00
4.5	4,179,199	0	0.00000	1.00000	100.00
5.5	3,203,033	0	0.00000	1.00000	100.00
6.5	3,203,033	0	0.00000	1.00000	100.00
7.5	3,203,033	0	0.00000	1.00000	100.00
8.5	3,203,033	0	0.00000	1.00000	100.00
9.5	2,338,543	55,900	0.02390	0.97610	100.00
10.5	2,282,643	0	0.00000	1.00000	97.61
11.5	2,282,643	0	0.00000	1.00000	97.61
12.5	2,282,643	0	0.00000	1.00000	97.61
13.5	2,282,643	0	0.00000	1.00000	97.61
14.5	2,282,643	54,817	0.02401	0.97599	97.61
15.5	85,934	0	0.00000	1.00000	95.27
16.5	85,934	0	0.00000	1.00000	95.27
	Totals:	110,717			

BC Hydro Power Authority

Account 41501 - Draft Tube Water Depression System

Placement Band - 1970 - 2019 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 41501 - Draft Tube Water Depression System

Placement Band - 1970 - 2019 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

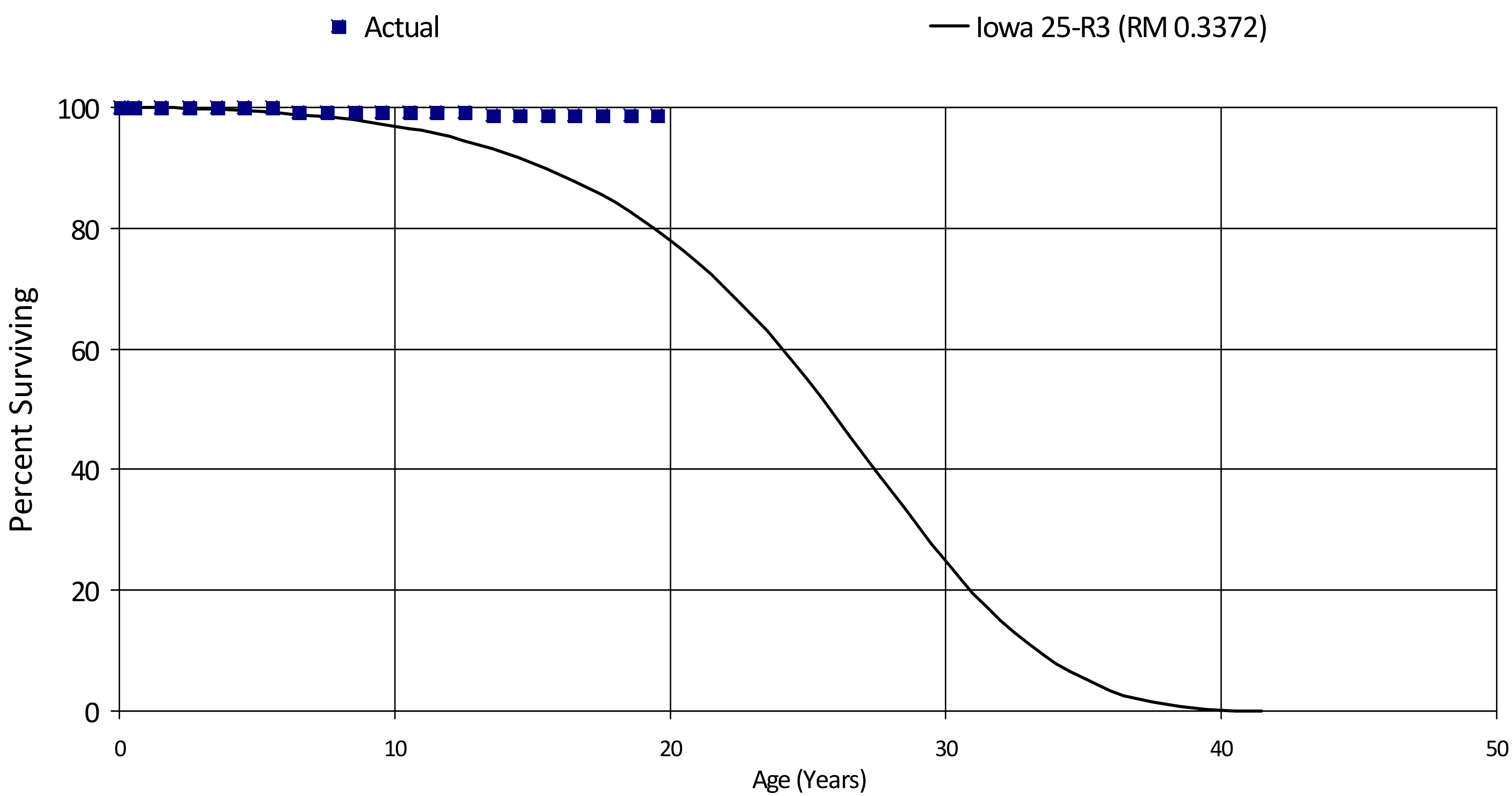
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	27,224,642	0	0.00000	1.00000	100.00
0.5	27,224,642	0	0.00000	1.00000	100.00
1.5	25,529,287	0	0.00000	1.00000	100.00
2.5	25,529,287	0	0.00000	1.00000	100.00
3.5	25,529,287	0	0.00000	1.00000	100.00
4.5	25,289,800	0	0.00000	1.00000	100.00
5.5	11,506,383	0	0.00000	1.00000	100.00
6.5	9,071,149	0	0.00000	1.00000	100.00
7.5	4,419,662	0	0.00000	1.00000	100.00
8.5	4,419,662	0	0.00000	1.00000	100.00
9.5	2,908,787	0	0.00000	1.00000	100.00
10.5	738,509	0	0.00000	1.00000	100.00
11.5	738,509	0	0.00000	1.00000	100.00
12.5	738,509	0	0.00000	1.00000	100.00
13.5	738,509	0	0.00000	1.00000	100.00
14.5	669,456	0	0.00000	1.00000	100.00
15.5	669,456	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 41601 - Unwatering System

Placement Band - 1964 - 2019 Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 41601 - Unwatering System

Placement Band - 1964 - 2019   Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

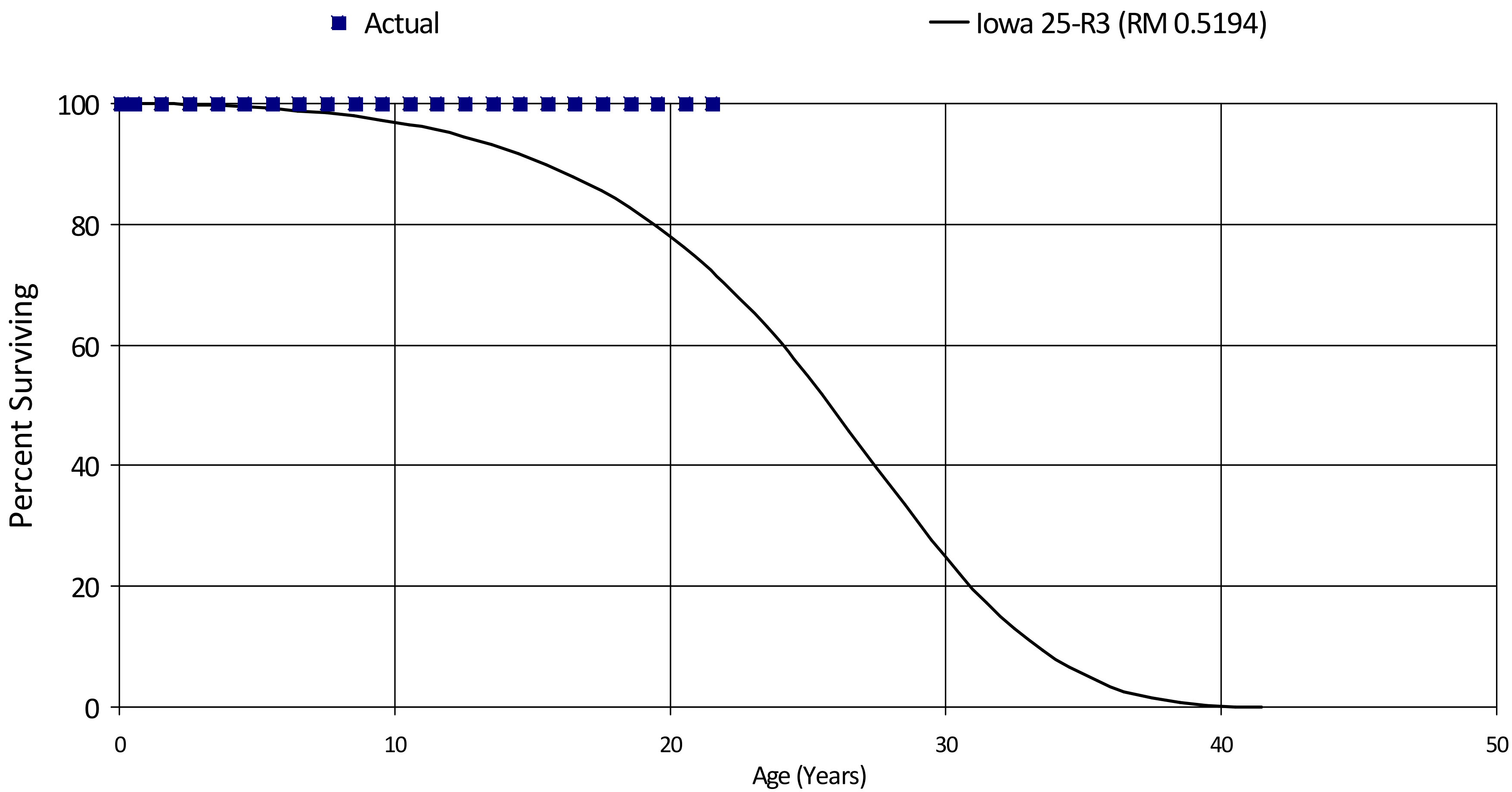
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	12,196,362	0	0.00000	1.00000	100.00
0.5	12,196,362	0	0.00000	1.00000	100.00
1.5	11,507,041	0	0.00000	1.00000	100.00
2.5	11,507,041	0	0.00000	1.00000	100.00
3.5	11,507,041	0	0.00000	1.00000	100.00
4.5	5,664,332	0	0.00000	1.00000	100.00
5.5	4,688,684	31,914	0.00681	0.99319	100.00
6.5	4,479,561	0	0.00000	1.00000	99.32
7.5	4,479,561	0	0.00000	1.00000	99.32
8.5	4,479,561	0	0.00000	1.00000	99.32
9.5	4,479,561	0	0.00000	1.00000	99.32
10.5	2,900,737	0	0.00000	1.00000	99.32
11.5	2,900,737	0	0.00000	1.00000	99.32
12.5	2,900,737	14,603	0.00503	0.99497	99.32
13.5	2,886,134	0	0.00000	1.00000	98.82
14.5	1,686,113	0	0.00000	1.00000	98.82
15.5	731,217	0	0.00000	1.00000	98.82
16.5	619,313	0	0.00000	1.00000	98.82
17.5	619,313	0	0.00000	1.00000	98.82
18.5	619,313	0	0.00000	1.00000	98.82
19.5	619,313	0	0.00000	1.00000	98.82
	Totals:	46,517			

BC Hydro Power Authority

Account 41701 - Turbine Air Injection Blower

Placement Band - 1998 - 2017   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 41701 - Turbine Air Injection Blower

Placement Band - 1998 - 2017   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

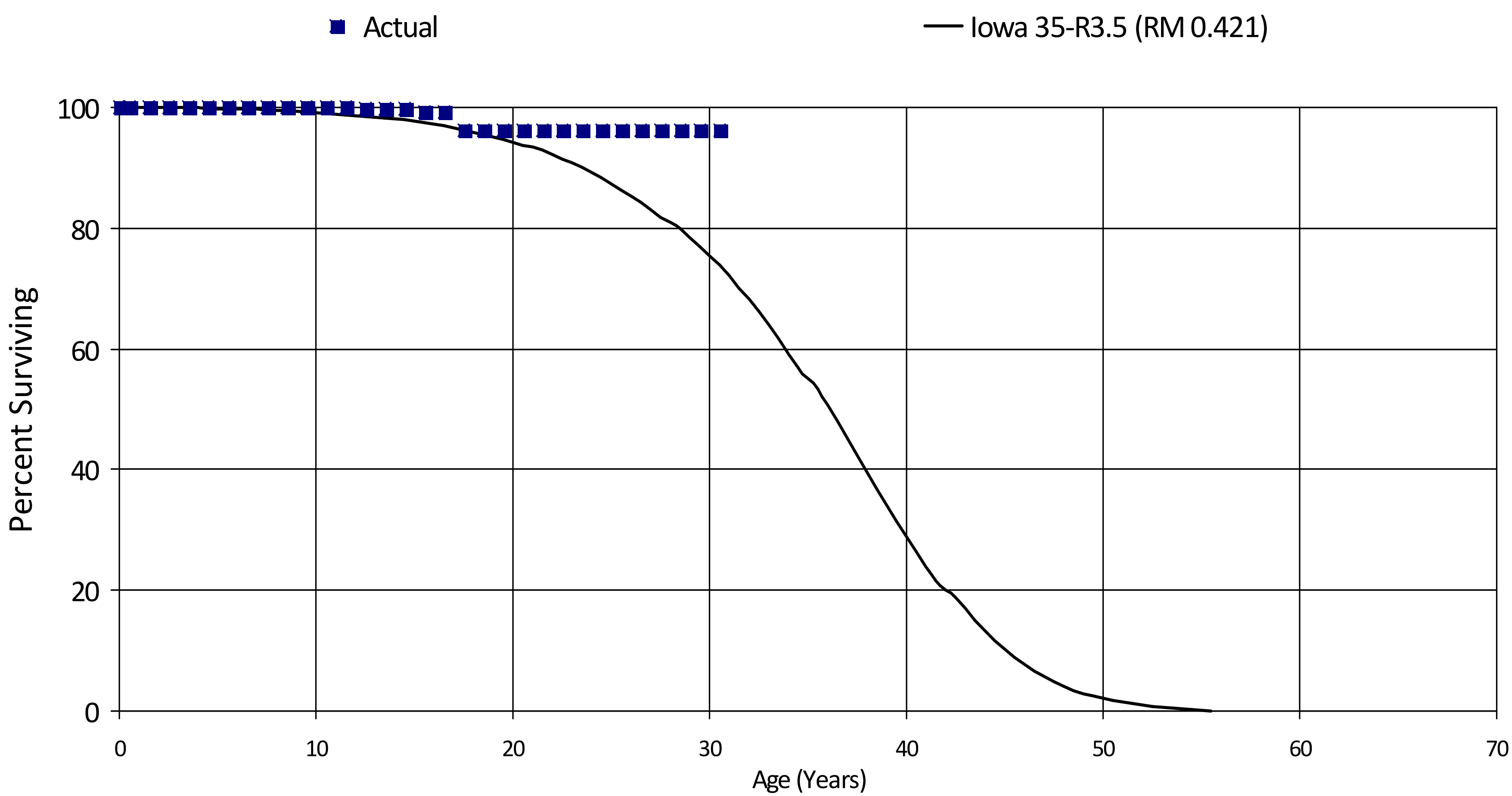
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	483,152	0	0.00000	1.00000	100.00
0.5	483,152	0	0.00000	1.00000	100.00
1.5	483,152	0	0.00000	1.00000	100.00
2.5	483,152	0	0.00000	1.00000	100.00
3.5	300,862	0	0.00000	1.00000	100.00
4.5	300,862	0	0.00000	1.00000	100.00
5.5	161,429	0	0.00000	1.00000	100.00
6.5	161,429	0	0.00000	1.00000	100.00
7.5	161,429	0	0.00000	1.00000	100.00
8.5	161,429	0	0.00000	1.00000	100.00
9.5	161,429	0	0.00000	1.00000	100.00
10.5	161,429	0	0.00000	1.00000	100.00
11.5	161,429	0	0.00000	1.00000	100.00
12.5	161,429	0	0.00000	1.00000	100.00
13.5	161,429	0	0.00000	1.00000	100.00
14.5	161,429	0	0.00000	1.00000	100.00
15.5	161,429	0	0.00000	1.00000	100.00
16.5	161,429	0	0.00000	1.00000	100.00
17.5	161,429	0	0.00000	1.00000	100.00
18.5	161,429	0	0.00000	1.00000	100.00
19.5	161,429	0	0.00000	1.00000	100.00
20.5	161,429	0	0.00000	1.00000	100.00
21.5	161,429	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 42001 - Coils, Stator

Placement Band - 1952 - 2019 Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 42001 - Coils, Stator

Placement Band - 1952 - 2019   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	217,369,265	0	0.00000	1.00000	100.00
0.5	217,369,265	0	0.00000	1.00000	100.00
1.5	171,413,987	0	0.00000	1.00000	100.00
2.5	152,913,200	0	0.00000	1.00000	100.00
3.5	144,986,763	0	0.00000	1.00000	100.00
4.5	134,284,014	0	0.00000	1.00000	100.00
5.5	103,511,688	0	0.00000	1.00000	100.00
6.5	103,511,688	0	0.00000	1.00000	100.00
7.5	103,511,688	0	0.00000	1.00000	100.00
8.5	103,511,688	0	0.00000	1.00000	100.00
9.5	103,511,688	0	0.00000	1.00000	100.00
10.5	101,147,008	0	0.00000	1.00000	100.00
11.5	78,935,790	290,000	0.00367	0.99633	100.00
12.5	60,139,664	0	0.00000	1.00000	99.63
13.5	27,086,184	0	0.00000	1.00000	99.63
14.5	27,086,184	106,873	0.00395	0.99605	99.63
15.5	26,941,600	0	0.00000	1.00000	99.24
16.5	15,730,063	470,629	0.02992	0.97008	99.24
17.5	15,259,433	0	0.00000	1.00000	96.27
18.5	15,259,433	0	0.00000	1.00000	96.27
19.5	15,259,433	0	0.00000	1.00000	96.27
20.5	11,898,706	0	0.00000	1.00000	96.27
21.5	10,553,981	0	0.00000	1.00000	96.27
22.5	9,065,939	0	0.00000	1.00000	96.27
23.5	8,619,950	0	0.00000	1.00000	96.27
24.5	8,612,454	0	0.00000	1.00000	96.27
25.5	8,612,454	0	0.00000	1.00000	96.27
26.5	8,612,454	0	0.00000	1.00000	96.27

BC Hydro Power Authority

Account 42001 - Coils, Stator

Placement Band - 1952 - 2019 Experience Band - 2012 - 2020

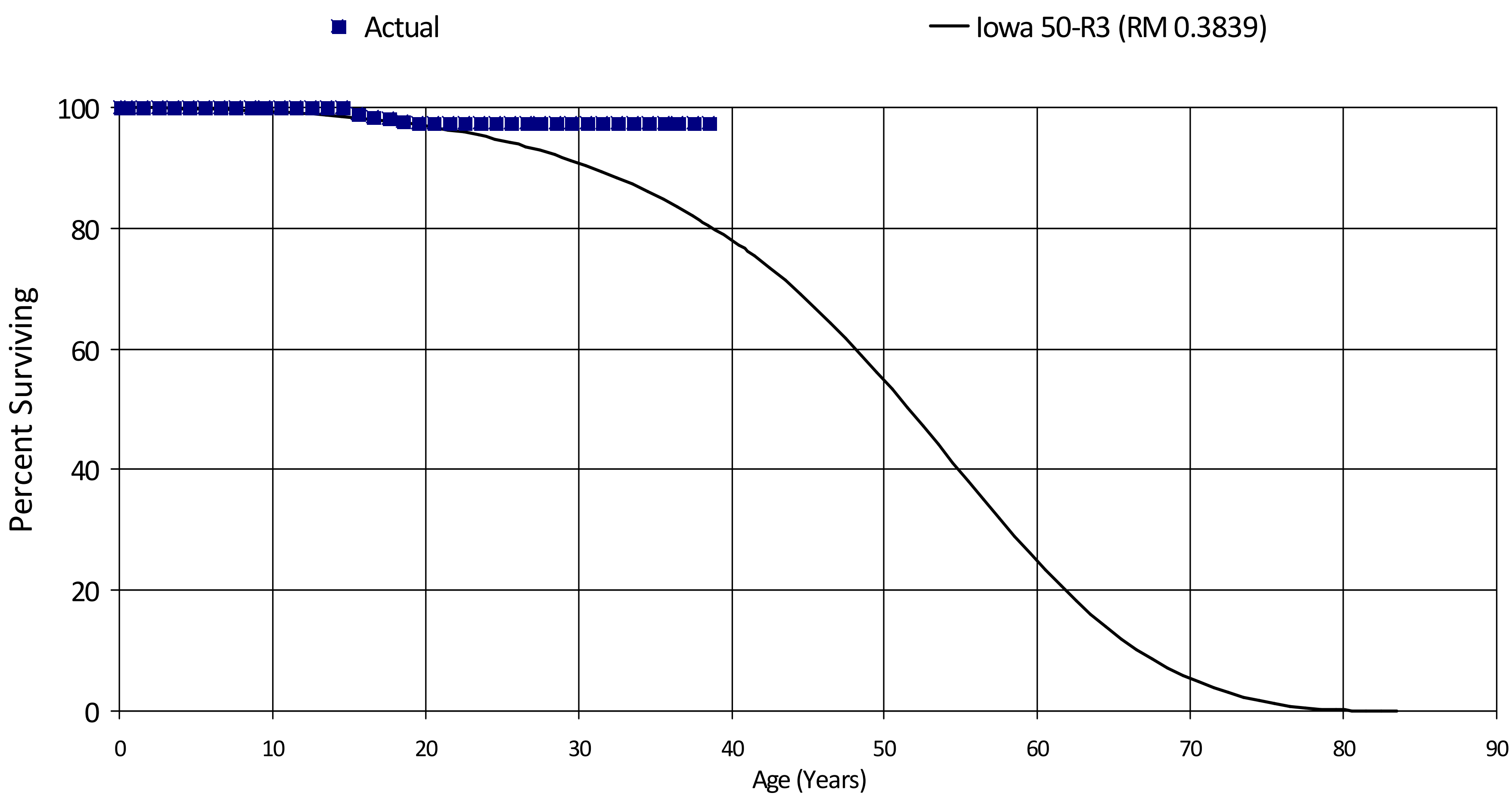
27.5	8,612,454	0	0.00000	1.00000	96.27
28.5	8,612,454	0	0.00000	1.00000	96.27
29.5	8,612,454	0	0.00000	1.00000	96.27
30.5	8,612,454	8,505,104	0.98754	0.01246	96.27
	Totals:	9,372,606			

BC Hydro Power Authority

Account 42002 - Rotor, Generator

Placement Band - 1981 - 2019 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 42002 - Rotor, Generator

Placement Band - 1981 - 2019   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	219,204,850	0	0.00000	1.00000	100.00
0.5	219,204,850	0	0.00000	1.00000	100.00
1.5	168,111,028	0	0.00000	1.00000	100.00
2.5	164,370,797	0	0.00000	1.00000	100.00
3.5	154,784,826	0	0.00000	1.00000	100.00
4.5	147,990,290	0	0.00000	1.00000	100.00
5.5	107,502,373	0	0.00000	1.00000	100.00
6.5	101,249,901	0	0.00000	1.00000	100.00
7.5	88,255,139	0	0.00000	1.00000	100.00
8.5	88,255,139	0	0.00000	1.00000	100.00
9.5	88,255,139	0	0.00000	1.00000	100.00
10.5	82,896,727	0	0.00000	1.00000	100.00
11.5	62,617,681	0	0.00000	1.00000	100.00
12.5	50,381,454	0	0.00000	1.00000	100.00
13.5	32,413,220	0	0.00000	1.00000	100.00
14.5	32,413,220	363,622	0.01122	0.98878	100.00
15.5	32,049,598	91,607	0.00286	0.99714	98.88
16.5	24,551,487	92,593	0.00377	0.99623	98.60
17.5	19,188,925	122,775	0.00640	0.99360	98.23
18.5	19,066,149	9,161	0.00048	0.99952	97.60
19.5	19,056,989	0	0.00000	1.00000	97.55
20.5	12,839,115	0	0.00000	1.00000	97.55
21.5	12,839,115	0	0.00000	1.00000	97.55
22.5	12,839,115	0	0.00000	1.00000	97.55
23.5	5,786,131	0	0.00000	1.00000	97.55
24.5	5,778,345	0	0.00000	1.00000	97.55
25.5	5,778,345	0	0.00000	1.00000	97.55
26.5	5,778,345	0	0.00000	1.00000	97.55

BC Hydro Power Authority

Account 42002 - Rotor, Generator

Placement Band - 1981 - 2019 Experience Band - 2013 - 2020

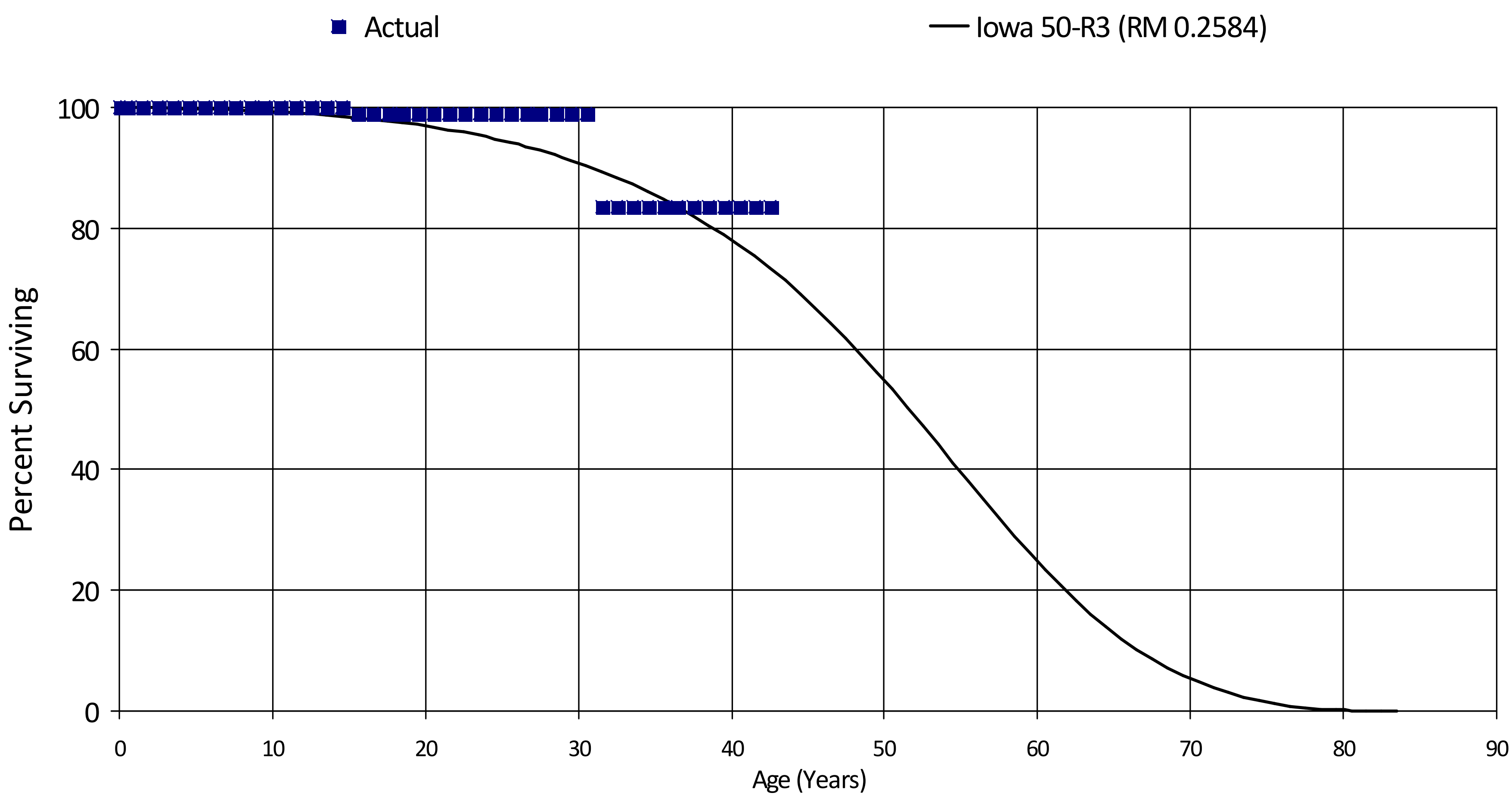
27.5	5,778,345	0	0.00000	1.00000	97.55
28.5	5,778,345	0	0.00000	1.00000	97.55
29.5	5,778,345	0	0.00000	1.00000	97.55
30.5	5,778,345	0	0.00000	1.00000	97.55
31.5	5,778,345	0	0.00000	1.00000	97.55
32.5	5,778,345	0	0.00000	1.00000	97.55
33.5	5,778,345	0	0.00000	1.00000	97.55
34.5	5,778,345	0	0.00000	1.00000	97.55
35.5	5,778,345	0	0.00000	1.00000	97.55
36.5	5,778,345	0	0.00000	1.00000	97.55
37.5	5,778,345	0	0.00000	1.00000	97.55
38.5	5,778,345	0	0.00000	1.00000	97.55
	Totals:	679,758			

BC Hydro Power Authority

Account 42003 - Generator, Composite Pool

Placement Band - 1927 - 2019   Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 42003 - Generator, Composite Pool

Placement Band - 1927 - 2019 Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	385,114,909	0	0.00000	1.00000	100.00
0.5	385,114,909	0	0.00000	1.00000	100.00
1.5	317,483,520	0	0.00000	1.00000	100.00
2.5	315,775,058	0	0.00000	1.00000	100.00
3.5	315,603,362	0	0.00000	1.00000	100.00
4.5	314,495,912	0	0.00000	1.00000	100.00
5.5	238,196,361	0	0.00000	1.00000	100.00
6.5	238,196,361	0	0.00000	1.00000	100.00
7.5	238,196,361	0	0.00000	1.00000	100.00
8.5	237,612,743	0	0.00000	1.00000	100.00
9.5	235,760,285	0	0.00000	1.00000	100.00
10.5	105,422,054	0	0.00000	1.00000	100.00
11.5	87,916,566	0	0.00000	1.00000	100.00
12.5	74,314,872	23,952	0.00032	0.99968	100.00
13.5	47,648,101	0	0.00000	1.00000	99.97
14.5	47,596,540	414,230	0.00870	0.99130	99.97
15.5	46,231,231	42,639	0.00092	0.99908	99.10
16.5	46,163,881	0	0.00000	1.00000	99.01
17.5	46,163,881	17,035	0.00037	0.99963	99.01
18.5	46,110,542	0	0.00000	1.00000	98.97
19.5	46,110,542	0	0.00000	1.00000	98.97
20.5	46,085,785	0	0.00000	1.00000	98.97
21.5	46,085,785	0	0.00000	1.00000	98.97
22.5	46,085,785	0	0.00000	1.00000	98.97
23.5	46,085,785	0	0.00000	1.00000	98.97
24.5	46,085,785	0	0.00000	1.00000	98.97
25.5	46,085,785	0	0.00000	1.00000	98.97
26.5	45,927,269	0	0.00000	1.00000	98.97

BC Hydro Power Authority

Account 42003 - Generator, Composite Pool

Placement Band - 1927 - 2019 Experience Band - 2012 - 2020

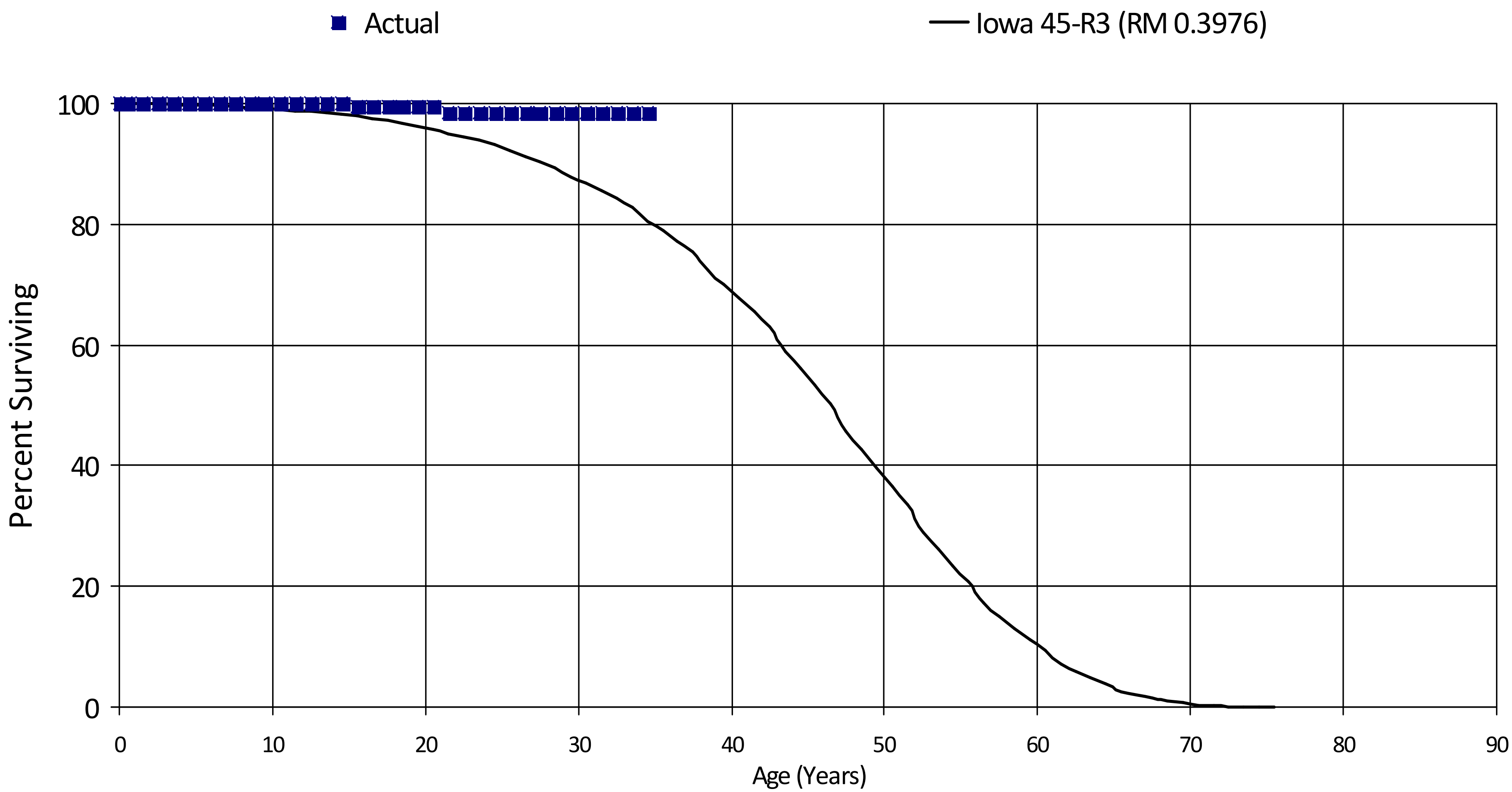
27.5	45,923,112	0	0.00000	1.00000	98.97
28.5	45,287,264	0	0.00000	1.00000	98.97
29.5	45,276,066	0	0.00000	1.00000	98.97
30.5	45,276,066	7,087,586	0.15654	0.84346	98.97
31.5	38,188,480	0	0.00000	1.00000	83.48
32.5	38,188,480	0	0.00000	1.00000	83.48
33.5	38,147,048	0	0.00000	1.00000	83.48
34.5	38,008,075	0	0.00000	1.00000	83.48
35.5	11,621,870	0	0.00000	1.00000	83.48
36.5	11,621,870	0	0.00000	1.00000	83.48
37.5	11,621,870	0	0.00000	1.00000	83.48
38.5	11,621,870	0	0.00000	1.00000	83.48
39.5	11,621,870	0	0.00000	1.00000	83.48
40.5	5,051,207	0	0.00000	1.00000	83.48
41.5	5,048,363	0	0.00000	1.00000	83.48
42.5	5,048,363	0	0.00000	1.00000	83.48
	Totals:	7,585,442			

BC Hydro Power Authority

Account 42101 - Exciter, Rotary

Placement Band - 1954 - 2011 Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 42101 - Exciter, Rotary

Placement Band - 1954 - 2011   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	4,664,679	0	0.00000	1.00000	100.00
0.5	4,664,679	0	0.00000	1.00000	100.00
1.5	4,664,679	0	0.00000	1.00000	100.00
2.5	4,664,679	0	0.00000	1.00000	100.00
3.5	4,664,679	0	0.00000	1.00000	100.00
4.5	4,664,679	0	0.00000	1.00000	100.00
5.5	4,664,679	0	0.00000	1.00000	100.00
6.5	4,664,679	0	0.00000	1.00000	100.00
7.5	4,664,679	0	0.00000	1.00000	100.00
8.5	4,664,679	0	0.00000	1.00000	100.00
9.5	4,593,710	0	0.00000	1.00000	100.00
10.5	2,425,804	0	0.00000	1.00000	100.00
11.5	2,425,804	0	0.00000	1.00000	100.00
12.5	2,425,804	0	0.00000	1.00000	100.00
13.5	2,425,804	0	0.00000	1.00000	100.00
14.5	2,425,804	14,329	0.00591	0.99409	100.00
15.5	2,250,716	0	0.00000	1.00000	99.41
16.5	2,250,716	0	0.00000	1.00000	99.41
17.5	2,051,657	0	0.00000	1.00000	99.41
18.5	2,051,657	0	0.00000	1.00000	99.41
19.5	2,051,657	0	0.00000	1.00000	99.41
20.5	2,051,657	18,070	0.00881	0.99119	99.41
21.5	2,033,587	0	0.00000	1.00000	98.53
22.5	2,033,587	0	0.00000	1.00000	98.53
23.5	2,033,587	0	0.00000	1.00000	98.53
24.5	2,033,587	0	0.00000	1.00000	98.53
25.5	2,033,587	0	0.00000	1.00000	98.53
26.5	2,017,440	0	0.00000	1.00000	98.53

BC Hydro Power Authority

Account 42101 - Exciter, Rotary

Placement Band - 1954 - 2011 Experience Band - 2017 - 2020

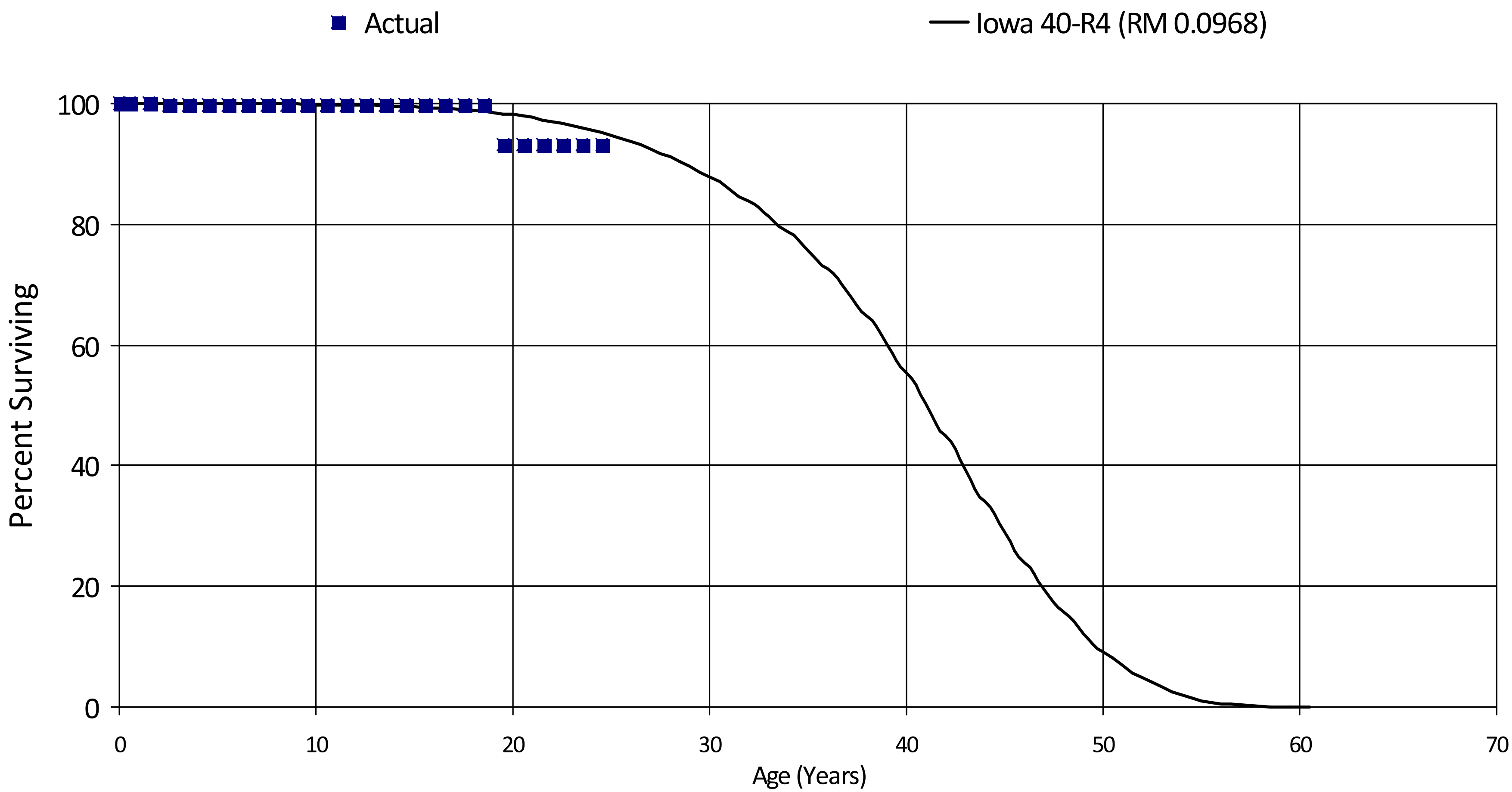
27.5	2,017,440	0	0.00000	1.00000	98.53
28.5	2,017,440	0	0.00000	1.00000	98.53
29.5	2,017,440	0	0.00000	1.00000	98.53
30.5	2,017,440	0	0.00000	1.00000	98.53
31.5	2,017,440	0	0.00000	1.00000	98.53
32.5	2,017,440	0	0.00000	1.00000	98.53
33.5	2,017,440	0	0.00000	1.00000	98.53
34.5	2,017,440	0	0.00000	1.00000	98.53
	Totals:	32,399			

BC Hydro Power Authority

Account 42102 - Exciter, Static

Placement Band - 1954 - 2020 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 42102 - Exciter, Static

Placement Band - 1954 - 2020   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

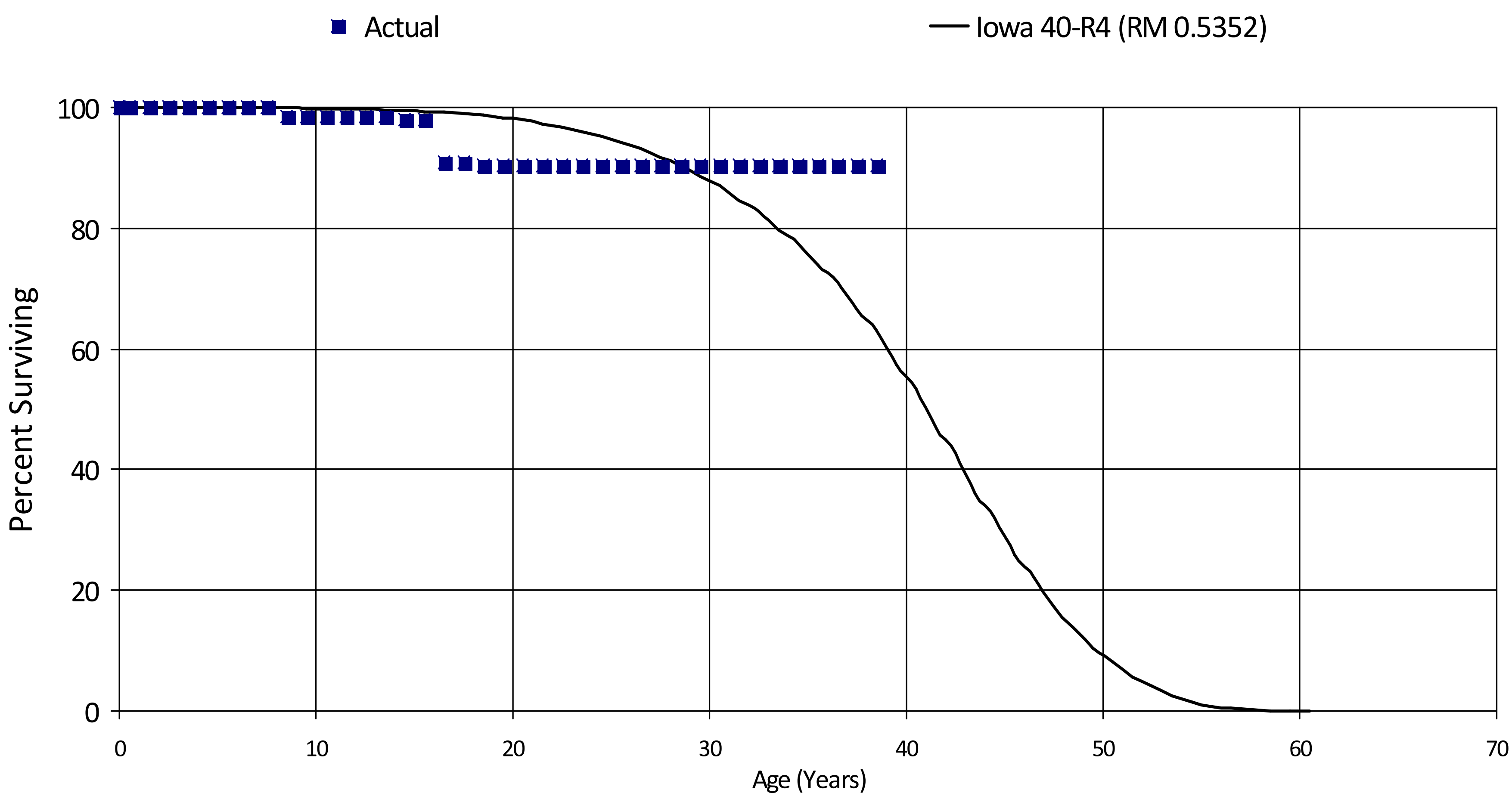
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	52,095,450	0	0.00000	1.00000	100.00
0.5	48,642,175	0	0.00000	1.00000	100.00
1.5	34,573,768	68,231	0.00197	0.99803	100.00
2.5	29,659,762	0	0.00000	1.00000	99.80
3.5	28,175,571	0	0.00000	1.00000	99.80
4.5	26,369,521	0	0.00000	1.00000	99.80
5.5	20,528,474	0	0.00000	1.00000	99.80
6.5	20,449,976	0	0.00000	1.00000	99.80
7.5	20,449,976	0	0.00000	1.00000	99.80
8.5	18,588,833	0	0.00000	1.00000	99.80
9.5	18,588,833	0	0.00000	1.00000	99.80
10.5	18,588,833	0	0.00000	1.00000	99.80
11.5	13,071,865	0	0.00000	1.00000	99.80
12.5	10,186,774	0	0.00000	1.00000	99.80
13.5	10,186,774	0	0.00000	1.00000	99.80
14.5	9,538,412	14,646	0.00154	0.99846	99.80
15.5	4,705,870	0	0.00000	1.00000	99.65
16.5	3,276,542	0	0.00000	1.00000	99.65
17.5	2,456,922	0	0.00000	1.00000	99.65
18.5	1,094,066	71,693	0.06553	0.93447	99.65
19.5	1,006,286	0	0.00000	1.00000	93.12
20.5	850,059	0	0.00000	1.00000	93.12
21.5	850,059	0	0.00000	1.00000	93.12
22.5	598,091	0	0.00000	1.00000	93.12
23.5	598,091	0	0.00000	1.00000	93.12
24.5	598,091	0	0.00000	1.00000	93.12
	Totals:	154,570			

BC Hydro Power Authority

Account 42104 - Exciter, Composite Pool

Placement Band - 1972 - 2019 Experience Band - 2019 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 42104 - Exciter, Composite Pool

Placement Band - 1972 - 2019   Experience Band - 2019 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	14,819,824	0	0.00000	1.00000	100.00
0.5	14,819,824	0	0.00000	1.00000	100.00
1.5	11,698,541	0	0.00000	1.00000	100.00
2.5	11,698,541	0	0.00000	1.00000	100.00
3.5	11,698,541	0	0.00000	1.00000	100.00
4.5	11,698,541	0	0.00000	1.00000	100.00
5.5	11,698,541	0	0.00000	1.00000	100.00
6.5	9,852,842	0	0.00000	1.00000	100.00
7.5	9,852,842	139,685	0.01418	0.98582	100.00
8.5	7,997,981	0	0.00000	1.00000	98.58
9.5	7,844,065	0	0.00000	1.00000	98.58
10.5	1,857,039	0	0.00000	1.00000	98.58
11.5	1,857,038	0	0.00000	1.00000	98.58
12.5	1,857,038	0	0.00000	1.00000	98.58
13.5	1,857,038	9,340	0.00503	0.99497	98.58
14.5	1,813,638	0	0.00000	1.00000	98.08
15.5	1,813,638	134,728	0.07429	0.92571	98.08
16.5	1,678,910	0	0.00000	1.00000	90.79
17.5	1,678,910	7,668	0.00457	0.99543	90.79
18.5	1,656,046	0	0.00000	1.00000	90.38
19.5	1,656,046	0	0.00000	1.00000	90.38
20.5	896,305	0	0.00000	1.00000	90.38
21.5	896,305	0	0.00000	1.00000	90.38
22.5	896,305	0	0.00000	1.00000	90.38
23.5	896,305	0	0.00000	1.00000	90.38
24.5	896,305	0	0.00000	1.00000	90.38
25.5	896,305	0	0.00000	1.00000	90.38
26.5	896,305	0	0.00000	1.00000	90.38

BC Hydro Power Authority

Account 42104 - Exciter, Composite Pool

Placement Band - 1972 - 2019 Experience Band - 2019 - 2020

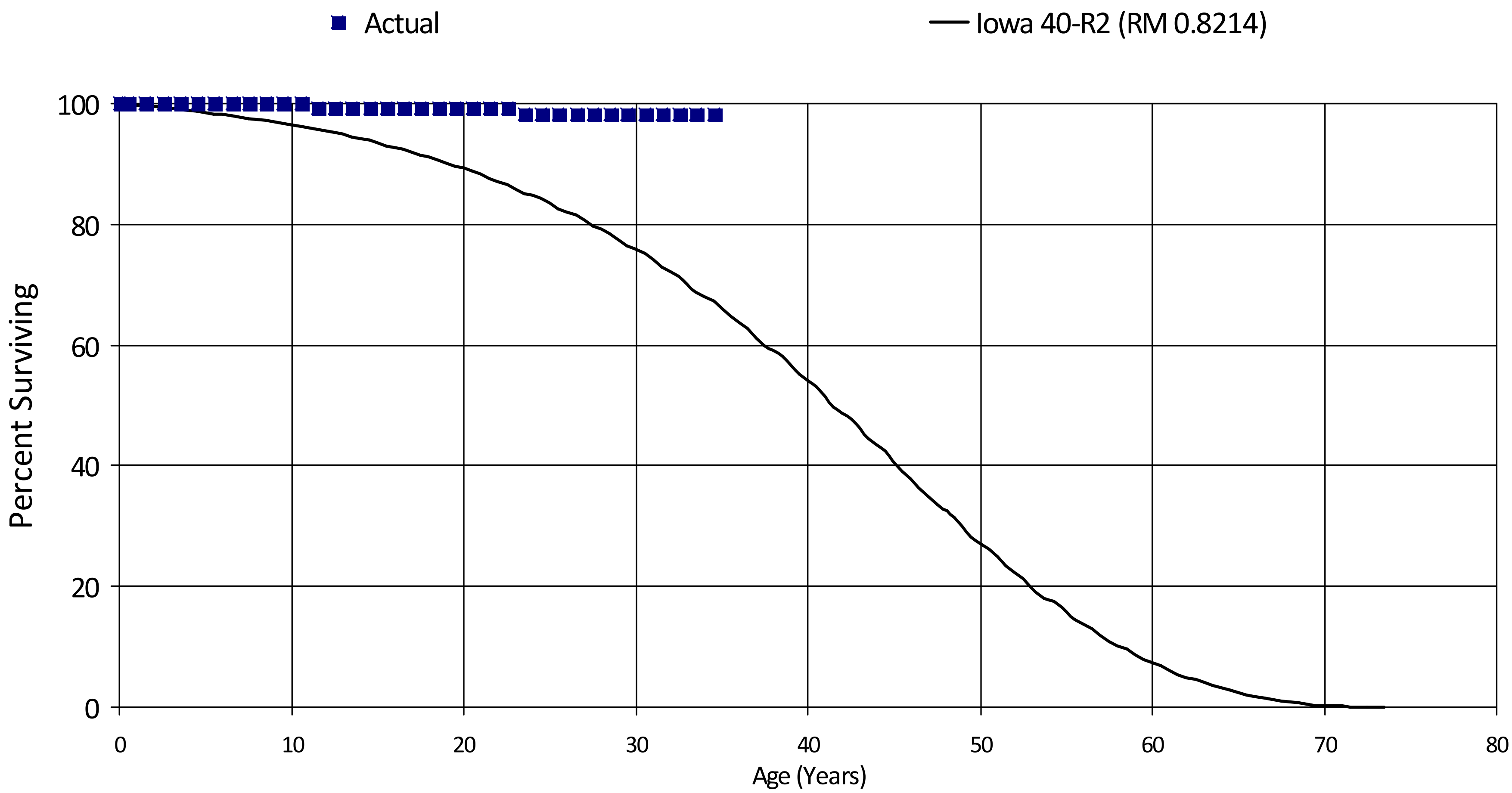
27.5	896,305	0	0.00000	1.00000	90.38
28.5	882,538	0	0.00000	1.00000	90.38
29.5	869,864	0	0.00000	1.00000	90.38
30.5	845,095	0	0.00000	1.00000	90.38
31.5	845,095	0	0.00000	1.00000	90.38
32.5	845,095	0	0.00000	1.00000	90.38
33.5	845,095	0	0.00000	1.00000	90.38
34.5	845,095	0	0.00000	1.00000	90.38
35.5	845,095	0	0.00000	1.00000	90.38
36.5	845,095	0	0.00000	1.00000	90.38
37.5	845,095	0	0.00000	1.00000	90.38
38.5	845,095	0	0.00000	1.00000	90.38
	Totals:	291,421			

BC Hydro Power Authority

Account 42501 - Piping, Water Cooling System

Placement Band - 1974 - 2019   Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 42501 - Piping, Water Cooling System

Placement Band - 1974 - 2019 Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	35,623,501	0	0.00000	1.00000	100.00
0.5	35,623,501	0	0.00000	1.00000	100.00
1.5	29,444,930	0	0.00000	1.00000	100.00
2.5	29,444,930	0	0.00000	1.00000	100.00
3.5	28,077,766	0	0.00000	1.00000	100.00
4.5	23,354,036	0	0.00000	1.00000	100.00
5.5	6,932,648	0	0.00000	1.00000	100.00
6.5	6,932,648	0	0.00000	1.00000	100.00
7.5	6,932,648	0	0.00000	1.00000	100.00
8.5	6,932,648	0	0.00000	1.00000	100.00
9.5	6,932,648	0	0.00000	1.00000	100.00
10.5	6,932,648	48,995	0.00707	0.99293	100.00
11.5	6,883,653	0	0.00000	1.00000	99.29
12.5	4,986,726	0	0.00000	1.00000	99.29
13.5	4,986,726	8	0.00000	1.00000	99.29
14.5	3,503,844	0	0.00000	1.00000	99.29
15.5	3,044,522	0	0.00000	1.00000	99.29
16.5	1,883,519	0	0.00000	1.00000	99.29
17.5	1,474,309	0	0.00000	1.00000	99.29
18.5	1,473,543	0	0.00000	1.00000	99.29
19.5	1,455,941	0	0.00000	1.00000	99.29
20.5	1,455,941	0	0.00000	1.00000	99.29
21.5	1,455,941	0	0.00000	1.00000	99.29
22.5	1,455,941	14,771	0.01015	0.98985	99.29
23.5	1,432,988	0	0.00000	1.00000	98.28
24.5	1,427,580	0	0.00000	1.00000	98.28
25.5	1,367,551	0	0.00000	1.00000	98.28
26.5	619,380	0	0.00000	1.00000	98.28

BC Hydro Power Authority

Account 42501 - Piping, Water Cooling System

Placement Band - 1974 - 2019   Experience Band - 2016 - 2020

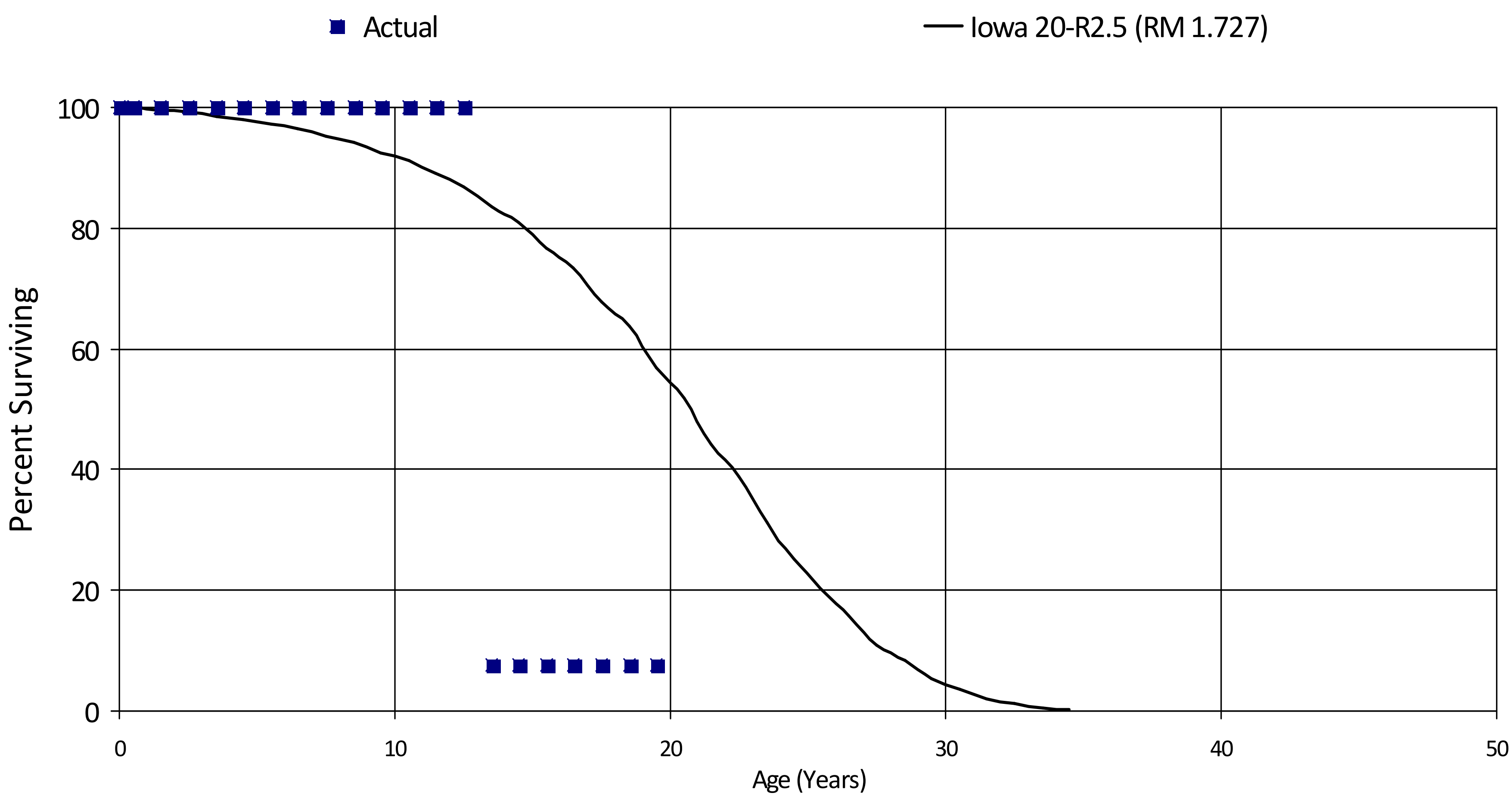
27.5	619,375	0	0.00000	1.00000	98.28
28.5	555,409	0	0.00000	1.00000	98.28
29.5	499,772	0	0.00000	1.00000	98.28
30.5	499,772	0	0.00000	1.00000	98.28
31.5	497,033	0	0.00000	1.00000	98.28
32.5	459,933	0	0.00000	1.00000	98.28
33.5	459,933	0	0.00000	1.00000	98.28
34.5	459,933	9,152	0.01990	0.98010	98.28
	Totals:	72,926			

BC Hydro Power Authority

Account 42502 - Monitoring System, Cooling

Placement Band - 1995 - 2017 Experience Band - 2015 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 42502 - Monitoring System, Cooling

Placement Band - 1995 - 2017   Experience Band - 2015 - 2020

RETIREMENT RATE ANALYSIS

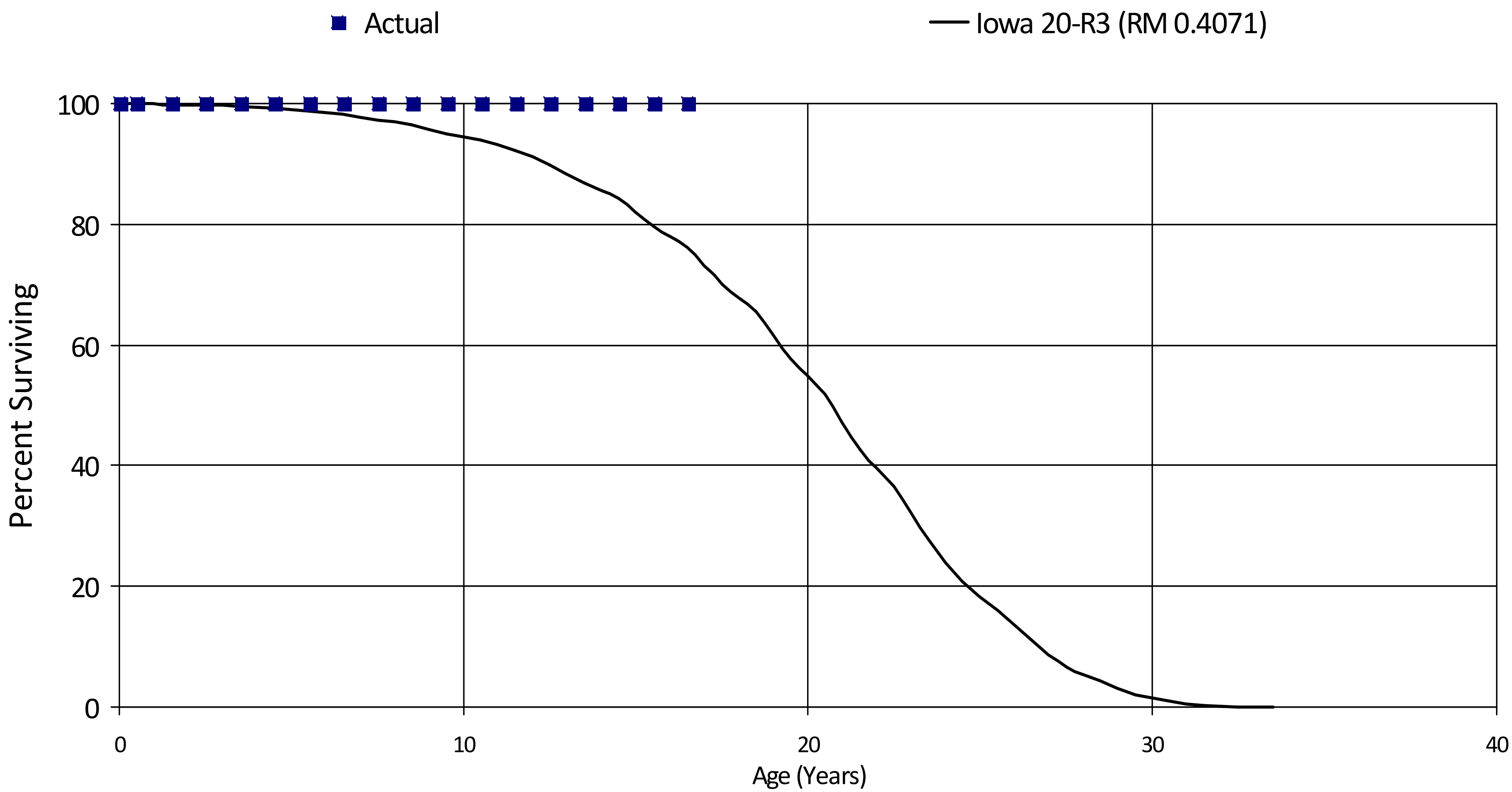
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	656,415	0	0.00000	1.00000	100.00
0.5	656,415	0	0.00000	1.00000	100.00
1.5	656,415	0	0.00000	1.00000	100.00
2.5	656,415	0	0.00000	1.00000	100.00
3.5	594,540	0	0.00000	1.00000	100.00
4.5	594,540	0	0.00000	1.00000	100.00
5.5	594,540	0	0.00000	1.00000	100.00
6.5	594,540	0	0.00000	1.00000	100.00
7.5	594,540	0	0.00000	1.00000	100.00
8.5	594,540	0	0.00000	1.00000	100.00
9.5	566,353	0	0.00000	1.00000	100.00
10.5	566,353	0	0.00000	1.00000	100.00
11.5	566,353	0	0.00000	1.00000	100.00
12.5	566,353	522,626	0.92279	0.07721	100.00
13.5	12,823	0	0.00000	1.00000	7.72
14.5	12,823	0	0.00000	1.00000	7.72
15.5	12,823	0	0.00000	1.00000	7.72
16.5	12,823	0	0.00000	1.00000	7.72
17.5	12,823	0	0.00000	1.00000	7.72
18.5	12,823	0	0.00000	1.00000	7.72
19.5	12,823	12,720	0.99193	0.00807	7.72
	Totals:	535,346			

BC Hydro Power Authority

Account 46501 - Cooling System, Water

Placement Band - 1977 - 2014 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 46501 - Cooling System, Water

Placement Band - 1977 - 2014   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

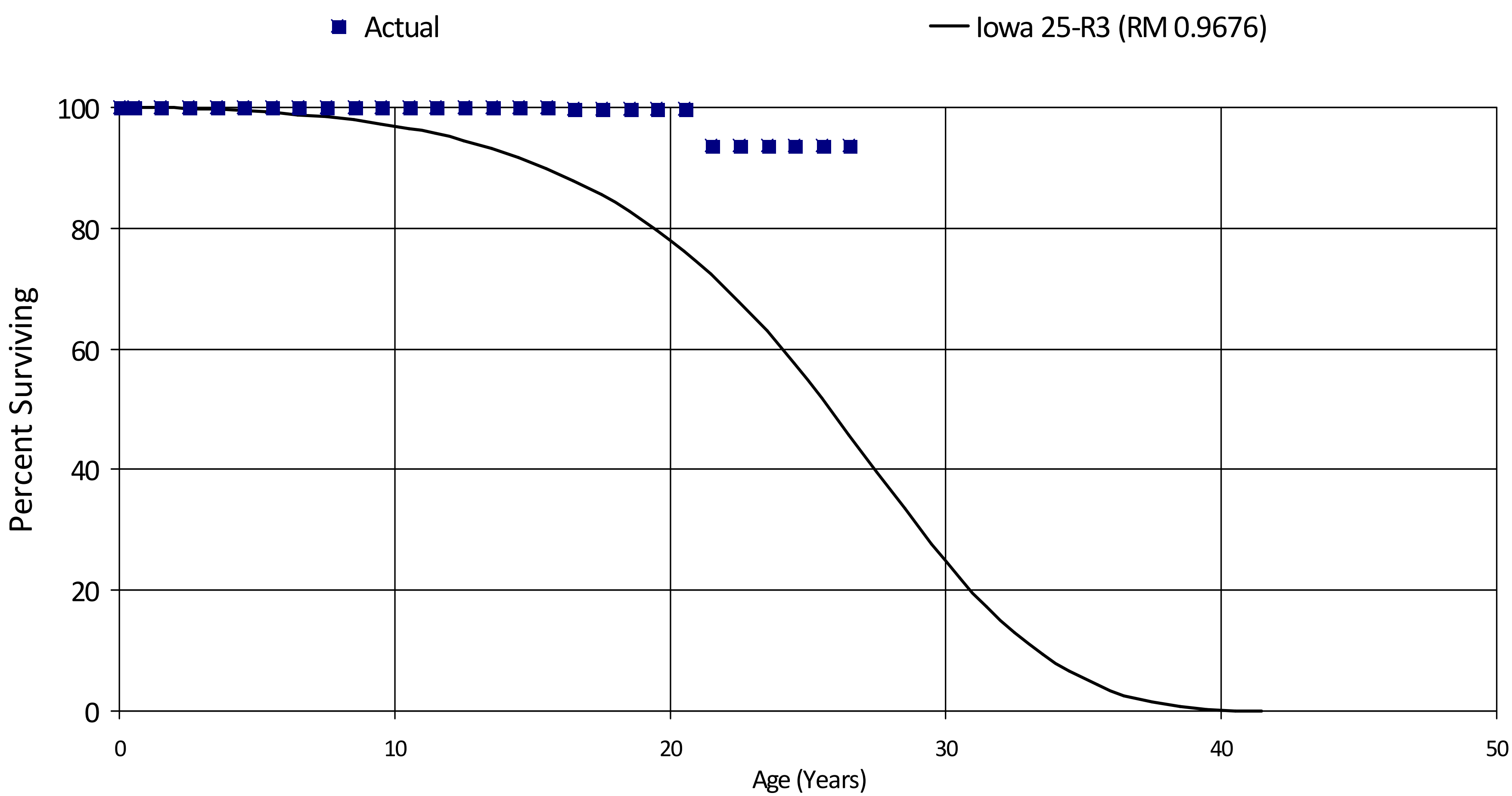
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,084,930	0	0.00000	1.00000	100.00
0.5	1,084,930	0	0.00000	1.00000	100.00
1.5	1,084,930	0	0.00000	1.00000	100.00
2.5	1,084,930	0	0.00000	1.00000	100.00
3.5	1,084,930	0	0.00000	1.00000	100.00
4.5	1,084,930	0	0.00000	1.00000	100.00
5.5	1,084,930	0	0.00000	1.00000	100.00
6.5	499,431	0	0.00000	1.00000	100.00
7.5	499,431	0	0.00000	1.00000	100.00
8.5	499,431	0	0.00000	1.00000	100.00
9.5	499,431	0	0.00000	1.00000	100.00
10.5	49,792	0	0.00000	1.00000	100.00
11.5	49,792	0	0.00000	1.00000	100.00
12.5	49,792	0	0.00000	1.00000	100.00
13.5	49,792	0	0.00000	1.00000	100.00
14.5	49,792	0	0.00000	1.00000	100.00
15.5	49,792	0	0.00000	1.00000	100.00
16.5	49,792	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 46502 - Engine, Internal Combustion

Placement Band - 1964 - 2018   Experience Band - 2015 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 46502 - Engine, Internal Combustion

Placement Band - 1964 - 2018   Experience Band - 2015 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	21,225,237	0	0.00000	1.00000	100.00
0.5	21,225,237	0	0.00000	1.00000	100.00
1.5	21,225,237	0	0.00000	1.00000	100.00
2.5	13,531,587	0	0.00000	1.00000	100.00
3.5	13,531,587	0	0.00000	1.00000	100.00
4.5	13,531,587	0	0.00000	1.00000	100.00
5.5	13,531,587	0	0.00000	1.00000	100.00
6.5	13,531,587	0	0.00000	1.00000	100.00
7.5	7,563,870	0	0.00000	1.00000	100.00
8.5	7,563,870	0	0.00000	1.00000	100.00
9.5	7,563,870	0	0.00000	1.00000	100.00
10.5	7,563,870	0	0.00000	1.00000	100.00
11.5	7,563,870	0	0.00000	1.00000	100.00
12.5	7,563,870	0	0.00000	1.00000	100.00
13.5	7,563,870	0	0.00000	1.00000	100.00
14.5	7,563,870	0	0.00000	1.00000	100.00
15.5	7,434,094	9,752	0.00131	0.99869	100.00
16.5	7,424,342	0	0.00000	1.00000	99.87
17.5	7,424,342	0	0.00000	1.00000	99.87
18.5	7,424,342	0	0.00000	1.00000	99.87
19.5	7,424,342	0	0.00000	1.00000	99.87
20.5	7,424,342	453,604	0.06110	0.93890	99.87
21.5	6,629,335	0	0.00000	1.00000	93.77
22.5	2,448,467	0	0.00000	1.00000	93.77
23.5	1,868,509	0	0.00000	1.00000	93.77
24.5	1,202,743	0	0.00000	1.00000	93.77
25.5	1,202,743	0	0.00000	1.00000	93.77
26.5	407,843	0	0.00000	1.00000	93.77

BC Hydro Power Authority

Account 46502 - Engine, Internal Combustion

Placement Band - 1964 - 2018   Experience Band - 2015 - 2020

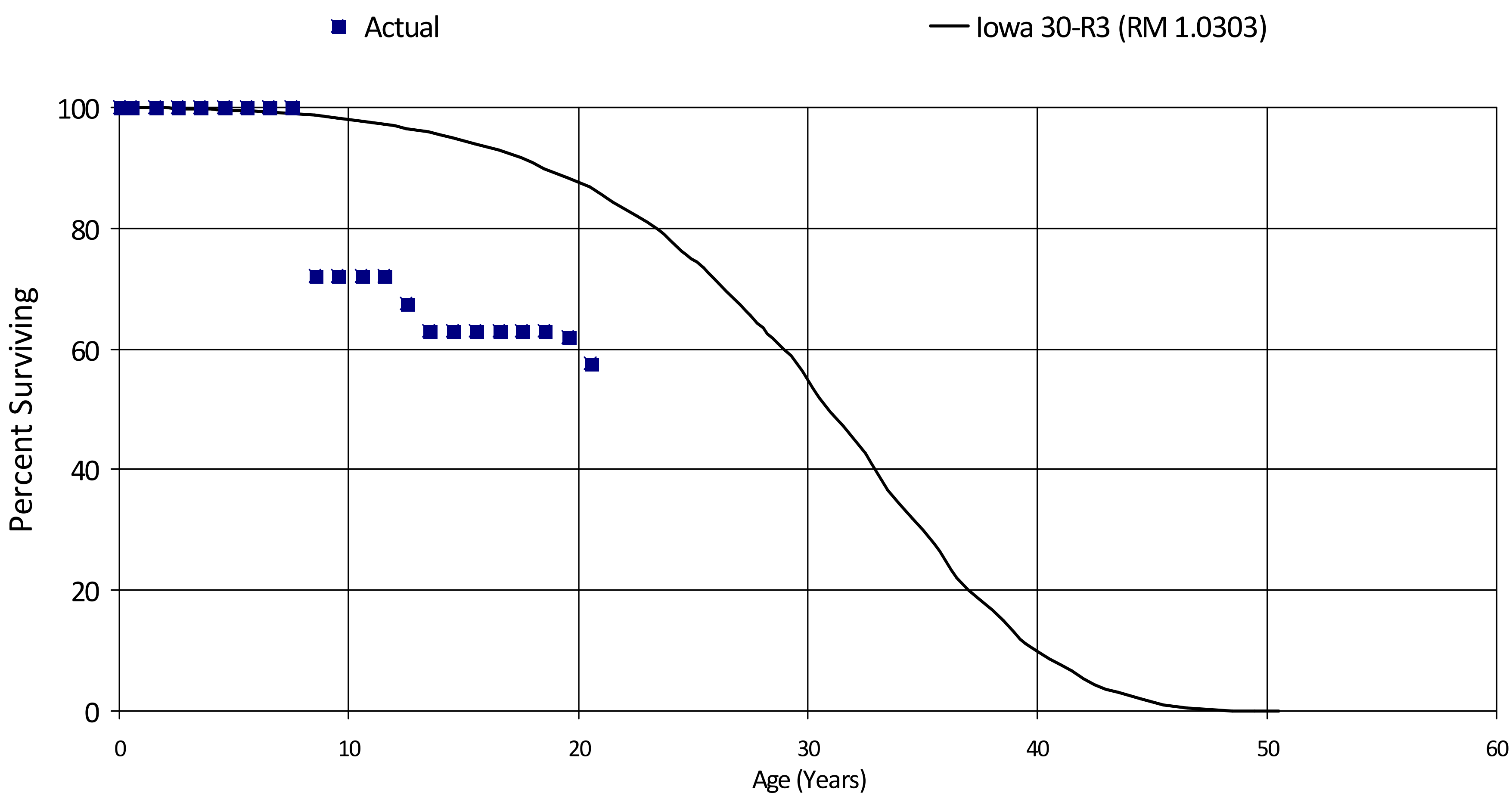
Totals:	463,356

BC Hydro Power Authority

Account 46701 - Heat Exchanger

Placement Band - 1994 - 2019 Experience Band - 2018 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 46701 - Heat Exchanger

Placement Band - 1994 - 2019   Experience Band - 2018 - 2020

RETIREMENT RATE ANALYSIS

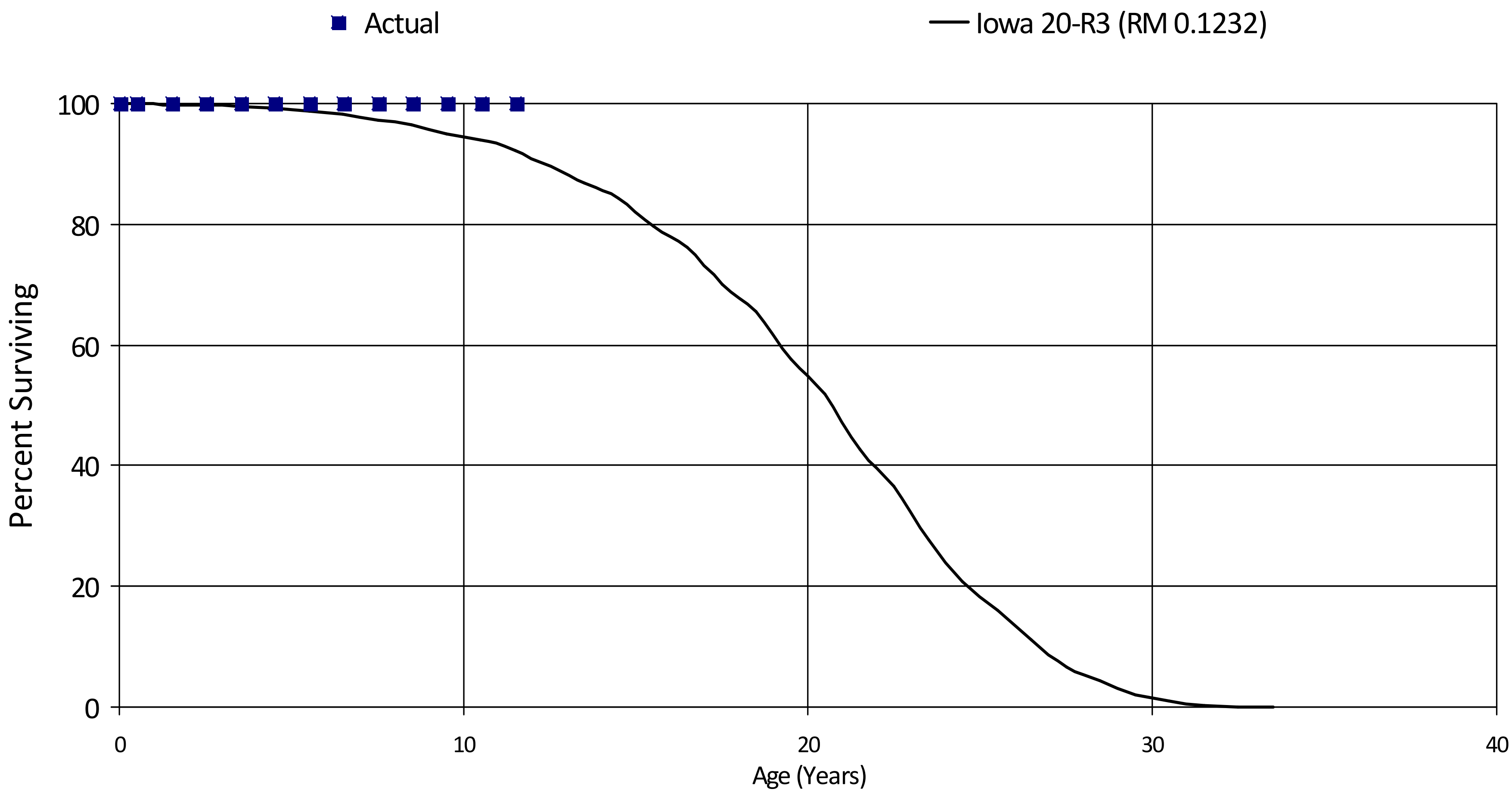
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	6,129,798	0	0.00000	1.00000	100.00
0.5	6,129,798	0	0.00000	1.00000	100.00
1.5	4,618,445	0	0.00000	1.00000	100.00
2.5	4,618,445	0	0.00000	1.00000	100.00
3.5	4,618,445	0	0.00000	1.00000	100.00
4.5	4,517,358	0	0.00000	1.00000	100.00
5.5	4,517,358	0	0.00000	1.00000	100.00
6.5	4,517,358	0	0.00000	1.00000	100.00
7.5	4,517,358	1,262,729	0.27953	0.72047	100.00
8.5	3,254,629	0	0.00000	1.00000	72.05
9.5	2,446,258	0	0.00000	1.00000	72.05
10.5	2,079,936	0	0.00000	1.00000	72.05
11.5	1,849,675	118,037	0.06382	0.93618	72.05
12.5	1,731,637	118,037	0.06816	0.93184	67.45
13.5	1,613,600	0	0.00000	1.00000	62.85
14.5	435,304	0	0.00000	1.00000	62.85
15.5	335,306	0	0.00000	1.00000	62.85
16.5	242,094	0	0.00000	1.00000	62.85
17.5	242,094	0	0.00000	1.00000	62.85
18.5	222,696	3,526	0.01583	0.98417	62.85
19.5	181,558	12,098	0.06663	0.93337	61.86
20.5	167,698	0	0.00000	1.00000	57.74
	Totals:	1,514,427			

BC Hydro Power Authority

Account 47001 - Intake, Air

Placement Band - 2008 - 2008   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 47001 - Intake, Air

Placement Band - 2008 - 2008   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

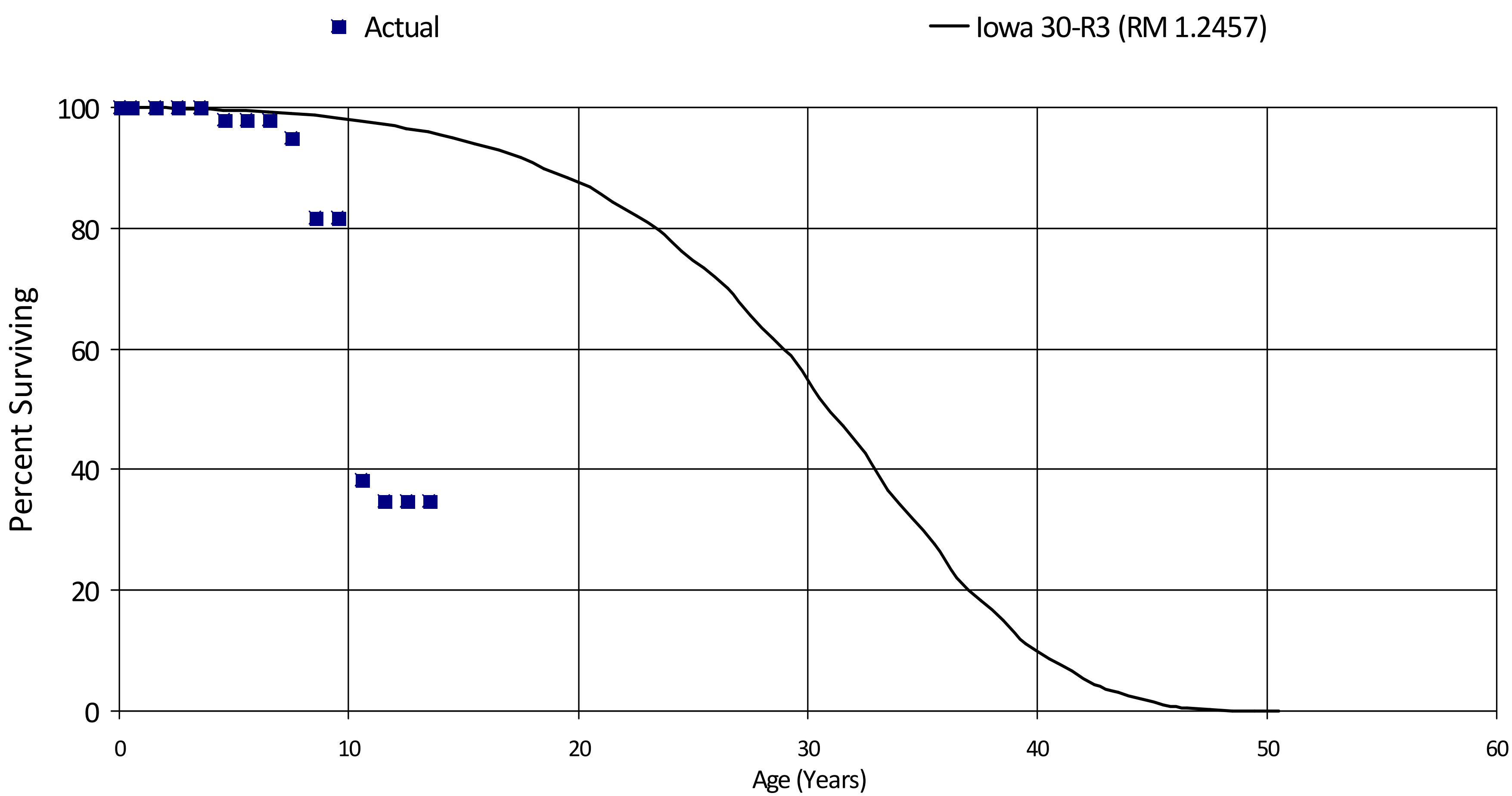
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	504,775	0	0.00000	1.00000	100.00
0.5	504,775	0	0.00000	1.00000	100.00
1.5	504,775	0	0.00000	1.00000	100.00
2.5	504,775	0	0.00000	1.00000	100.00
3.5	504,775	0	0.00000	1.00000	100.00
4.5	504,775	0	0.00000	1.00000	100.00
5.5	504,775	0	0.00000	1.00000	100.00
6.5	504,775	0	0.00000	1.00000	100.00
7.5	504,775	0	0.00000	1.00000	100.00
8.5	504,775	0	0.00000	1.00000	100.00
9.5	504,775	0	0.00000	1.00000	100.00
10.5	504,775	0	0.00000	1.00000	100.00
11.5	504,775	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 47201 - Turbine, Gas

Placement Band - 1976 - 2012 Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 47201 - Turbine, Gas

Placement Band - 1976 - 2012 Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

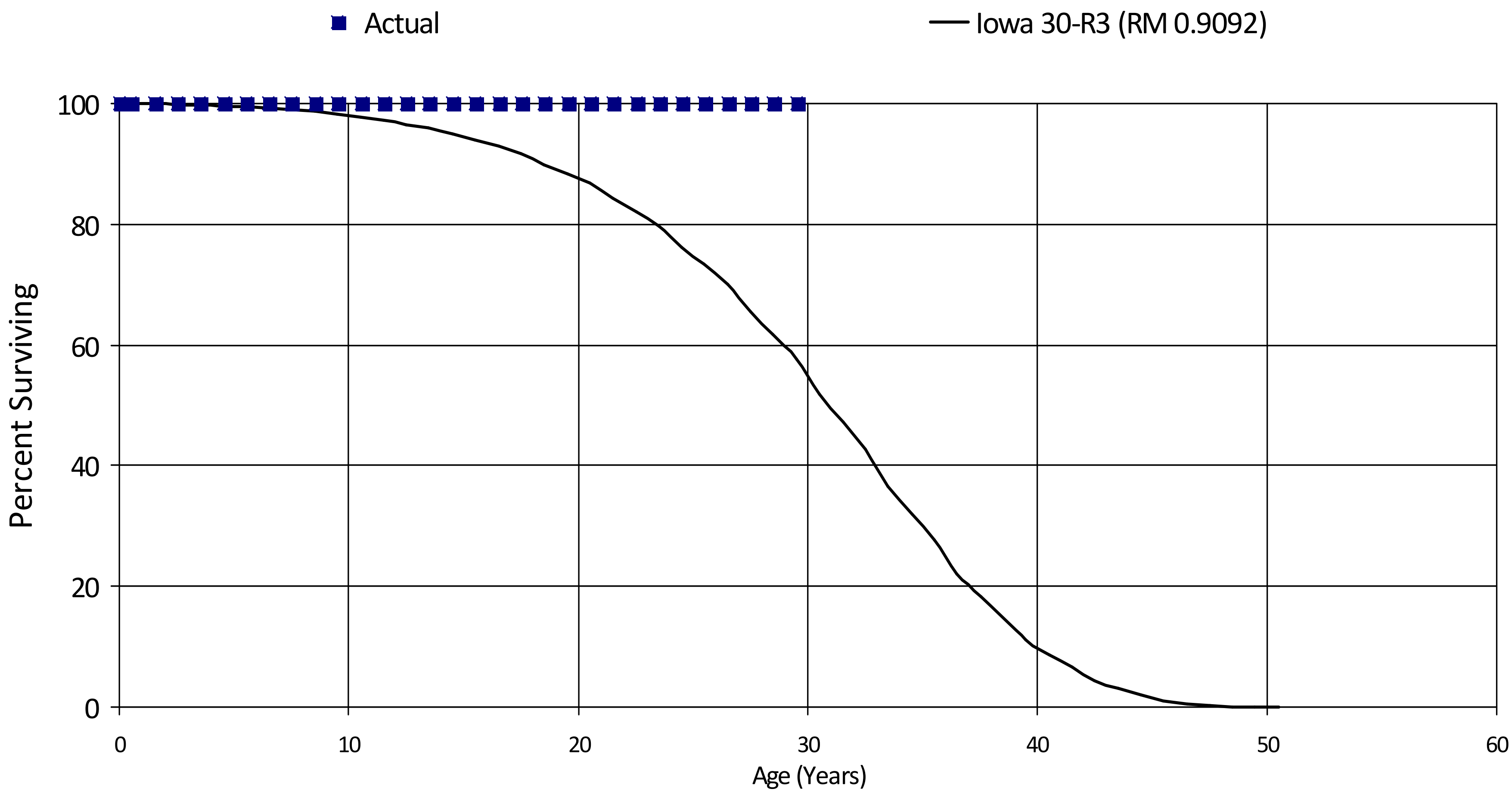
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	9,837,580	0	0.00000	1.00000	100.00
0.5	9,837,580	0	0.00000	1.00000	100.00
1.5	9,837,580	0	0.00000	1.00000	100.00
2.5	9,837,580	0	0.00000	1.00000	100.00
3.5	9,837,580	200,000	0.02033	0.97967	100.00
4.5	9,637,580	0	0.00000	1.00000	97.97
5.5	9,637,580	0	0.00000	1.00000	97.97
6.5	9,637,580	289,453	0.03003	0.96997	97.97
7.5	9,348,127	1,309,292	0.14006	0.85994	95.03
8.5	5,713,396	0	0.00000	1.00000	81.72
9.5	4,972,407	2,646,550	0.53225	0.46775	81.72
10.5	2,296,032	199,888	0.08706	0.91294	38.22
11.5	189,795	0	0.00000	1.00000	34.89
12.5	146,064	0	0.00000	1.00000	34.89
13.5	146,064	0	0.00000	1.00000	34.89
	Totals:	4,645,183			

BC Hydro Power Authority

Account 47401 - Fuel System

Placement Band - 1982 - 2018 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 47401 - Fuel System

Placement Band - 1982 - 2018 Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	3,355,087	0	0.00000	1.00000	100.00
0.5	3,355,087	0	0.00000	1.00000	100.00
1.5	3,355,087	0	0.00000	1.00000	100.00
2.5	3,167,600	0	0.00000	1.00000	100.00
3.5	3,167,600	0	0.00000	1.00000	100.00
4.5	3,167,600	0	0.00000	1.00000	100.00
5.5	3,167,600	0	0.00000	1.00000	100.00
6.5	3,157,205	0	0.00000	1.00000	100.00
7.5	3,157,205	0	0.00000	1.00000	100.00
8.5	3,157,205	0	0.00000	1.00000	100.00
9.5	3,157,205	0	0.00000	1.00000	100.00
10.5	3,153,935	0	0.00000	1.00000	100.00
11.5	2,146,136	0	0.00000	1.00000	100.00
12.5	2,146,136	0	0.00000	1.00000	100.00
13.5	1,539,887	0	0.00000	1.00000	100.00
14.5	788,868	0	0.00000	1.00000	100.00
15.5	579,254	0	0.00000	1.00000	100.00
16.5	455,334	0	0.00000	1.00000	100.00
17.5	173,800	0	0.00000	1.00000	100.00
18.5	173,800	0	0.00000	1.00000	100.00
19.5	173,800	0	0.00000	1.00000	100.00
20.5	173,800	0	0.00000	1.00000	100.00
21.5	173,800	0	0.00000	1.00000	100.00
22.5	142,562	0	0.00000	1.00000	100.00
23.5	142,562	0	0.00000	1.00000	100.00
24.5	142,562	0	0.00000	1.00000	100.00
25.5	142,392	0	0.00000	1.00000	100.00
26.5	101,645	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 47401 - Fuel System

Placement Band - 1982 - 2018 Experience Band - 2013 - 2020

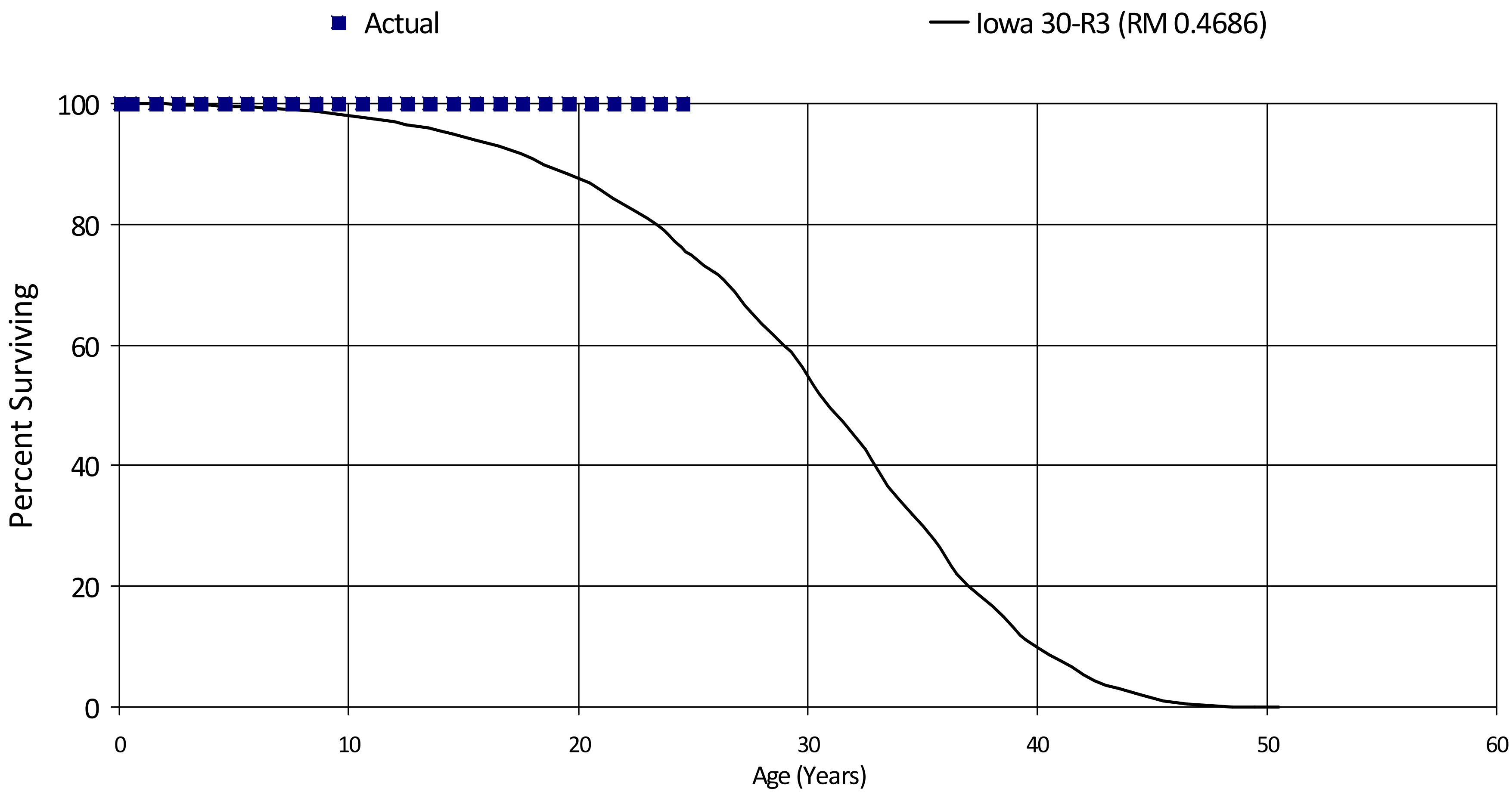
27.5	100,781	0	0.00000	1.00000	100.00
28.5	35,846	0	0.00000	1.00000	100.00
29.5	35,846	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 48001 - Coils, Stator

Placement Band - 1995 - 2009 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 48001 - Coils, Stator

Placement Band - 1995 - 2009   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

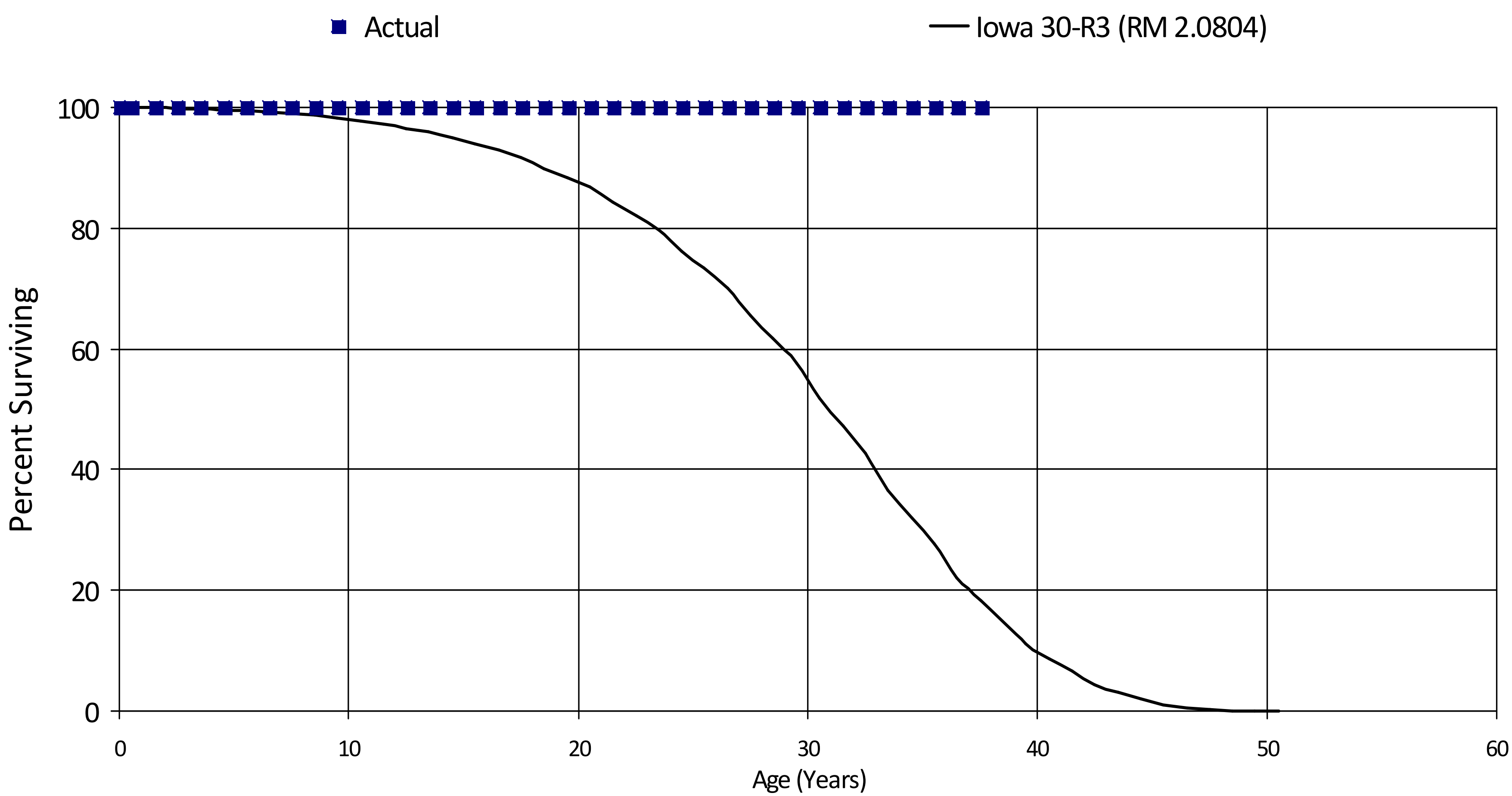
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	140,633	0	0.00000	1.00000	100.00
0.5	140,633	0	0.00000	1.00000	100.00
1.5	140,633	0	0.00000	1.00000	100.00
2.5	140,633	0	0.00000	1.00000	100.00
3.5	140,633	0	0.00000	1.00000	100.00
4.5	140,633	0	0.00000	1.00000	100.00
5.5	140,633	0	0.00000	1.00000	100.00
6.5	140,633	0	0.00000	1.00000	100.00
7.5	140,633	0	0.00000	1.00000	100.00
8.5	140,633	0	0.00000	1.00000	100.00
9.5	140,633	0	0.00000	1.00000	100.00
10.5	140,633	0	0.00000	1.00000	100.00
11.5	140,633	0	0.00000	1.00000	100.00
12.5	140,633	0	0.00000	1.00000	100.00
13.5	140,633	0	0.00000	1.00000	100.00
14.5	140,633	0	0.00000	1.00000	100.00
15.5	45,490	0	0.00000	1.00000	100.00
16.5	45,490	0	0.00000	1.00000	100.00
17.5	45,490	0	0.00000	1.00000	100.00
18.5	45,490	0	0.00000	1.00000	100.00
19.5	45,490	0	0.00000	1.00000	100.00
20.5	45,490	0	0.00000	1.00000	100.00
21.5	45,490	0	0.00000	1.00000	100.00
22.5	45,490	0	0.00000	1.00000	100.00
23.5	45,490	0	0.00000	1.00000	100.00
24.5	45,490	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 48002 - Rotor, Generator

Placement Band - 1982 - 2017 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 48002 - Rotor, Generator

Placement Band - 1982 - 2017   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	152,254	0	0.00000	1.00000	100.00
0.5	152,254	0	0.00000	1.00000	100.00
1.5	152,254	0	0.00000	1.00000	100.00
2.5	152,254	0	0.00000	1.00000	100.00
3.5	97,595	0	0.00000	1.00000	100.00
4.5	97,595	0	0.00000	1.00000	100.00
5.5	97,595	0	0.00000	1.00000	100.00
6.5	97,595	0	0.00000	1.00000	100.00
7.5	97,595	0	0.00000	1.00000	100.00
8.5	97,595	0	0.00000	1.00000	100.00
9.5	97,595	0	0.00000	1.00000	100.00
10.5	97,595	0	0.00000	1.00000	100.00
11.5	97,595	0	0.00000	1.00000	100.00
12.5	97,595	0	0.00000	1.00000	100.00
13.5	97,595	0	0.00000	1.00000	100.00
14.5	97,595	0	0.00000	1.00000	100.00
15.5	2,453	0	0.00000	1.00000	100.00
16.5	2,453	0	0.00000	1.00000	100.00
17.5	2,453	0	0.00000	1.00000	100.00
18.5	2,453	0	0.00000	1.00000	100.00
19.5	2,453	0	0.00000	1.00000	100.00
20.5	2,453	0	0.00000	1.00000	100.00
21.5	2,453	0	0.00000	1.00000	100.00
22.5	2,453	0	0.00000	1.00000	100.00
23.5	2,453	0	0.00000	1.00000	100.00
24.5	2,453	0	0.00000	1.00000	100.00
25.5	2,453	0	0.00000	1.00000	100.00
26.5	2,453	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 48002 - Rotor, Generator

Placement Band - 1982 - 2017   Experience Band - 2020 - 2020

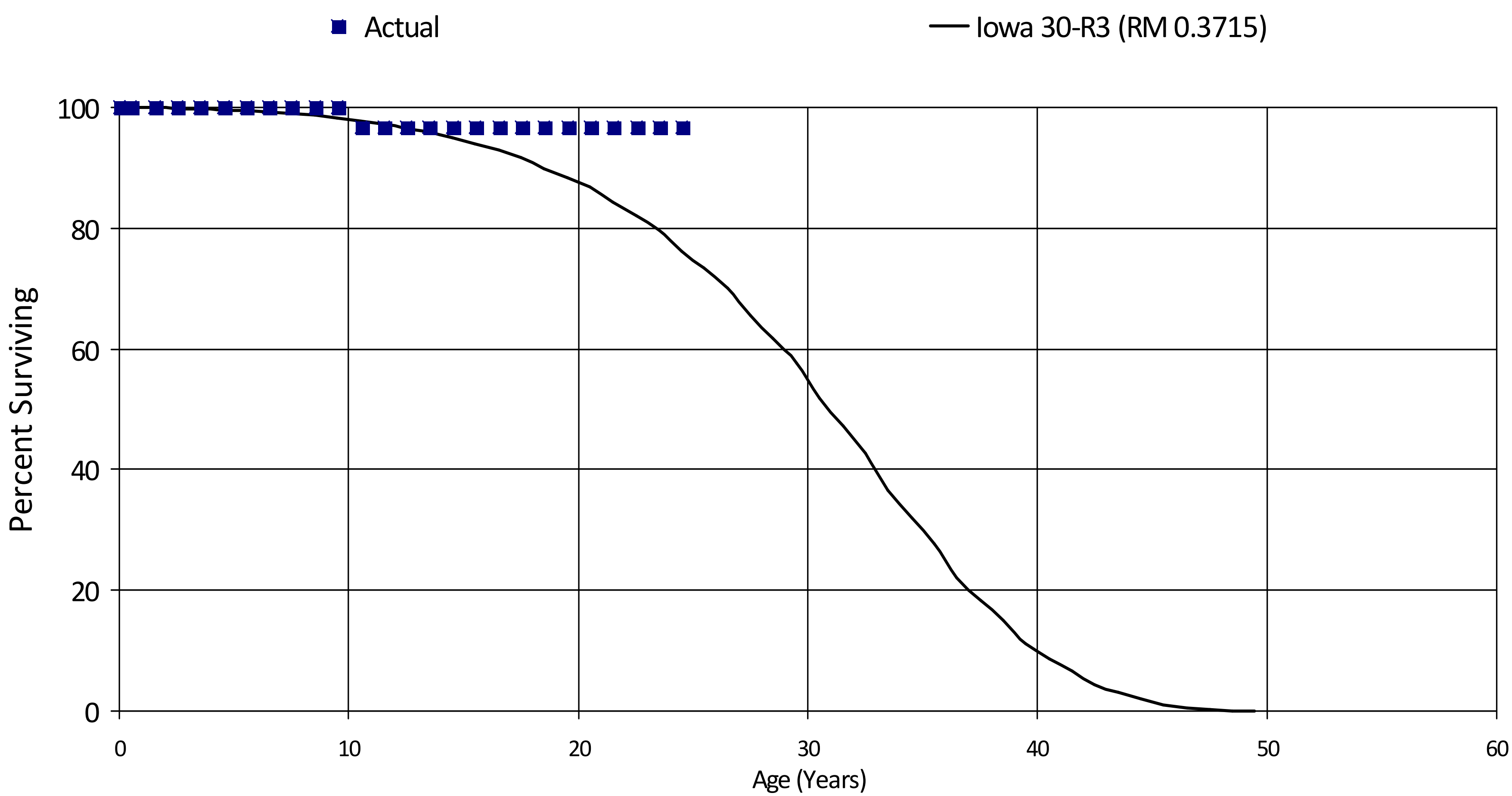
27.5	2,453	0	0.00000	1.00000	100.00
28.5	2,453	0	0.00000	1.00000	100.00
29.5	2,453	0	0.00000	1.00000	100.00
30.5	2,453	0	0.00000	1.00000	100.00
31.5	2,453	0	0.00000	1.00000	100.00
32.5	2,453	0	0.00000	1.00000	100.00
33.5	2,453	0	0.00000	1.00000	100.00
34.5	2,453	0	0.00000	1.00000	100.00
35.5	2,453	0	0.00000	1.00000	100.00
36.5	2,453	0	0.00000	1.00000	100.00
37.5	2,453	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 48003 - Generator, Composite Pool

Placement Band - 1970 - 2020 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 48003 - Generator, Composite Pool

Placement Band - 1970 - 2020 Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

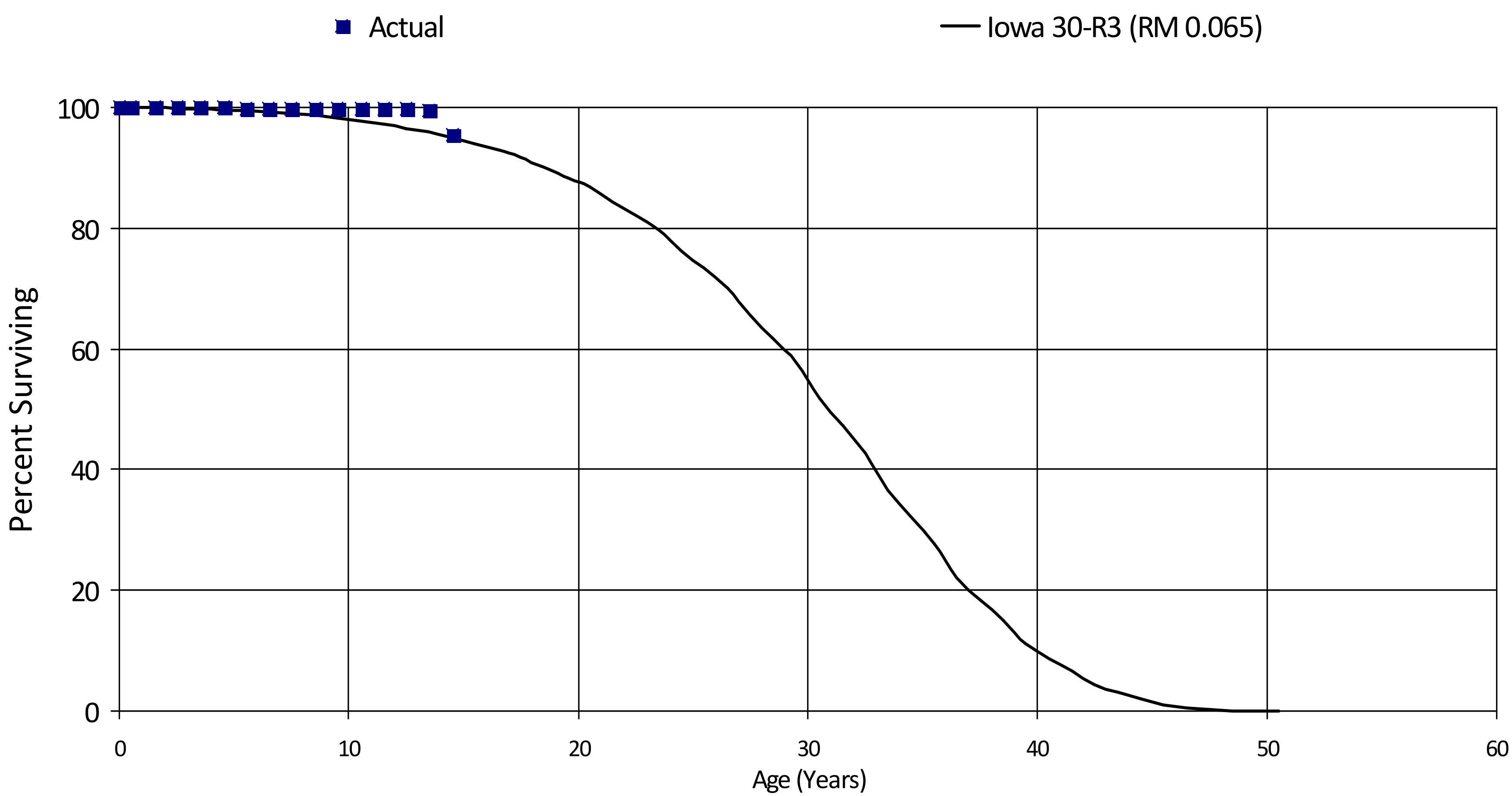
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	5,513,595	0	0.00000	1.00000	100.00
0.5	5,297,976	0	0.00000	1.00000	100.00
1.5	5,297,976	0	0.00000	1.00000	100.00
2.5	3,759,553	0	0.00000	1.00000	100.00
3.5	3,759,553	0	0.00000	1.00000	100.00
4.5	3,759,553	0	0.00000	1.00000	100.00
5.5	3,759,553	0	0.00000	1.00000	100.00
6.5	3,759,553	0	0.00000	1.00000	100.00
7.5	3,759,553	0	0.00000	1.00000	100.00
8.5	3,759,553	0	0.00000	1.00000	100.00
9.5	3,768,636	119,655	0.03175	0.96825	100.00
10.5	3,648,981	0	0.00000	1.00000	96.82
11.5	3,648,981	0	0.00000	1.00000	96.82
12.5	1,096,276	0	0.00000	1.00000	96.82
13.5	1,096,276	0	0.00000	1.00000	96.82
14.5	925,743	0	0.00000	1.00000	96.82
15.5	761,827	0	0.00000	1.00000	96.82
16.5	679,144	0	0.00000	1.00000	96.82
17.5	242,842	0	0.00000	1.00000	96.82
18.5	242,842	0	0.00000	1.00000	96.82
19.5	242,842	0	0.00000	1.00000	96.82
20.5	235,145	0	0.00000	1.00000	96.82
21.5	99,346	0	0.00000	1.00000	96.82
22.5	97,760	0	0.00000	1.00000	96.82
23.5	86,311	0	0.00000	1.00000	96.82
24.5	86,311	0	0.00000	1.00000	96.82
	Totals:	119,655			

BC Hydro Power Authority

Account 48004 - Generator, Diesel

Placement Band - 2002 - 2020   Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 48004 - Generator, Diesel

Placement Band - 2002 - 2020   Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

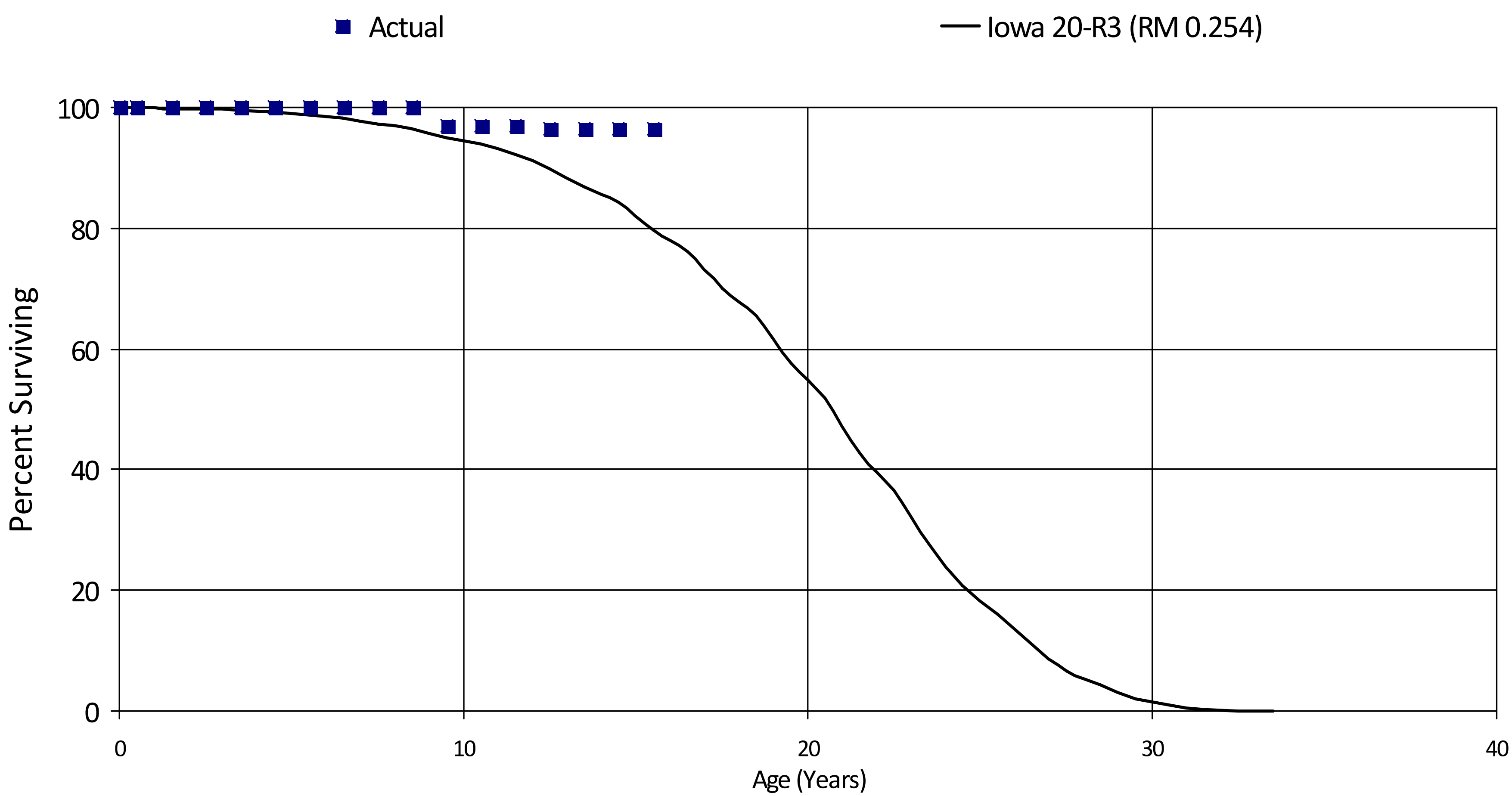
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	67,357,953	0	0.00000	1.00000	100.00
0.5	65,737,878	0	0.00000	1.00000	100.00
1.5	58,400,357	0	0.00000	1.00000	100.00
2.5	53,239,370	0	0.00000	1.00000	100.00
3.5	51,882,893	0	0.00000	1.00000	100.00
4.5	43,495,315	68,332	0.00157	0.99843	100.00
5.5	42,297,175	0	0.00000	1.00000	99.84
6.5	36,038,009	0	0.00000	1.00000	99.84
7.5	29,635,218	0	0.00000	1.00000	99.84
8.5	27,741,530	0	0.00000	1.00000	99.84
9.5	19,781,024	0	0.00000	1.00000	99.84
10.5	16,932,825	0	0.00000	1.00000	99.84
11.5	7,823,848	0	0.00000	1.00000	99.84
12.5	6,011,443	18,208	0.00303	0.99697	99.84
13.5	4,597,285	192,548	0.04188	0.95812	99.54
14.5	2,688,366	0	0.00000	1.00000	95.37
	Totals:	279,088			

BC Hydro Power Authority

Account 49001 - Pump

Placement Band - 1960 - 2018 Experience Band - 2015 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 49001 - Pump

Placement Band - 1960 - 2018   Experience Band - 2015 - 2020

RETIREMENT RATE ANALYSIS

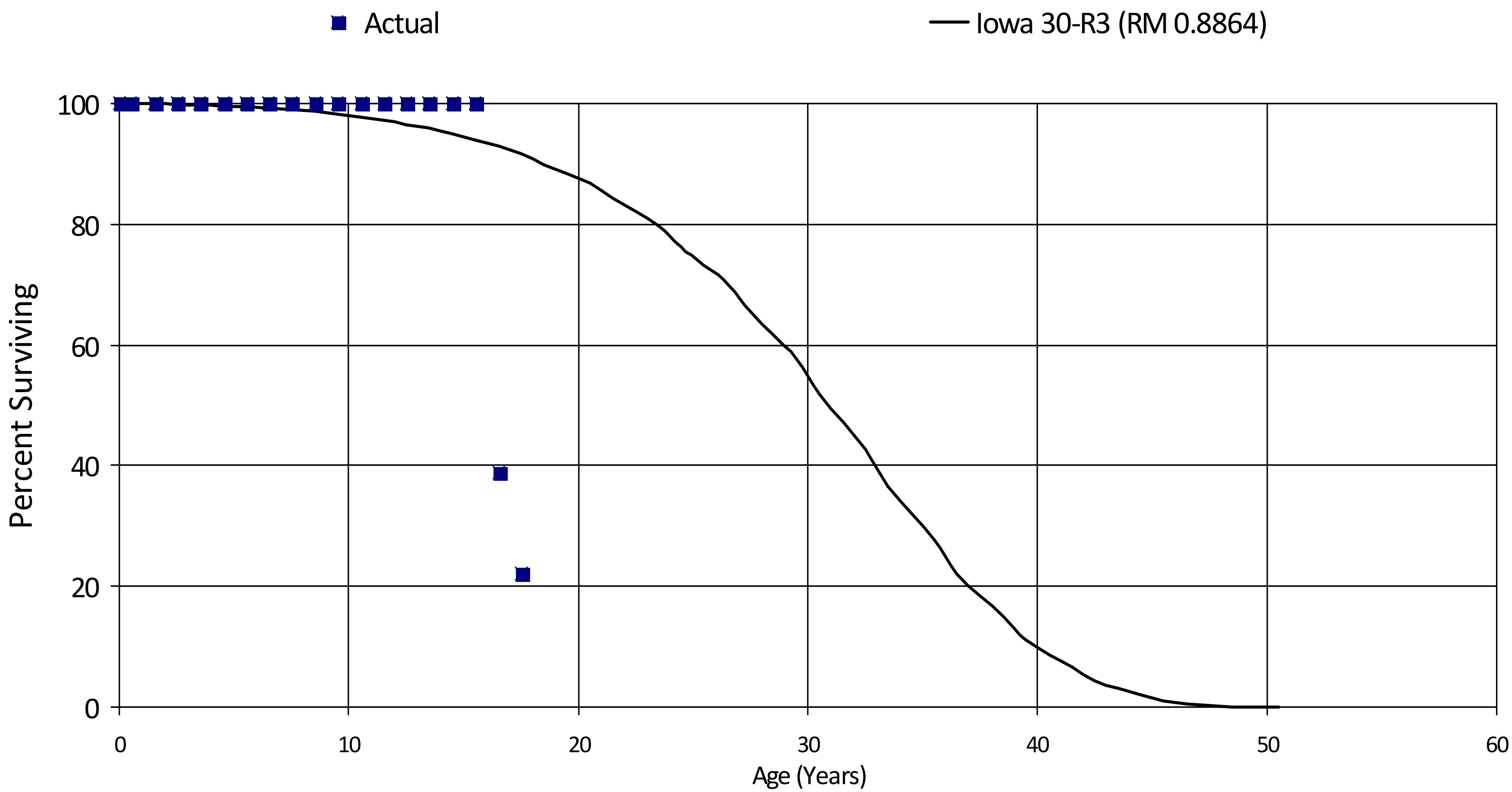
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	12,915,483	0	0.00000	1.00000	100.00
0.5	12,915,483	0	0.00000	1.00000	100.00
1.5	12,915,483	0	0.00000	1.00000	100.00
2.5	11,599,590	0	0.00000	1.00000	100.00
3.5	11,448,746	0	0.00000	1.00000	100.00
4.5	11,441,658	0	0.00000	1.00000	100.00
5.5	11,377,036	0	0.00000	1.00000	100.00
6.5	11,142,825	0	0.00000	1.00000	100.00
7.5	11,142,825	0	0.00000	1.00000	100.00
8.5	1,761,155	51,536	0.02926	0.97074	100.00
9.5	1,709,620	0	0.00000	1.00000	97.07
10.5	1,457,603	0	0.00000	1.00000	97.07
11.5	1,457,603	7,546	0.00518	0.99482	97.07
12.5	1,450,057	0	0.00000	1.00000	96.57
13.5	1,361,336	0	0.00000	1.00000	96.57
14.5	698,571	0	0.00000	1.00000	96.57
15.5	454,903	0	0.00000	1.00000	96.57
	Totals:	59,082			

BC Hydro Power Authority

Account 49002 - Motor

Placement Band - 1995 - 2019   Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 49002 - Motor

Placement Band - 1995 - 2019   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

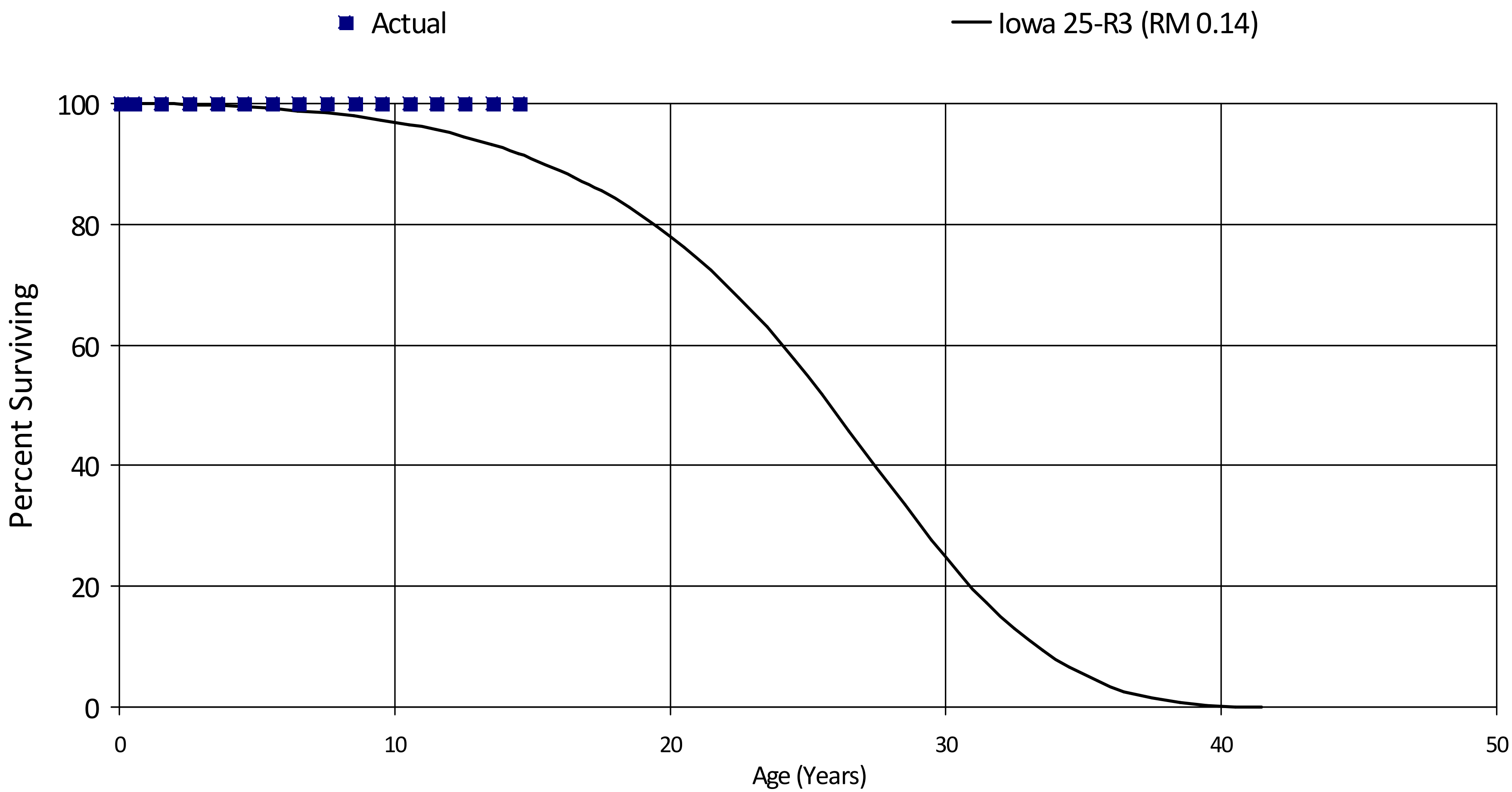
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,422,178	0	0.00000	1.00000	100.00
0.5	1,422,178	0	0.00000	1.00000	100.00
1.5	1,406,556	0	0.00000	1.00000	100.00
2.5	1,406,556	0	0.00000	1.00000	100.00
3.5	1,391,800	0	0.00000	1.00000	100.00
4.5	1,391,800	0	0.00000	1.00000	100.00
5.5	1,391,800	0	0.00000	1.00000	100.00
6.5	1,391,800	0	0.00000	1.00000	100.00
7.5	1,391,800	0	0.00000	1.00000	100.00
8.5	1,293,343	0	0.00000	1.00000	100.00
9.5	352,906	0	0.00000	1.00000	100.00
10.5	270,929	0	0.00000	1.00000	100.00
11.5	270,928	0	0.00000	1.00000	100.00
12.5	270,928	0	0.00000	1.00000	100.00
13.5	243,655	0	0.00000	1.00000	100.00
14.5	243,655	0	0.00000	1.00000	100.00
15.5	243,655	148,744	0.61047	0.38953	100.00
16.5	61,997	26,891	0.43375	0.56625	38.95
17.5	35,106	0	0.00000	1.00000	22.06
	Totals:	175,635			

BC Hydro Power Authority

Account 49101 - Fan & Motor

Placement Band - 2005 - 2016 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 49101 - Fan & Motor

Placement Band - 2005 - 2016   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

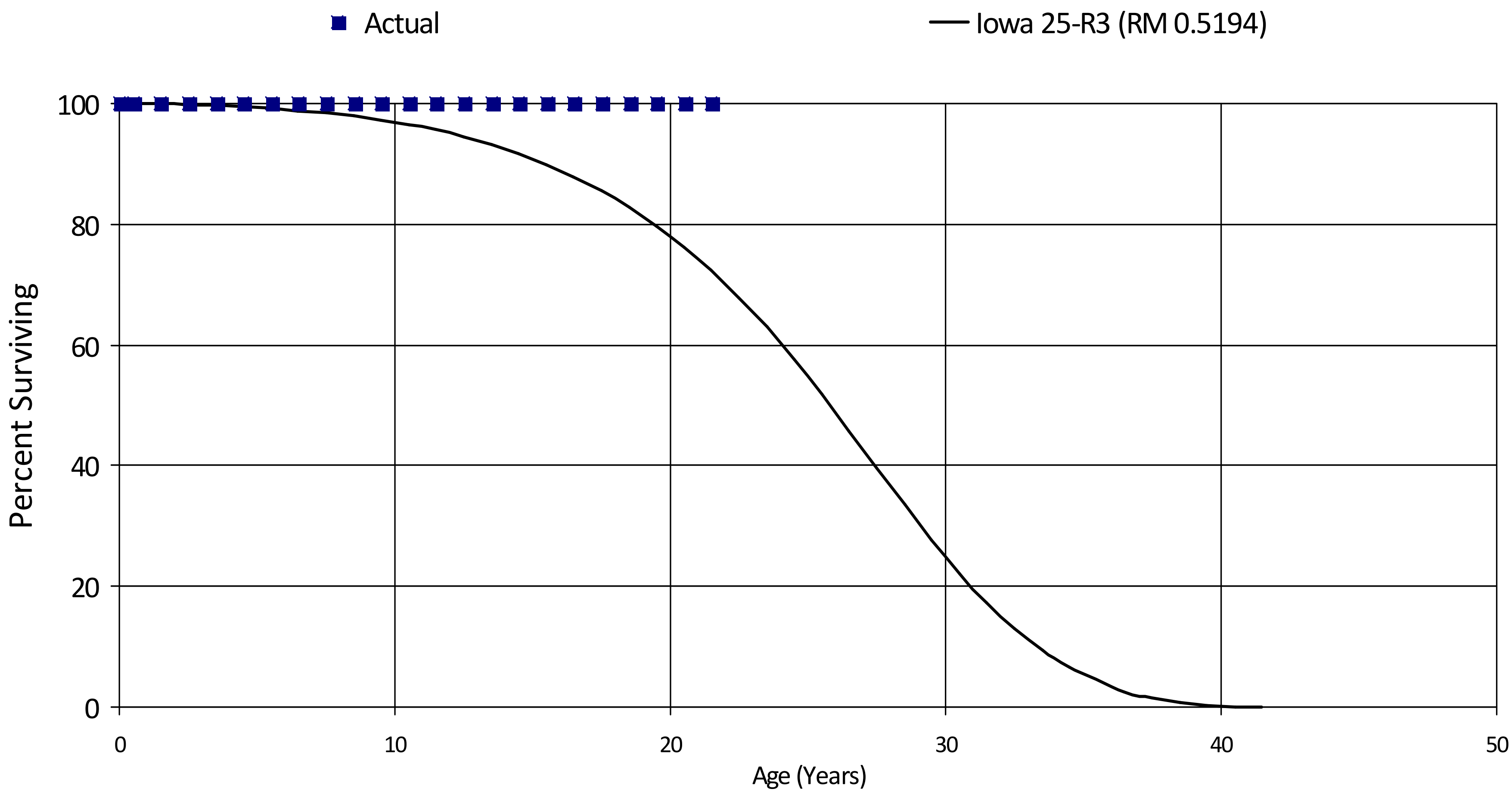
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	444,141	0	0.00000	1.00000	100.00
0.5	444,141	0	0.00000	1.00000	100.00
1.5	444,141	0	0.00000	1.00000	100.00
2.5	444,141	0	0.00000	1.00000	100.00
3.5	444,141	0	0.00000	1.00000	100.00
4.5	382,152	0	0.00000	1.00000	100.00
5.5	382,152	0	0.00000	1.00000	100.00
6.5	382,152	0	0.00000	1.00000	100.00
7.5	382,152	0	0.00000	1.00000	100.00
8.5	382,152	0	0.00000	1.00000	100.00
9.5	382,152	0	0.00000	1.00000	100.00
10.5	382,152	0	0.00000	1.00000	100.00
11.5	49,075	0	0.00000	1.00000	100.00
12.5	49,075	0	0.00000	1.00000	100.00
13.5	49,075	0	0.00000	1.00000	100.00
14.5	18,530	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 49201 - Vacuum System

Placement Band - 1985 - 1999   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 49201 - Vacuum System

Placement Band - 1985 - 1999   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

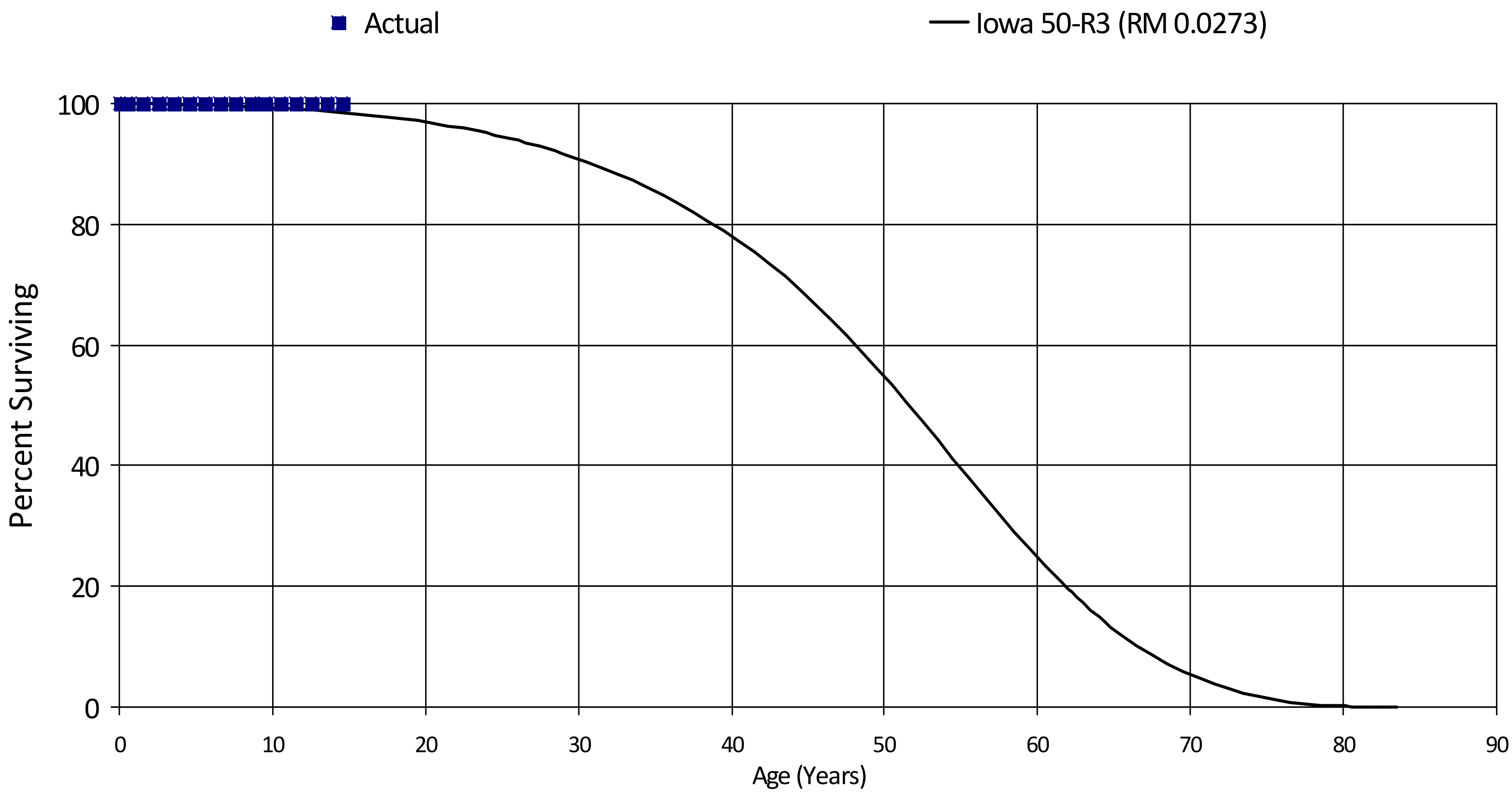
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	18,310	0	0.00000	1.00000	100.00
0.5	18,310	0	0.00000	1.00000	100.00
1.5	18,310	0	0.00000	1.00000	100.00
2.5	18,310	0	0.00000	1.00000	100.00
3.5	18,310	0	0.00000	1.00000	100.00
4.5	18,310	0	0.00000	1.00000	100.00
5.5	18,310	0	0.00000	1.00000	100.00
6.5	18,310	0	0.00000	1.00000	100.00
7.5	18,310	0	0.00000	1.00000	100.00
8.5	18,310	0	0.00000	1.00000	100.00
9.5	18,310	0	0.00000	1.00000	100.00
10.5	18,310	0	0.00000	1.00000	100.00
11.5	18,310	0	0.00000	1.00000	100.00
12.5	18,310	0	0.00000	1.00000	100.00
13.5	18,310	0	0.00000	1.00000	100.00
14.5	18,310	0	0.00000	1.00000	100.00
15.5	18,310	0	0.00000	1.00000	100.00
16.5	18,310	0	0.00000	1.00000	100.00
17.5	18,310	0	0.00000	1.00000	100.00
18.5	18,310	0	0.00000	1.00000	100.00
19.5	18,310	0	0.00000	1.00000	100.00
20.5	18,310	0	0.00000	1.00000	100.00
21.5	10,233	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 51001 - Condensor, Synchronous, Rotary

Placement Band - 1957 - 2017 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 51001 - Condensor, Synchronous, Rotary

Placement Band - 1957 - 2017   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

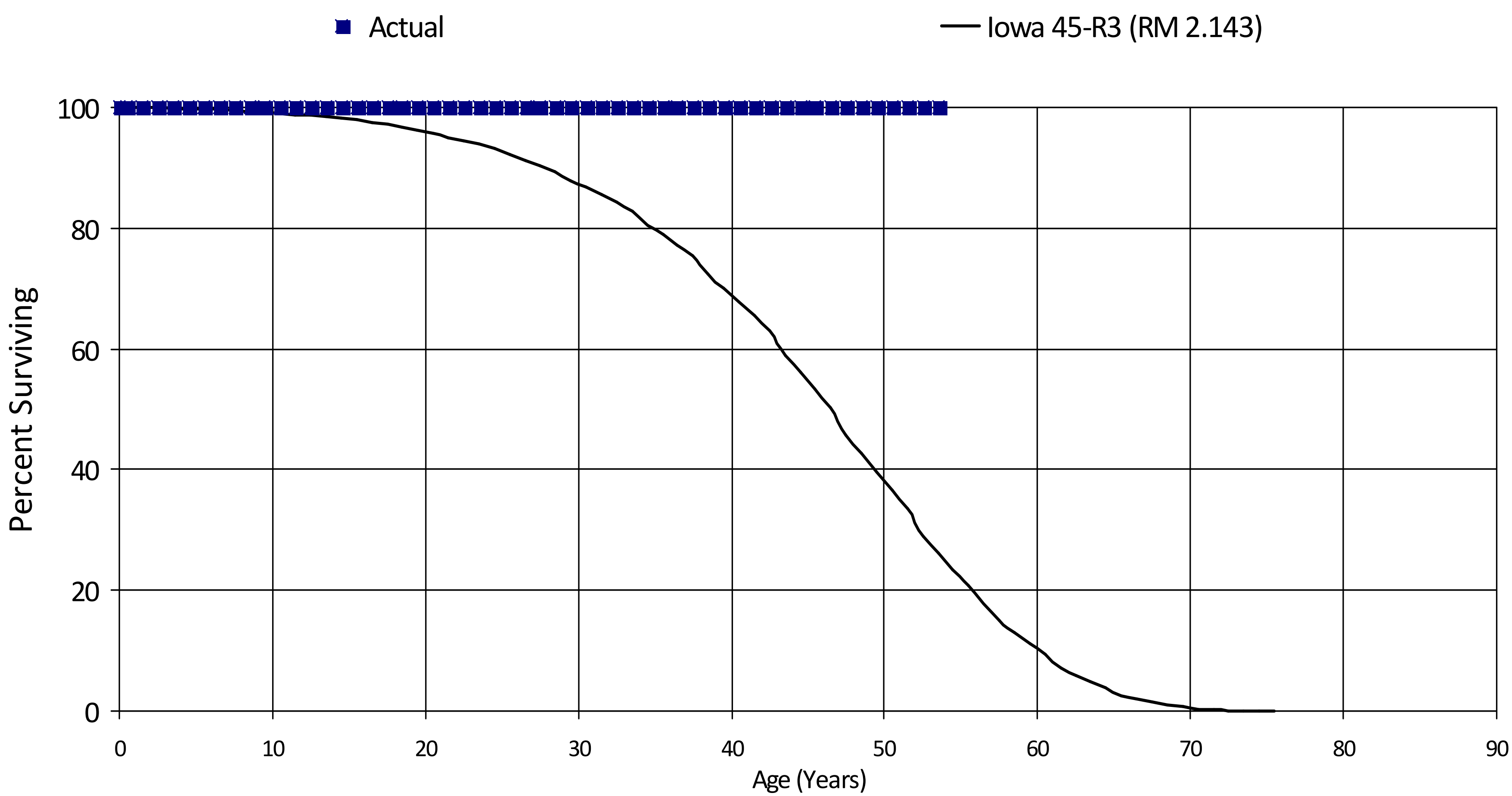
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	18,567,264	0	0.00000	1.00000	100.00
0.5	18,567,264	0	0.00000	1.00000	100.00
1.5	18,567,264	0	0.00000	1.00000	100.00
2.5	18,567,264	0	0.00000	1.00000	100.00
3.5	16,173,872	0	0.00000	1.00000	100.00
4.5	16,173,872	0	0.00000	1.00000	100.00
5.5	6,144,118	0	0.00000	1.00000	100.00
6.5	6,144,118	0	0.00000	1.00000	100.00
7.5	6,144,118	0	0.00000	1.00000	100.00
8.5	570,783	0	0.00000	1.00000	100.00
9.5	570,783	0	0.00000	1.00000	100.00
10.5	570,783	0	0.00000	1.00000	100.00
11.5	570,783	0	0.00000	1.00000	100.00
12.5	570,783	0	0.00000	1.00000	100.00
13.5	570,783	0	0.00000	1.00000	100.00
14.5	570,783	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 51002 - Condensor, Synchronous, Static

Placement Band - 1964 - 2008   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 51002 - Condensor, Synchronous, Static

Placement Band - 1964 - 2008   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	14,658,664	0	0.00000	1.00000	100.00
0.5	14,658,664	0	0.00000	1.00000	100.00
1.5	14,658,664	0	0.00000	1.00000	100.00
2.5	14,658,664	0	0.00000	1.00000	100.00
3.5	14,658,664	0	0.00000	1.00000	100.00
4.5	14,658,664	0	0.00000	1.00000	100.00
5.5	14,658,664	0	0.00000	1.00000	100.00
6.5	14,658,664	0	0.00000	1.00000	100.00
7.5	14,658,664	0	0.00000	1.00000	100.00
8.5	14,658,664	0	0.00000	1.00000	100.00
9.5	14,658,664	0	0.00000	1.00000	100.00
10.5	14,658,664	0	0.00000	1.00000	100.00
11.5	14,658,664	0	0.00000	1.00000	100.00
12.5	12,732,446	0	0.00000	1.00000	100.00
13.5	12,732,446	0	0.00000	1.00000	100.00
14.5	12,732,446	0	0.00000	1.00000	100.00
15.5	12,732,446	0	0.00000	1.00000	100.00
16.5	12,732,446	0	0.00000	1.00000	100.00
17.5	12,732,446	0	0.00000	1.00000	100.00
18.5	12,732,446	0	0.00000	1.00000	100.00
19.5	12,732,446	0	0.00000	1.00000	100.00
20.5	12,732,446	0	0.00000	1.00000	100.00
21.5	12,732,446	0	0.00000	1.00000	100.00
22.5	12,732,446	0	0.00000	1.00000	100.00
23.5	12,732,446	0	0.00000	1.00000	100.00
24.5	12,732,446	0	0.00000	1.00000	100.00
25.5	12,732,446	0	0.00000	1.00000	100.00
26.5	12,732,446	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 51002 - Condensor, Synchronous, Static

Placement Band - 1964 - 2008   Experience Band - 2020 - 2020

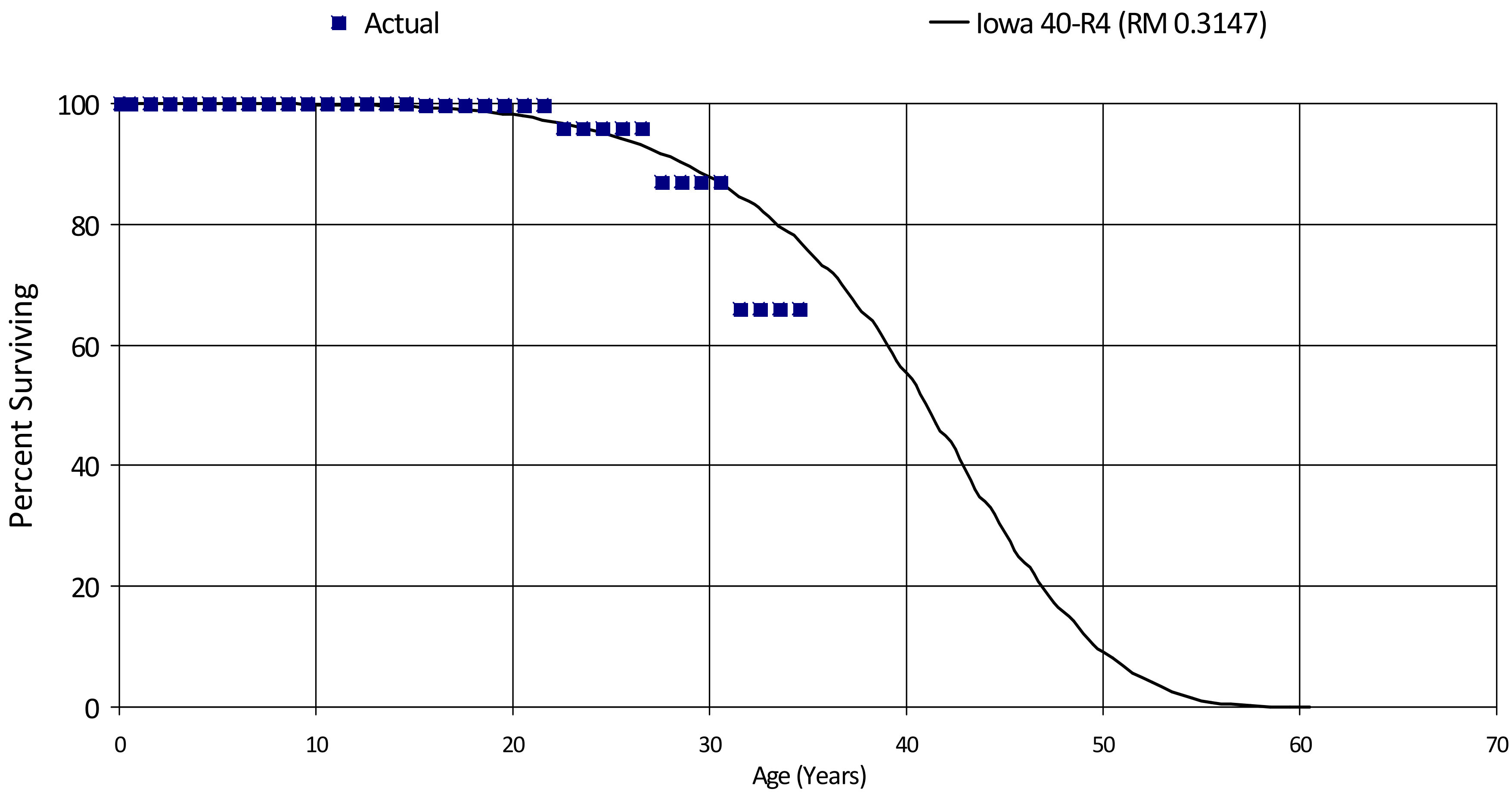
27.5	12,732,446	0	0.00000	1.00000	100.00
28.5	12,732,446	0	0.00000	1.00000	100.00
29.5	12,732,446	0	0.00000	1.00000	100.00
30.5	12,727,855	0	0.00000	1.00000	100.00
31.5	12,727,855	0	0.00000	1.00000	100.00
32.5	12,727,855	0	0.00000	1.00000	100.00
33.5	12,727,855	0	0.00000	1.00000	100.00
34.5	12,727,855	0	0.00000	1.00000	100.00
35.5	12,727,855	0	0.00000	1.00000	100.00
36.5	12,727,855	0	0.00000	1.00000	100.00
37.5	12,727,855	0	0.00000	1.00000	100.00
38.5	12,727,855	0	0.00000	1.00000	100.00
39.5	12,727,855	0	0.00000	1.00000	100.00
40.5	12,727,855	0	0.00000	1.00000	100.00
41.5	12,727,855	0	0.00000	1.00000	100.00
42.5	12,718,524	0	0.00000	1.00000	100.00
43.5	12,718,524	0	0.00000	1.00000	100.00
44.5	12,718,524	0	0.00000	1.00000	100.00
45.5	7,395,650	0	0.00000	1.00000	100.00
46.5	7,395,650	0	0.00000	1.00000	100.00
47.5	7,395,650	0	0.00000	1.00000	100.00
48.5	7,395,650	0	0.00000	1.00000	100.00
49.5	7,395,650	0	0.00000	1.00000	100.00
50.5	7,395,650	0	0.00000	1.00000	100.00
51.5	7,395,650	0	0.00000	1.00000	100.00
52.5	7,395,650	0	0.00000	1.00000	100.00
53.5	7,395,650	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 52101 - Transformer, Generator, Stepup

Placement Band - 1939 - 2020   Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52101 - Transformer, Generator, Stepup

Placement Band - 1939 - 2020   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	164,324,058	0	0.00000	1.00000	100.00
0.5	154,450,005	0	0.00000	1.00000	100.00
1.5	142,688,657	0	0.00000	1.00000	100.00
2.5	116,808,118	0	0.00000	1.00000	100.00
3.5	114,207,342	0	0.00000	1.00000	100.00
4.5	108,397,422	0	0.00000	1.00000	100.00
5.5	69,729,858	0	0.00000	1.00000	100.00
6.5	63,311,054	0	0.00000	1.00000	100.00
7.5	59,765,981	0	0.00000	1.00000	100.00
8.5	59,462,798	0	0.00000	1.00000	100.00
9.5	55,892,531	0	0.00000	1.00000	100.00
10.5	55,714,300	0	0.00000	1.00000	100.00
11.5	36,014,743	0	0.00000	1.00000	100.00
12.5	36,014,743	0	0.00000	1.00000	100.00
13.5	36,014,743	0	0.00000	1.00000	100.00
14.5	34,205,909	52,466	0.00153	0.99847	100.00
15.5	28,797,858	0	0.00000	1.00000	99.85
16.5	12,909,015	0	0.00000	1.00000	99.85
17.5	12,490,782	0	0.00000	1.00000	99.85
18.5	11,642,071	0	0.00000	1.00000	99.85
19.5	11,139,786	0	0.00000	1.00000	99.85
20.5	10,308,115	0	0.00000	1.00000	99.85
21.5	9,447,582	360,389	0.03815	0.96185	99.85
22.5	6,402,558	0	0.00000	1.00000	96.04
23.5	5,577,672	0	0.00000	1.00000	96.04
24.5	4,948,816	0	0.00000	1.00000	96.04
25.5	4,948,816	0	0.00000	1.00000	96.04
26.5	4,292,682	401,981	0.09364	0.90636	96.04

BC Hydro Power Authority

Account 52101 - Transformer, Generator, Stepup

Placement Band - 1939 - 2020 Experience Band - 2012 - 2020

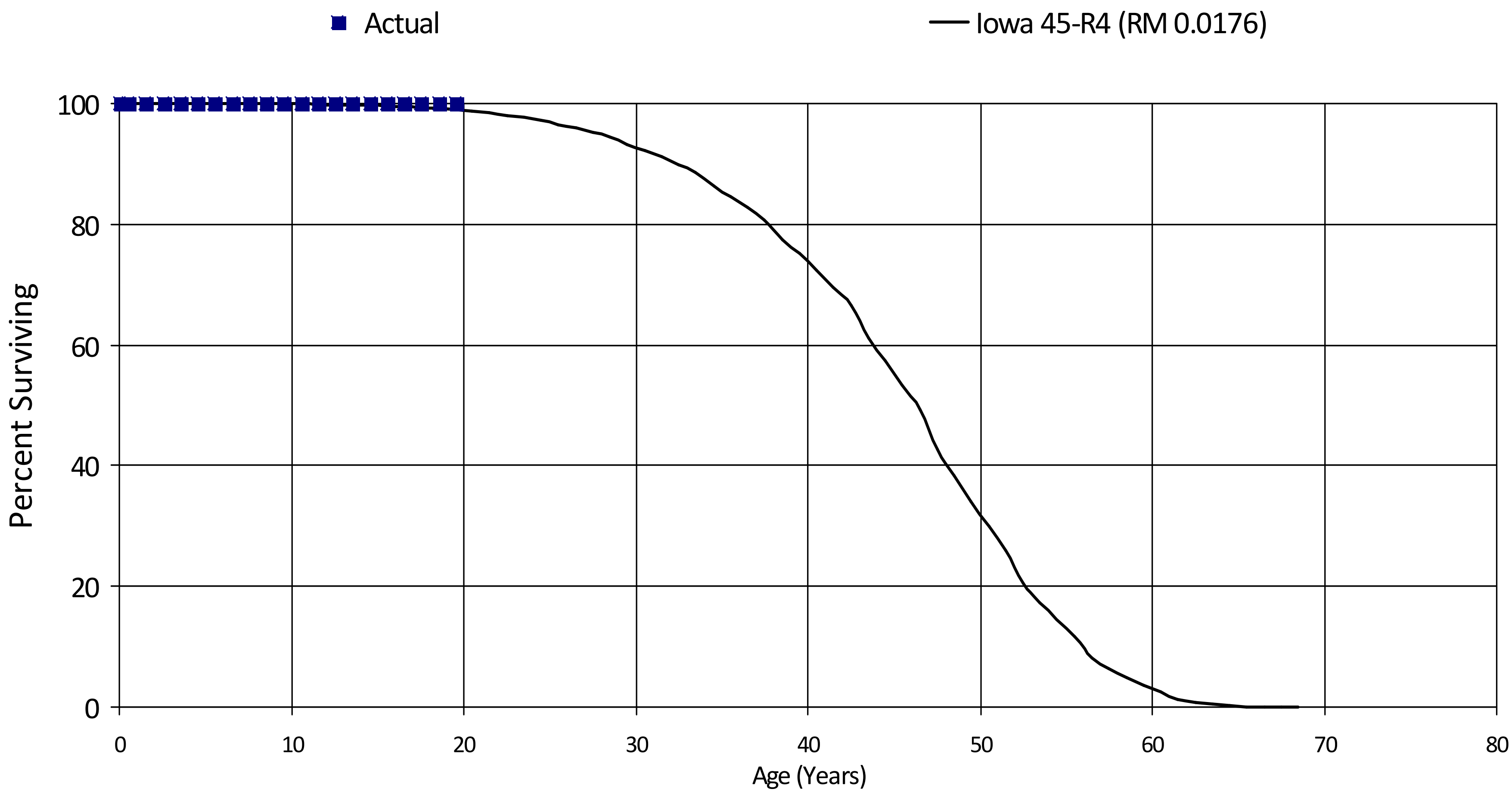
27.5	3,890,701	0	0.00000	1.00000	87.05
28.5	3,865,680	0	0.00000	1.00000	87.05
29.5	3,865,680	0	0.00000	1.00000	87.05
30.5	3,865,680	930,332	0.24066	0.75934	87.05
31.5	2,935,348	0	0.00000	1.00000	66.10
32.5	2,935,348	0	0.00000	1.00000	66.10
33.5	2,935,348	0	0.00000	1.00000	66.10
34.5	2,935,348	0	0.00000	1.00000	66.10
	Totals:	1,745,168			

BC Hydro Power Authority

Account 52102 - Transformer, Auto, Bulk System

Placement Band - 1966 - 2018 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52102 - Transformer, Auto, Bulk System

Placement Band - 1966 - 2018   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

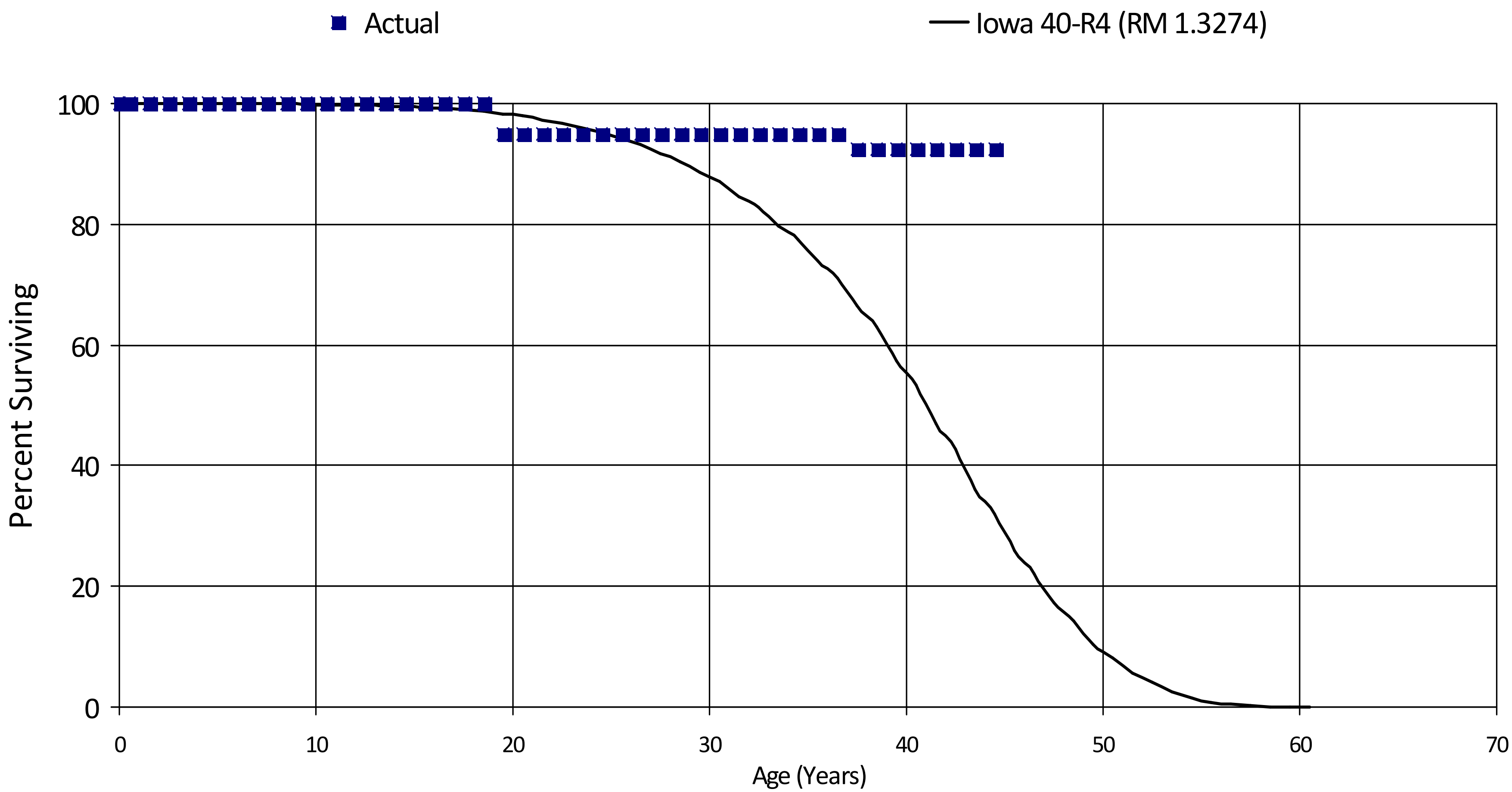
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	60,038,782	0	0.00000	1.00000	100.00
0.5	60,038,782	0	0.00000	1.00000	100.00
1.5	60,038,782	0	0.00000	1.00000	100.00
2.5	56,196,682	0	0.00000	1.00000	100.00
3.5	56,196,682	0	0.00000	1.00000	100.00
4.5	56,196,682	0	0.00000	1.00000	100.00
5.5	46,865,357	0	0.00000	1.00000	100.00
6.5	38,725,887	0	0.00000	1.00000	100.00
7.5	23,655,685	0	0.00000	1.00000	100.00
8.5	23,617,789	0	0.00000	1.00000	100.00
9.5	13,852,946	0	0.00000	1.00000	100.00
10.5	13,852,946	0	0.00000	1.00000	100.00
11.5	5,687,951	0	0.00000	1.00000	100.00
12.5	4,570,209	0	0.00000	1.00000	100.00
13.5	4,532,395	0	0.00000	1.00000	100.00
14.5	4,532,395	0	0.00000	1.00000	100.00
15.5	4,532,395	0	0.00000	1.00000	100.00
16.5	3,022,479	0	0.00000	1.00000	100.00
17.5	1,363,588	0	0.00000	1.00000	100.00
18.5	1,314,867	0	0.00000	1.00000	100.00
19.5	1,314,867	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 52103 - Transformer, Power - > 100Mva

Placement Band - 1939 - 2019   Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52103 - Transformer, Power - > 100Mva

Placement Band - 1939 - 2019   Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	165,270,567	0	0.00000	1.00000	100.00
0.5	165,270,567	0	0.00000	1.00000	100.00
1.5	158,195,062	0	0.00000	1.00000	100.00
2.5	152,021,091	0	0.00000	1.00000	100.00
3.5	130,981,073	0	0.00000	1.00000	100.00
4.5	105,029,636	0	0.00000	1.00000	100.00
5.5	85,571,001	0	0.00000	1.00000	100.00
6.5	69,003,630	0	0.00000	1.00000	100.00
7.5	69,854,231	0	0.00000	1.00000	100.00
8.5	69,990,007	0	0.00000	1.00000	100.00
9.5	69,663,682	0	0.00000	1.00000	100.00
10.5	55,060,449	0	0.00000	1.00000	100.00
11.5	44,397,307	0	0.00000	1.00000	100.00
12.5	33,876,610	0	0.00000	1.00000	100.00
13.5	31,968,084	0	0.00000	1.00000	100.00
14.5	29,979,615	0	0.00000	1.00000	100.00
15.5	29,977,475	0	0.00000	1.00000	100.00
16.5	23,808,457	0	0.00000	1.00000	100.00
17.5	22,181,180	0	0.00000	1.00000	100.00
18.5	19,839,926	986,180	0.04971	0.95029	100.00
19.5	18,853,746	0	0.00000	1.00000	95.03
20.5	18,853,746	0	0.00000	1.00000	95.03
21.5	18,853,746	0	0.00000	1.00000	95.03
22.5	18,853,746	0	0.00000	1.00000	95.03
23.5	18,853,746	0	0.00000	1.00000	95.03
24.5	13,558,955	0	0.00000	1.00000	95.03
25.5	12,235,795	0	0.00000	1.00000	95.03
26.5	9,628,910	0	0.00000	1.00000	95.03

BC Hydro Power Authority

Account 52103 - Transformer, Power - > 100Mva

Placement Band - 1939 - 2019 Experience Band - 2014 - 2020

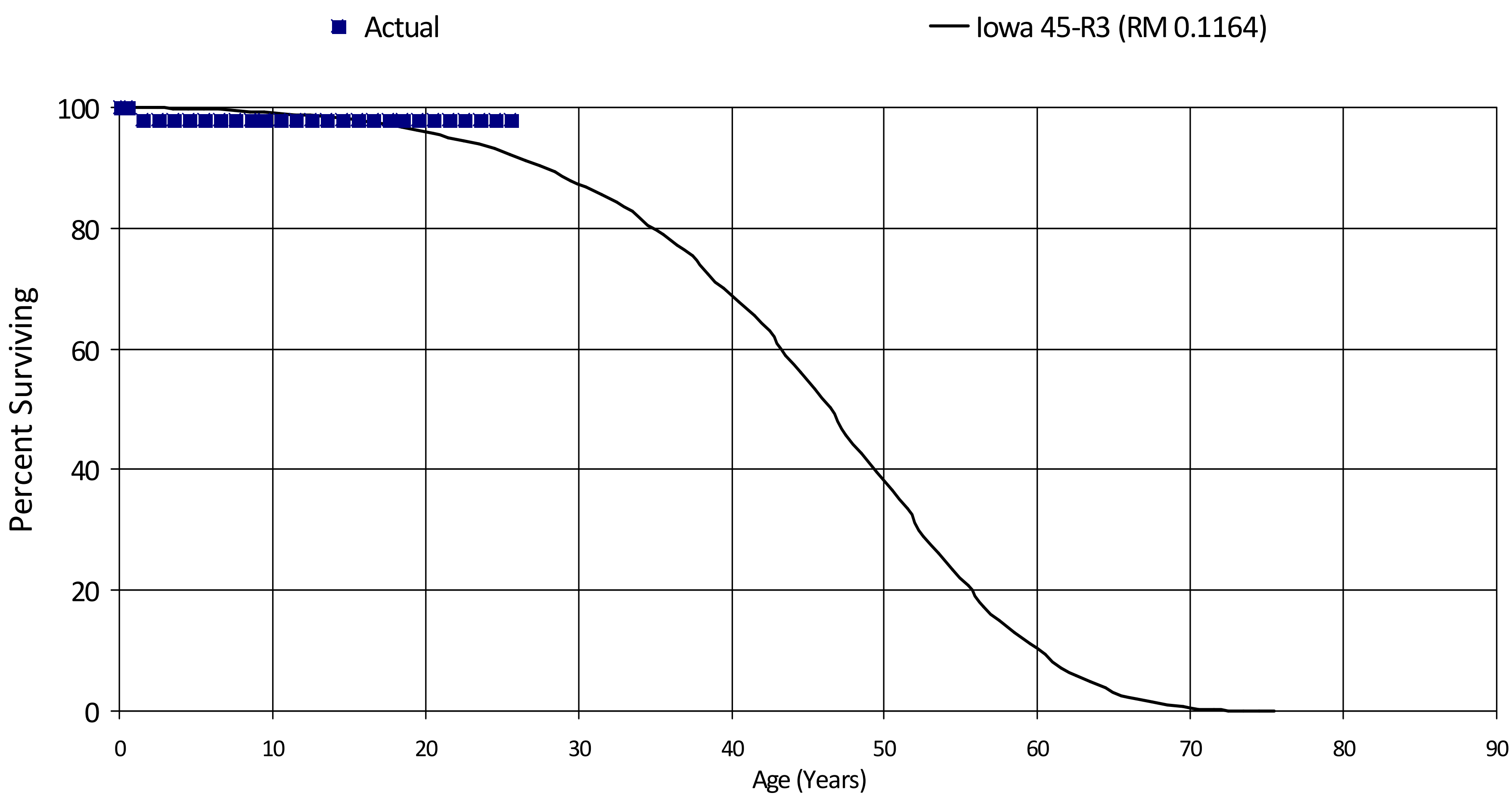
27.5	9,628,910	0	0.00000	1.00000	95.03
28.5	9,628,910	0	0.00000	1.00000	95.03
29.5	9,628,910	0	0.00000	1.00000	95.03
30.5	9,628,910	0	0.00000	1.00000	95.03
31.5	9,628,910	0	0.00000	1.00000	95.03
32.5	9,628,910	0	0.00000	1.00000	95.03
33.5	9,628,910	0	0.00000	1.00000	95.03
34.5	9,628,910	0	0.00000	1.00000	95.03
35.5	8,579,277	0	0.00000	1.00000	95.03
36.5	8,579,277	245,625	0.02863	0.97137	95.03
37.5	8,333,652	0	0.00000	1.00000	92.31
38.5	8,213,522	0	0.00000	1.00000	92.31
39.5	7,651,796	0	0.00000	1.00000	92.31
40.5	6,249,500	0	0.00000	1.00000	92.31
41.5	6,099,095	0	0.00000	1.00000	92.31
42.5	6,099,095	0	0.00000	1.00000	92.31
43.5	6,099,095	0	0.00000	1.00000	92.31
44.5	6,099,095	0	0.00000	1.00000	92.31
	Totals:	1,231,805			

BC Hydro Power Authority

Account 52104 - Transformer, Power - < 100Mva

Placement Band - 1927 - 2019   Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52104 - Transformer, Power - < 100Mva

Placement Band - 1927 - 2019 Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

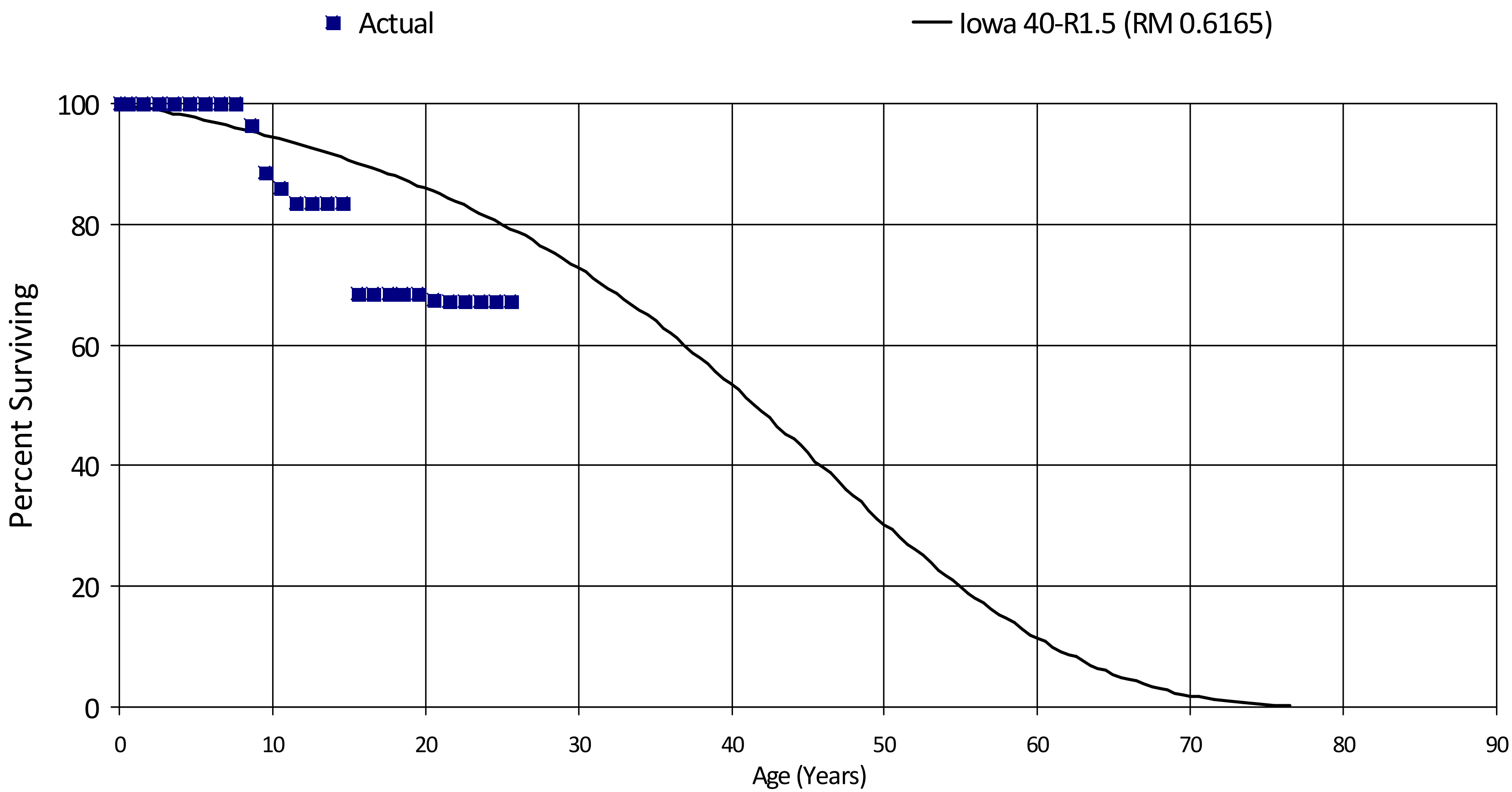
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	184,046,333	0	0.00000	1.00000	100.00
0.5	184,046,333	3,561,927	0.01935	0.98065	100.00
1.5	175,428,559	0	0.00000	1.00000	98.06
2.5	168,577,813	0	0.00000	1.00000	98.06
3.5	155,574,758	0	0.00000	1.00000	98.06
4.5	135,074,803	0	0.00000	1.00000	98.06
5.5	109,383,208	0	0.00000	1.00000	98.06
6.5	99,329,933	0	0.00000	1.00000	98.06
7.5	90,872,153	0	0.00000	1.00000	98.06
8.5	69,631,093	0	0.00000	1.00000	98.06
9.5	66,605,303	0	0.00000	1.00000	98.06
10.5	63,561,095	0	0.00000	1.00000	98.06
11.5	49,982,166	0	0.00000	1.00000	98.06
12.5	38,734,718	0	0.00000	1.00000	98.06
13.5	28,289,978	10,758	0.00038	0.99962	98.06
14.5	20,123,892	0	0.00000	1.00000	98.02
15.5	19,270,703	0	0.00000	1.00000	98.02
16.5	18,685,656	0	0.00000	1.00000	98.02
17.5	14,982,462	0	0.00000	1.00000	98.02
18.5	13,415,231	0	0.00000	1.00000	98.02
19.5	11,850,241	0	0.00000	1.00000	98.02
20.5	10,417,282	2	0.00000	1.00000	98.02
21.5	8,747,519	0	0.00000	1.00000	98.02
22.5	7,709,544	0	0.00000	1.00000	98.02
23.5	7,492,659	0	0.00000	1.00000	98.02
24.5	7,280,419	0	0.00000	1.00000	98.02
25.5	6,769,491	0	0.00000	1.00000	98.02
	Totals:	3,572,687			

BC Hydro Power Authority

Account 52105 - Transformer, Station Service

Placement Band - 1927 - 2019 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52105 - Transformer, Station Service

Placement Band - 1927 - 2019   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

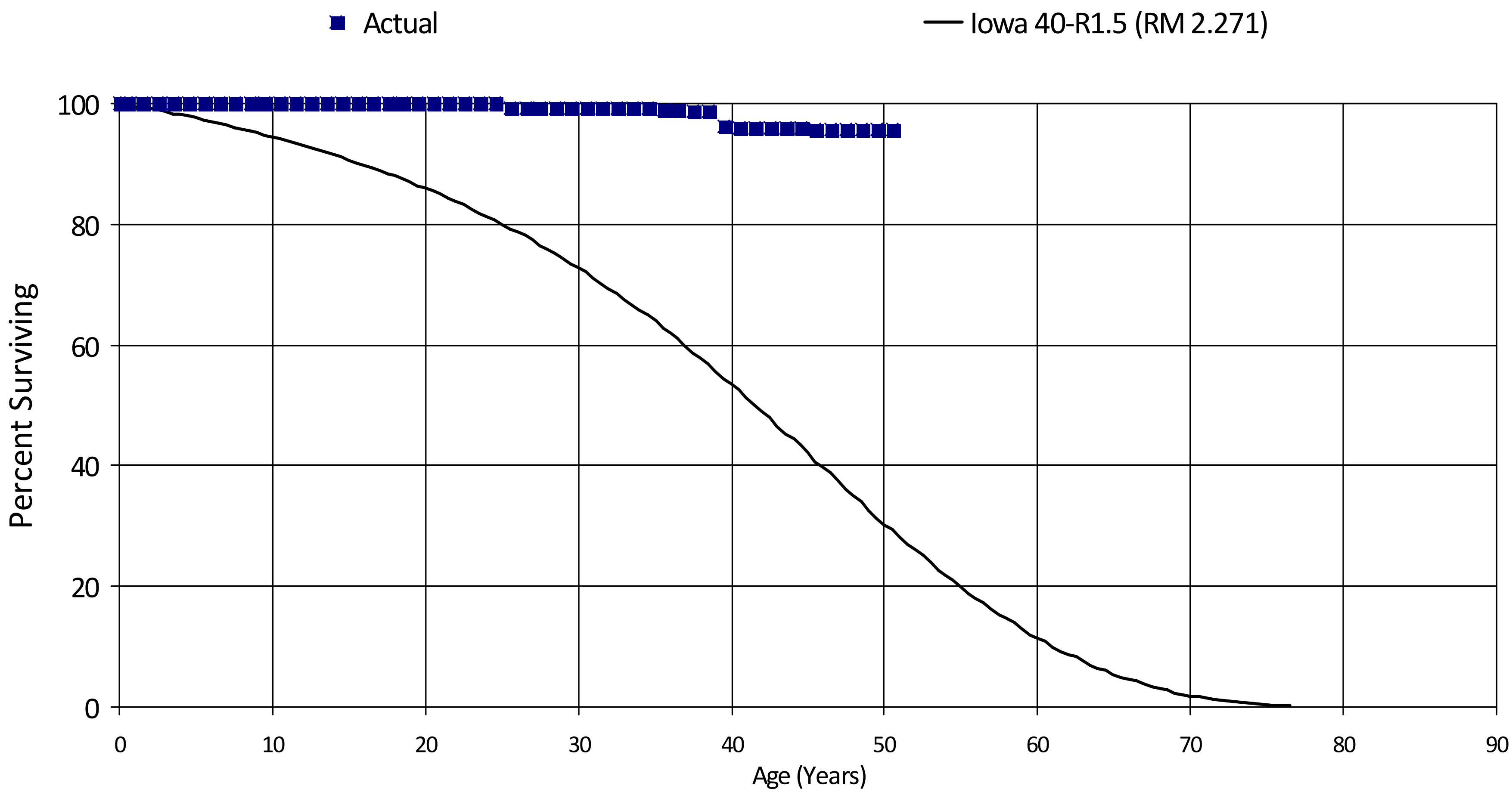
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	58,646,377	0	0.00000	1.00000	100.00
0.5	58,646,377	0	0.00000	1.00000	100.00
1.5	45,417,944	0	0.00000	1.00000	100.00
2.5	44,780,333	28,195	0.00063	0.99937	100.00
3.5	40,630,620	0	0.00000	1.00000	99.94
4.5	31,712,245	0	0.00000	1.00000	99.94
5.5	24,672,868	1	0.00000	1.00000	99.94
6.5	22,979,611	0	0.00000	1.00000	99.94
7.5	22,289,081	800,135	0.03590	0.96410	99.94
8.5	17,234,690	1,398,353	0.08114	0.91886	96.35
9.5	13,892,037	396,586	0.02855	0.97145	88.53
10.5	13,301,710	396,576	0.02981	0.97019	86.00
11.5	12,864,099	0	0.00000	1.00000	83.44
12.5	9,816,656	0	0.00000	1.00000	83.44
13.5	9,592,308	0	0.00000	1.00000	83.44
14.5	9,258,854	1,644,744	0.17764	0.82236	83.44
15.5	7,450,005	0	0.00000	1.00000	68.62
16.5	2,360,439	0	0.00000	1.00000	68.62
17.5	2,313,827	0	0.00000	1.00000	68.62
18.5	2,091,273	0	0.00000	1.00000	68.62
19.5	2,044,403	35,505	0.01737	0.98263	68.62
20.5	1,533,825	1,812	0.00118	0.99882	67.43
21.5	1,489,760	0	0.00000	1.00000	67.35
22.5	996,070	0	0.00000	1.00000	67.35
23.5	987,290	0	0.00000	1.00000	67.35
24.5	773,341	0	0.00000	1.00000	67.35
25.5	755,961	277,028	0.36646	0.63354	67.35
	Totals:	4,978,935			

BC Hydro Power Authority

Account 52106 - Transformer, Power, Comp Pool

Placement Band - 1931 - 2015 Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52106 - Transformer, Power, Comp Pool

Placement Band - 1931 - 2015   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	62,685,523	0	0.00000	1.00000	100.00
0.5	62,685,523	0	0.00000	1.00000	100.00
1.5	62,685,523	0	0.00000	1.00000	100.00
2.5	62,685,523	0	0.00000	1.00000	100.00
3.5	62,685,523	11,423	0.00018	0.99982	100.00
4.5	62,674,100	22,846	0.00036	0.99964	99.98
5.5	61,844,217	0	0.00000	1.00000	99.94
6.5	60,727,425	0	0.00000	1.00000	99.94
7.5	60,445,642	0	0.00000	1.00000	99.94
8.5	53,500,631	0	0.00000	1.00000	99.94
9.5	46,044,219	0	0.00000	1.00000	99.94
10.5	45,466,553	0	0.00000	1.00000	99.94
11.5	42,051,903	0	0.00000	1.00000	99.94
12.5	41,233,154	0	0.00000	1.00000	99.94
13.5	40,819,210	0	0.00000	1.00000	99.94
14.5	39,321,801	2,535	0.00006	0.99994	99.94
15.5	39,306,425	0	0.00000	1.00000	99.93
16.5	39,197,287	0	0.00000	1.00000	99.93
17.5	39,193,896	0	0.00000	1.00000	99.93
18.5	39,193,896	0	0.00000	1.00000	99.93
19.5	39,193,896	0	0.00000	1.00000	99.93
20.5	39,193,896	13,251	0.00034	0.99966	99.93
21.5	39,180,645	0	0.00000	1.00000	99.90
22.5	39,136,994	0	0.00000	1.00000	99.90
23.5	39,109,810	0	0.00000	1.00000	99.90
24.5	39,103,430	261,886	0.00670	0.99330	99.90
25.5	38,822,336	0	0.00000	1.00000	99.23
26.5	38,822,336	0	0.00000	1.00000	99.23

BC Hydro Power Authority

Account 52106 - Transformer, Power, Comp Pool

Placement Band - 1931 - 2015   Experience Band - 2011 - 2020

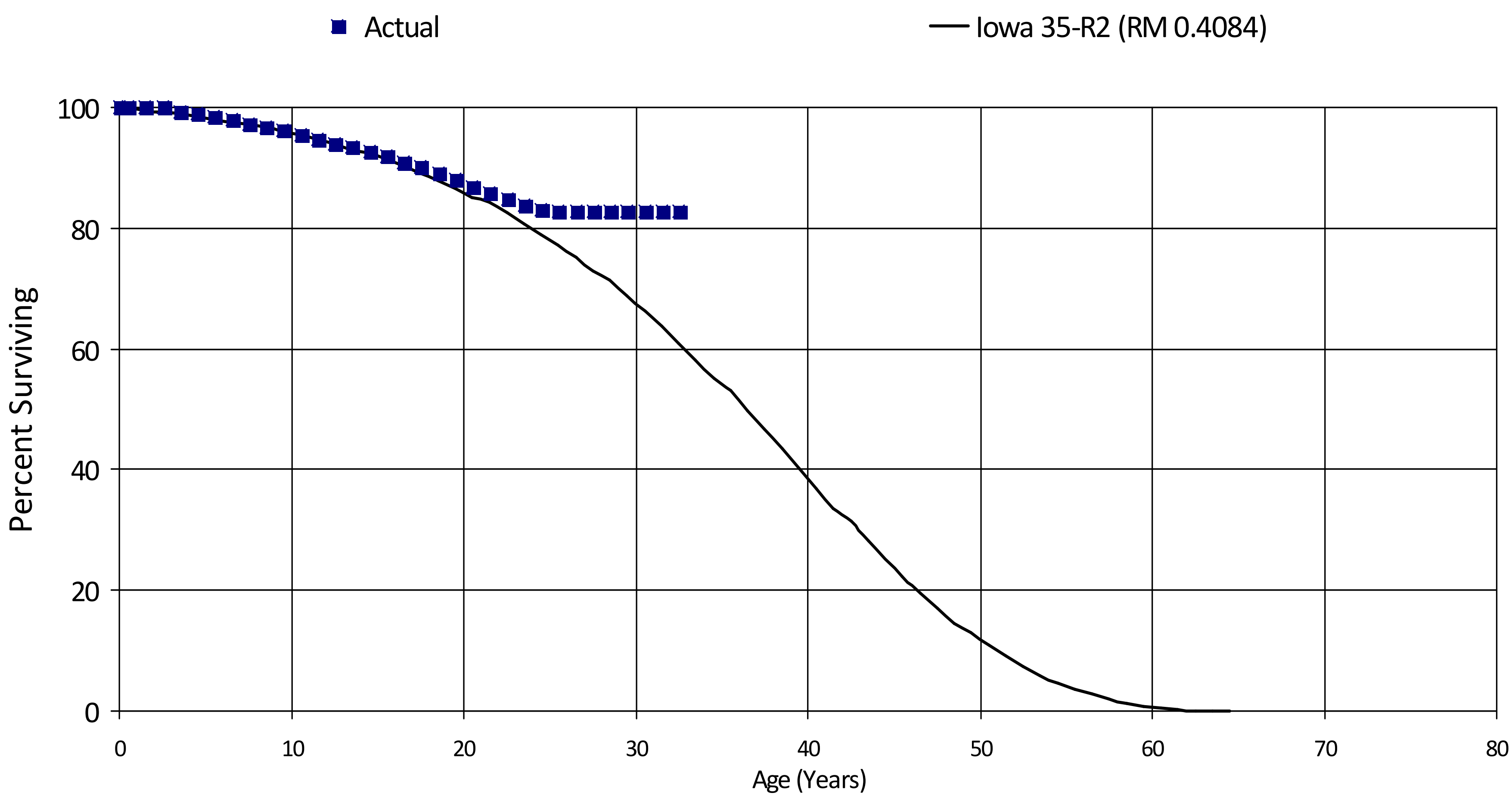
27.5	38,822,336	3,163	0.00008	0.99992	99.23
28.5	38,222,729	23,368	0.00061	0.99939	99.22
29.5	36,277,490	0	0.00000	1.00000	99.16
30.5	31,657,613	0	0.00000	1.00000	99.16
31.5	24,278,592	0	0.00000	1.00000	99.16
32.5	22,558,407	389	0.00002	0.99998	99.16
33.5	21,797,327	0	0.00000	1.00000	99.16
34.5	21,481,910	29,941	0.00139	0.99861	99.16
35.5	20,522,894	0	0.00000	1.00000	99.02
36.5	20,088,079	36,429	0.00181	0.99819	99.02
37.5	19,769,143	158	0.00001	0.99999	98.84
38.5	18,535,521	501,546	0.02706	0.97294	98.84
39.5	16,967,190	33,528	0.00198	0.99802	96.17
40.5	12,321,284	884	0.00007	0.99993	95.98
41.5	8,335,287	331	0.00004	0.99996	95.97
42.5	6,575,214	0	0.00000	1.00000	95.97
43.5	1,767,324	0	0.00000	1.00000	95.97
44.5	1,688,696	3,439	0.00204	0.99796	95.97
45.5	1,091,073	0	0.00000	1.00000	95.77
46.5	996,653	0	0.00000	1.00000	95.77
47.5	970,326	0	0.00000	1.00000	95.77
48.5	780,581	0	0.00000	1.00000	95.77
49.5	780,581	0	0.00000	1.00000	95.77
50.5	780,571	0	0.00000	1.00000	95.77
	Totals:	945,117			

BC Hydro Power Authority

Account 52201 - Transformer, Distribution

Placement Band - 1976 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52201 - Transformer, Distribution

Placement Band - 1976 - 2020 Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,157,713,120	0	0.00000	1.00000	100.00
0.5	1,143,856,111	0	0.00000	1.00000	100.00
1.5	1,063,345,688	1,300,171	0.00122	0.99878	100.00
2.5	970,731,448	5,404,095	0.00557	0.99443	99.88
3.5	887,856,533	3,306,162	0.00372	0.99628	99.32
4.5	822,074,164	3,697,131	0.00450	0.99550	98.95
5.5	742,192,201	4,159,866	0.00560	0.99440	98.50
6.5	681,567,329	4,364,042	0.00640	0.99360	97.95
7.5	638,814,011	3,337,037	0.00522	0.99478	97.32
8.5	571,505,268	4,120,795	0.00721	0.99279	96.81
9.5	500,810,164	4,100,447	0.00819	0.99181	96.11
10.5	462,431,651	3,208,479	0.00694	0.99306	95.32
11.5	410,448,192	2,864,621	0.00698	0.99302	94.66
12.5	342,465,481	2,430,841	0.00710	0.99290	94.00
13.5	300,741,707	2,401,173	0.00798	0.99202	93.33
14.5	267,727,567	2,151,932	0.00804	0.99196	92.59
15.5	236,116,550	2,307,587	0.00977	0.99023	91.85
16.5	210,142,948	2,133,755	0.01015	0.98985	90.95
17.5	182,757,001	2,173,359	0.01189	0.98811	90.03
18.5	167,915,713	1,814,757	0.01081	0.98919	88.96
19.5	150,867,663	1,884,309	0.01249	0.98751	88.00
20.5	136,763,557	1,816,126	0.01328	0.98672	86.90
21.5	121,567,752	1,299,240	0.01069	0.98931	85.75
22.5	103,014,901	1,190,031	0.01155	0.98845	84.83
23.5	90,319,645	856,632	0.00948	0.99052	83.85
24.5	73,790,767	268,559	0.00364	0.99636	83.06
25.5	59,251,579	0	0.00000	1.00000	82.76
26.5	46,586,714	0	0.00000	1.00000	82.76

BC Hydro Power Authority

Account 52201 - Transformer, Distribution

Placement Band - 1976 - 2020 Experience Band - 2013 - 2020

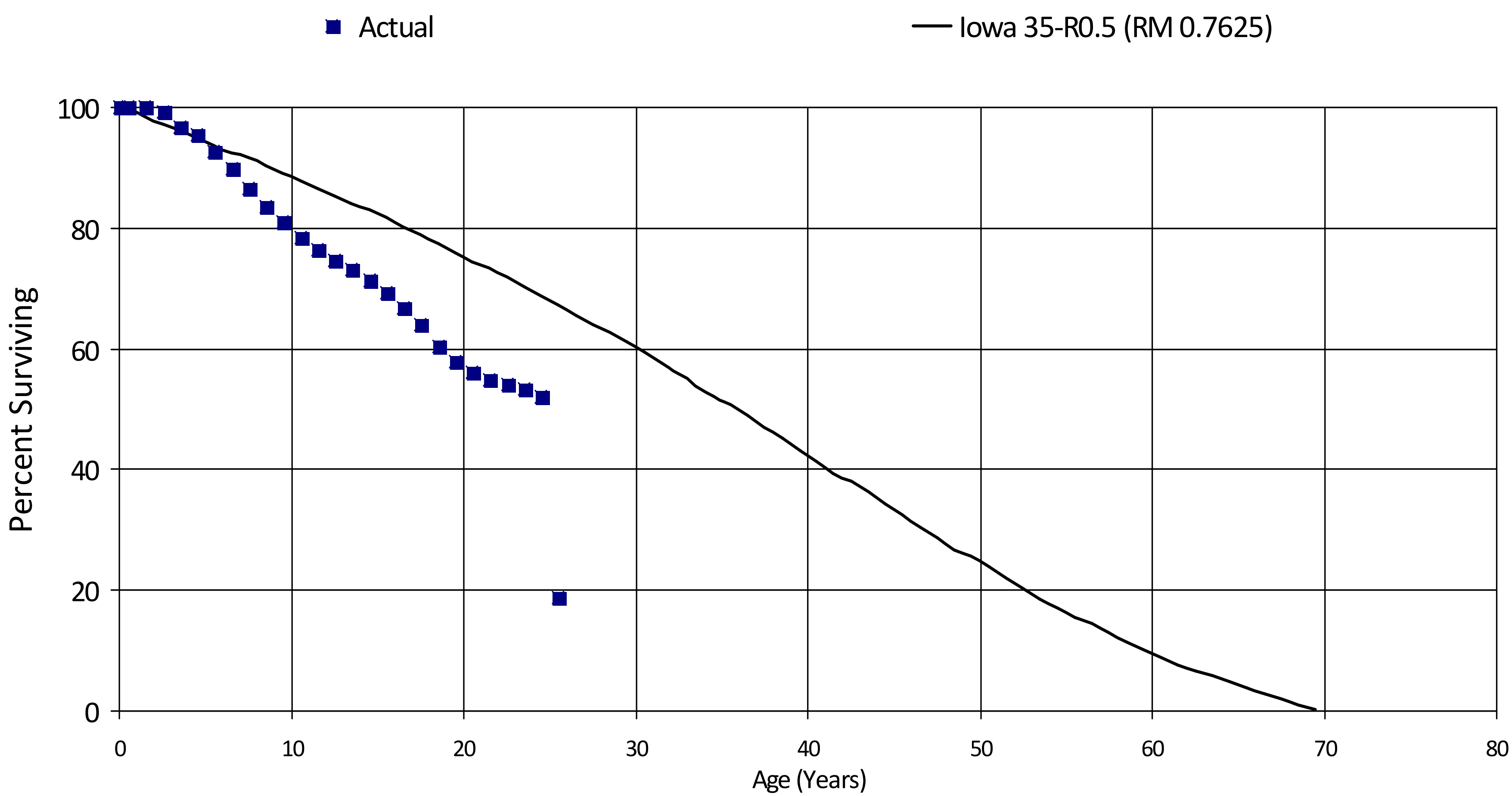
27.5	36,964,033	0	0.00000	1.00000	82.76
28.5	27,716,044	0	0.00000	1.00000	82.76
29.5	21,644,182	0	0.00000	1.00000	82.76
30.5	17,389,890	0	0.00000	1.00000	82.76
31.5	16,099,449	0	0.00000	1.00000	82.76
32.5	12,896,607	0	0.00000	1.00000	82.76
	Totals:	62,591,147			

BC Hydro Power Authority

Account 52202 - Distribution, Cutouts

Placement Band - 1987 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52202 - Distribution, Cutouts

Placement Band - 1987 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

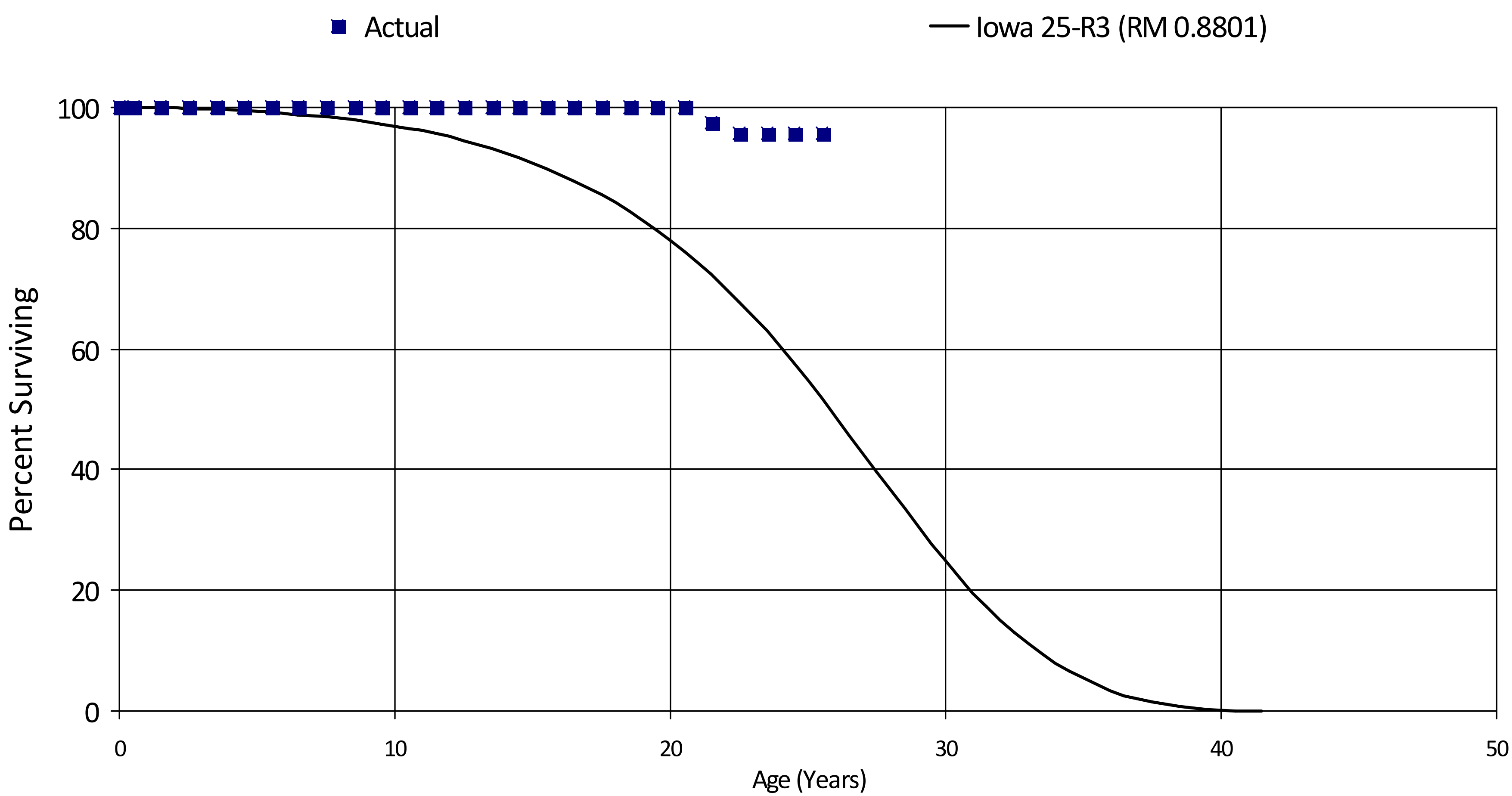
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	74,862,055	0	0.00000	1.00000	100.00
0.5	73,637,476	0	0.00000	1.00000	100.00
1.5	68,990,049	585,241	0.00848	0.99152	100.00
2.5	62,008,083	1,460,989	0.02356	0.97644	99.15
3.5	55,349,819	850,817	0.01537	0.98463	96.81
4.5	49,719,199	1,365,710	0.02747	0.97253	95.32
5.5	44,182,336	1,402,008	0.03173	0.96827	92.70
6.5	38,674,956	1,388,936	0.03591	0.96409	89.76
7.5	32,977,221	1,194,650	0.03623	0.96377	86.54
8.5	25,610,301	751,770	0.02935	0.97065	83.40
9.5	22,616,428	679,582	0.03005	0.96995	80.95
10.5	21,395,154	587,239	0.02745	0.97255	78.52
11.5	18,355,758	406,657	0.02215	0.97785	76.36
12.5	15,011,330	317,189	0.02113	0.97887	74.67
13.5	13,079,293	305,751	0.02338	0.97662	73.09
14.5	11,617,153	349,617	0.03009	0.96991	71.38
15.5	10,164,911	374,950	0.03689	0.96311	69.23
16.5	8,954,352	367,680	0.04106	0.95894	66.68
17.5	6,687,022	364,864	0.05456	0.94544	63.94
18.5	6,322,157	276,111	0.04367	0.95633	60.45
19.5	5,495,397	164,666	0.02996	0.97004	57.81
20.5	4,897,017	105,186	0.02148	0.97852	56.08
21.5	4,374,873	66,844	0.01528	0.98472	54.88
22.5	3,818,745	59,460	0.01557	0.98443	54.04
23.5	3,374,758	76,042	0.02253	0.97747	53.20
24.5	2,870,463	1,834,368	0.63905	0.36095	52.00
25.5	887,459	395,642	0.44581	0.55419	18.77
	Totals:	15,731,969			

BC Hydro Power Authority

Account 52301 - Reactor, Oil

Placement Band - 1966 - 2017   Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52301 - Reactor, Oil

Placement Band - 1966 - 2017   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

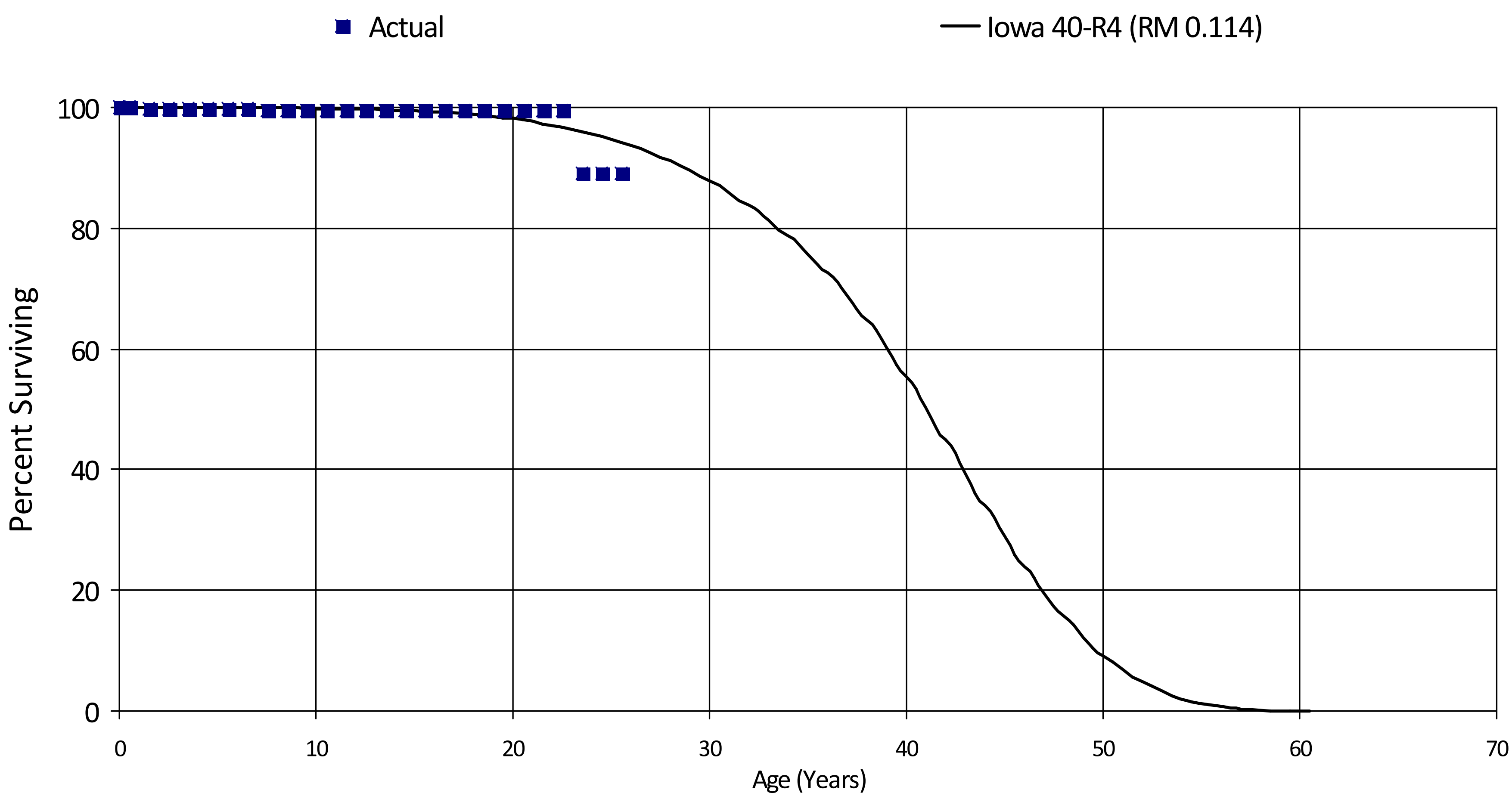
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	38,579,115	0	0.00000	1.00000	100.00
0.5	38,579,115	0	0.00000	1.00000	100.00
1.5	38,579,115	0	0.00000	1.00000	100.00
2.5	38,579,115	0	0.00000	1.00000	100.00
3.5	30,840,724	0	0.00000	1.00000	100.00
4.5	30,840,724	0	0.00000	1.00000	100.00
5.5	30,840,724	0	0.00000	1.00000	100.00
6.5	19,225,234	0	0.00000	1.00000	100.00
7.5	17,862,929	0	0.00000	1.00000	100.00
8.5	17,862,929	0	0.00000	1.00000	100.00
9.5	17,862,929	0	0.00000	1.00000	100.00
10.5	13,038,080	0	0.00000	1.00000	100.00
11.5	13,038,080	0	0.00000	1.00000	100.00
12.5	9,434,685	0	0.00000	1.00000	100.00
13.5	9,434,685	0	0.00000	1.00000	100.00
14.5	9,434,685	0	0.00000	1.00000	100.00
15.5	7,583,681	0	0.00000	1.00000	100.00
16.5	4,779,991	0	0.00000	1.00000	100.00
17.5	2,662,600	0	0.00000	1.00000	100.00
18.5	2,654,138	0	0.00000	1.00000	100.00
19.5	2,654,138	0	0.00000	1.00000	100.00
20.5	2,654,138	70,336	0.02650	0.97350	100.00
21.5	1,998,082	36,649	0.01834	0.98166	97.35
22.5	1,696,178	0	0.00000	1.00000	95.56
23.5	1,696,178	0	0.00000	1.00000	95.56
24.5	1,696,178	0	0.00000	1.00000	95.56
25.5	508,594	0	0.00000	1.00000	95.56
	Totals:	106,985			

BC Hydro Power Authority

Account 52302 - Reactor, Dry Type

Placement Band - 1965 - 2019 Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52302 - Reactor, Dry Type

Placement Band - 1965 - 2019   Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

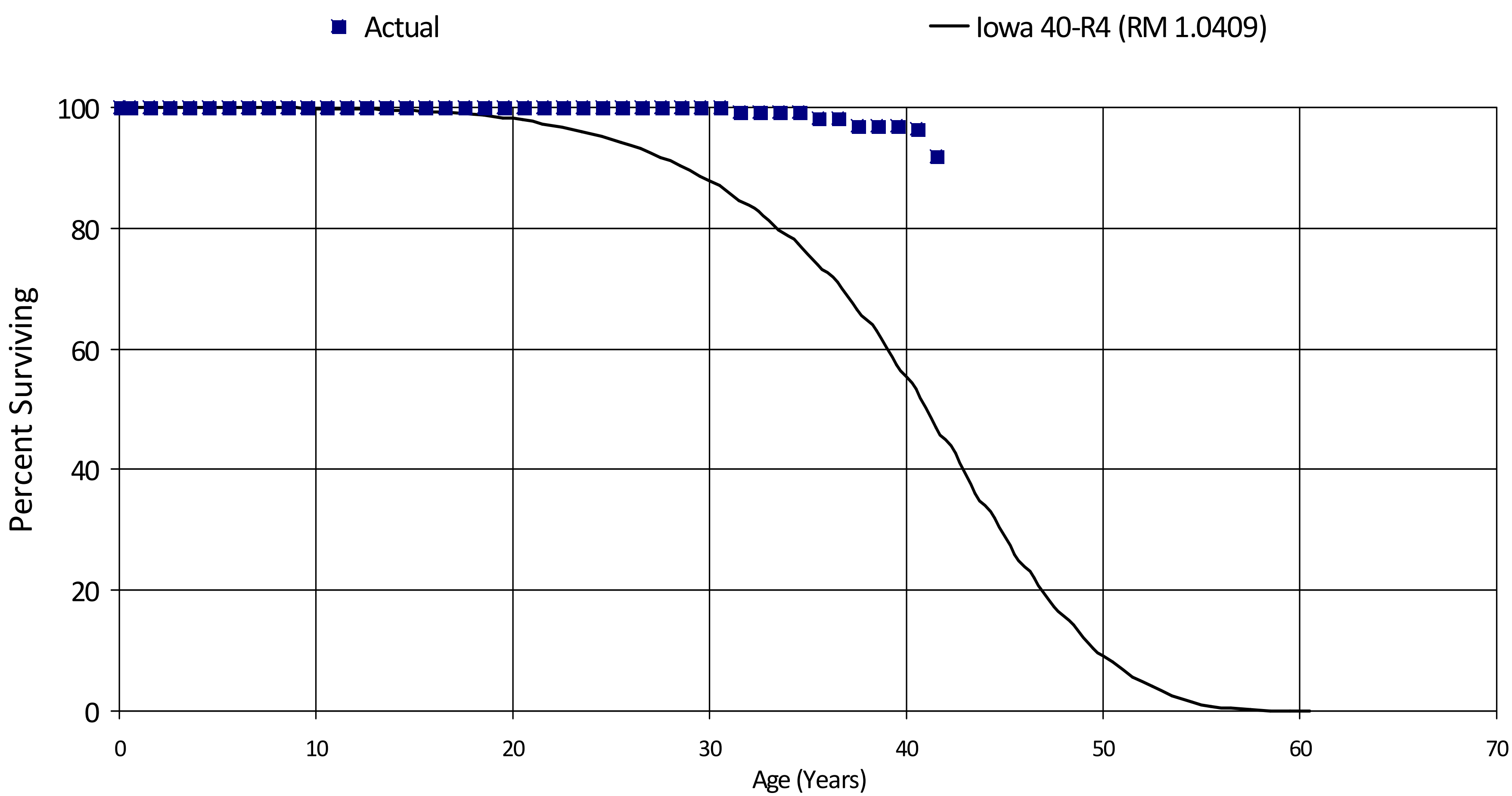
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	57,466,341	0	0.00000	1.00000	100.00
0.5	57,466,341	106,577	0.00185	0.99815	100.00
1.5	55,200,232	0	0.00000	1.00000	99.82
2.5	50,402,775	46,380	0.00092	0.99908	99.82
3.5	48,448,755	0	0.00000	1.00000	99.73
4.5	41,559,414	0	0.00000	1.00000	99.73
5.5	33,791,110	0	0.00000	1.00000	99.73
6.5	29,881,527	36,672	0.00123	0.99877	99.73
7.5	28,384,615	0	0.00000	1.00000	99.61
8.5	24,823,024	0	0.00000	1.00000	99.61
9.5	23,672,608	0	0.00000	1.00000	99.61
10.5	21,903,760	0	0.00000	1.00000	99.61
11.5	18,233,817	0	0.00000	1.00000	99.61
12.5	15,732,811	0	0.00000	1.00000	99.61
13.5	12,274,645	0	0.00000	1.00000	99.61
14.5	10,243,511	0	0.00000	1.00000	99.61
15.5	10,042,429	0	0.00000	1.00000	99.61
16.5	8,043,524	0	0.00000	1.00000	99.61
17.5	7,437,207	0	0.00000	1.00000	99.61
18.5	6,529,208	0	0.00000	1.00000	99.61
19.5	6,222,564	0	0.00000	1.00000	99.61
20.5	6,222,564	0	0.00000	1.00000	99.61
21.5	5,987,338	0	0.00000	1.00000	99.61
22.5	5,537,236	583,976	0.10546	0.89454	99.61
23.5	4,612,602	0	0.00000	1.00000	89.11
24.5	3,935,360	0	0.00000	1.00000	89.11
25.5	2,633,565	0	0.00000	1.00000	89.11
	Totals:	773,605			

BC Hydro Power Authority

Account 52303 - Reactor, Composite Pool

Placement Band - 1958 - 2016   Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52303 - Reactor, Composite Pool

Placement Band - 1958 - 2016 Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	7,642,170	0	0.00000	1.00000	100.00
0.5	7,642,170	0	0.00000	1.00000	100.00
1.5	7,642,170	0	0.00000	1.00000	100.00
2.5	7,642,170	0	0.00000	1.00000	100.00
3.5	7,642,170	0	0.00000	1.00000	100.00
4.5	7,590,791	0	0.00000	1.00000	100.00
5.5	7,590,791	0	0.00000	1.00000	100.00
6.5	7,590,791	0	0.00000	1.00000	100.00
7.5	7,590,791	0	0.00000	1.00000	100.00
8.5	7,238,626	0	0.00000	1.00000	100.00
9.5	7,238,626	0	0.00000	1.00000	100.00
10.5	7,219,810	0	0.00000	1.00000	100.00
11.5	7,169,663	0	0.00000	1.00000	100.00
12.5	7,169,663	0	0.00000	1.00000	100.00
13.5	7,131,306	0	0.00000	1.00000	100.00
14.5	7,102,733	0	0.00000	1.00000	100.00
15.5	7,102,693	0	0.00000	1.00000	100.00
16.5	7,102,693	0	0.00000	1.00000	100.00
17.5	7,098,295	0	0.00000	1.00000	100.00
18.5	7,098,295	0	0.00000	1.00000	100.00
19.5	7,098,295	0	0.00000	1.00000	100.00
20.5	7,098,295	0	0.00000	1.00000	100.00
21.5	7,098,295	0	0.00000	1.00000	100.00
22.5	7,098,295	0	0.00000	1.00000	100.00
23.5	6,939,662	0	0.00000	1.00000	100.00
24.5	6,586,358	0	0.00000	1.00000	100.00
25.5	6,586,358	0	0.00000	1.00000	100.00
26.5	6,586,358	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 52303 - Reactor, Composite Pool

Placement Band - 1958 - 2016 Experience Band - 2014 - 2020

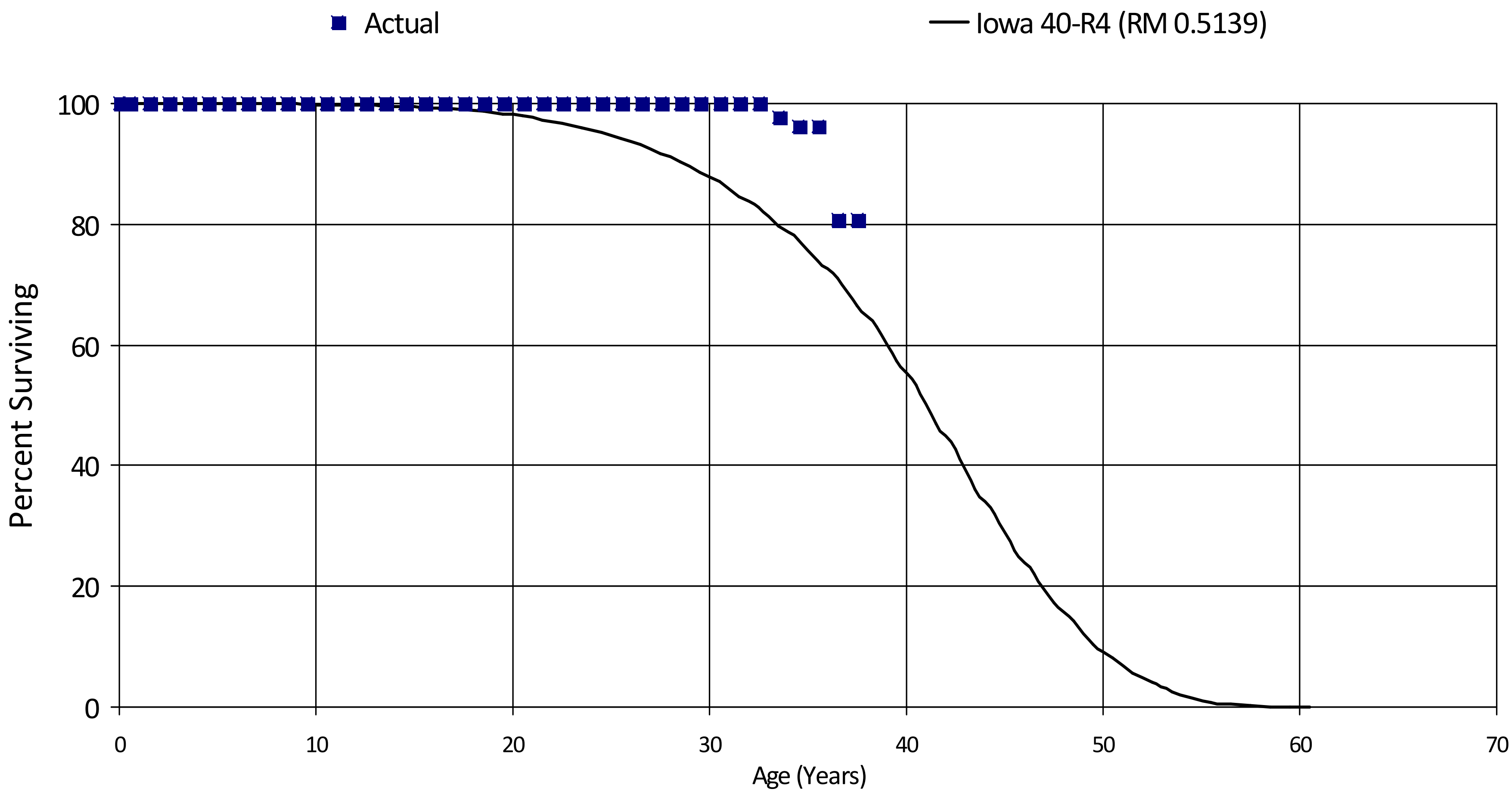
27.5	6,564,795	0	0.00000	1.00000	100.00
28.5	6,564,795	0	0.00000	1.00000	100.00
29.5	6,430,352	0	0.00000	1.00000	100.00
30.5	5,693,440	38,697	0.00680	0.99320	100.00
31.5	5,336,578	0	0.00000	1.00000	99.32
32.5	5,243,558	3,674	0.00070	0.99930	99.32
33.5	5,176,733	2,446	0.00047	0.99953	99.25
34.5	2,687,190	24,291	0.00904	0.99096	99.20
35.5	1,683,736	0	0.00000	1.00000	98.30
36.5	1,683,736	24,017	0.01426	0.98574	98.30
37.5	1,460,951	0	0.00000	1.00000	96.90
38.5	1,381,486	0	0.00000	1.00000	96.90
39.5	1,102,854	4,280	0.00388	0.99612	96.90
40.5	558,364	26,938	0.04824	0.95176	96.52
41.5	95,153	30	0.00032	0.99968	91.86
	Totals:	124,373			

BC Hydro Power Authority

Account 52401 - Oil, 69 Kv & Above

Placement Band - 1966 - 2016   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52401 - Oil, 69 Kv & Above

Placement Band - 1966 - 2016   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	27,466,929	0	0.00000	1.00000	100.00
0.5	27,466,929	0	0.00000	1.00000	100.00
1.5	27,466,929	0	0.00000	1.00000	100.00
2.5	27,466,929	0	0.00000	1.00000	100.00
3.5	27,466,929	0	0.00000	1.00000	100.00
4.5	19,578,095	0	0.00000	1.00000	100.00
5.5	19,351,281	0	0.00000	1.00000	100.00
6.5	19,351,281	0	0.00000	1.00000	100.00
7.5	19,351,281	0	0.00000	1.00000	100.00
8.5	19,351,281	0	0.00000	1.00000	100.00
9.5	1,246,392	0	0.00000	1.00000	100.00
10.5	1,140,984	0	0.00000	1.00000	100.00
11.5	1,140,984	0	0.00000	1.00000	100.00
12.5	1,140,984	0	0.00000	1.00000	100.00
13.5	1,122,045	0	0.00000	1.00000	100.00
14.5	1,122,045	0	0.00000	1.00000	100.00
15.5	1,107,593	0	0.00000	1.00000	100.00
16.5	1,107,593	0	0.00000	1.00000	100.00
17.5	1,107,593	0	0.00000	1.00000	100.00
18.5	1,107,593	0	0.00000	1.00000	100.00
19.5	1,107,593	0	0.00000	1.00000	100.00
20.5	1,107,593	0	0.00000	1.00000	100.00
21.5	1,107,593	0	0.00000	1.00000	100.00
22.5	1,058,143	0	0.00000	1.00000	100.00
23.5	988,586	0	0.00000	1.00000	100.00
24.5	988,586	0	0.00000	1.00000	100.00
25.5	959,140	0	0.00000	1.00000	100.00
26.5	928,810	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 52401 - Oil, 69 Kv & Above

Placement Band - 1966 - 2016 Experience Band - 2013 - 2020

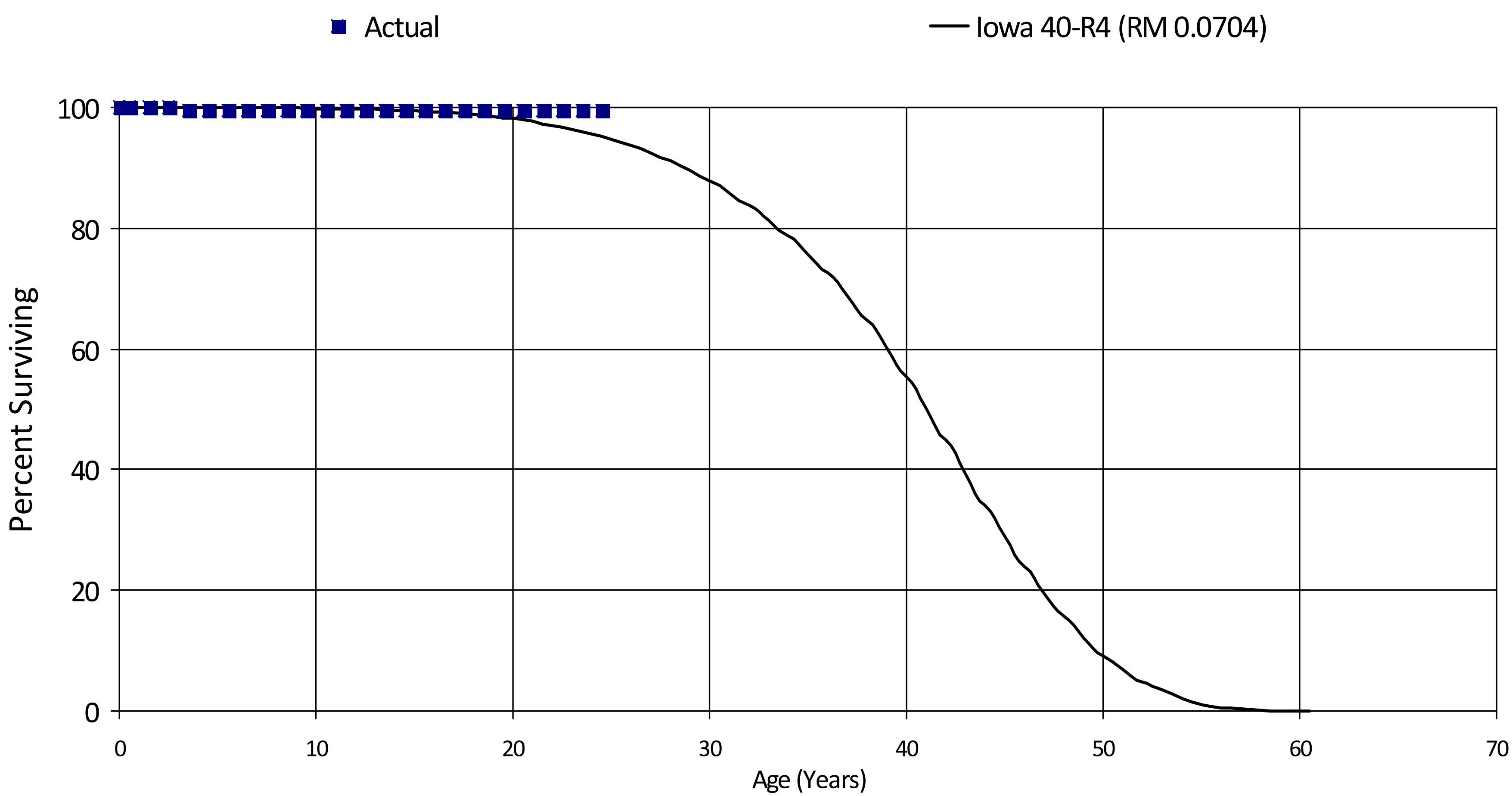
27.5	928,810	0	0.00000	1.00000	100.00
28.5	921,444	0	0.00000	1.00000	100.00
29.5	921,444	0	0.00000	1.00000	100.00
30.5	919,899	0	0.00000	1.00000	100.00
31.5	919,899	0	0.00000	1.00000	100.00
32.5	868,319	18,790	0.02164	0.97836	100.00
33.5	509,966	8,486	0.01664	0.98336	97.84
34.5	501,480	0	0.00000	1.00000	96.21
35.5	394,949	63,568	0.16095	0.83905	96.21
36.5	331,381	0	0.00000	1.00000	80.73
37.5	291,405	20,063	0.06885	0.93115	80.73
	Totals:	110,907			

BC Hydro Power Authority

Account 52402 - Gas, Sf6, 69 Kv & Above

Placement Band - 1967 - 2019 Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52402 - Gas, Sf6, 69 Kv & Above

Placement Band - 1967 - 2019   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

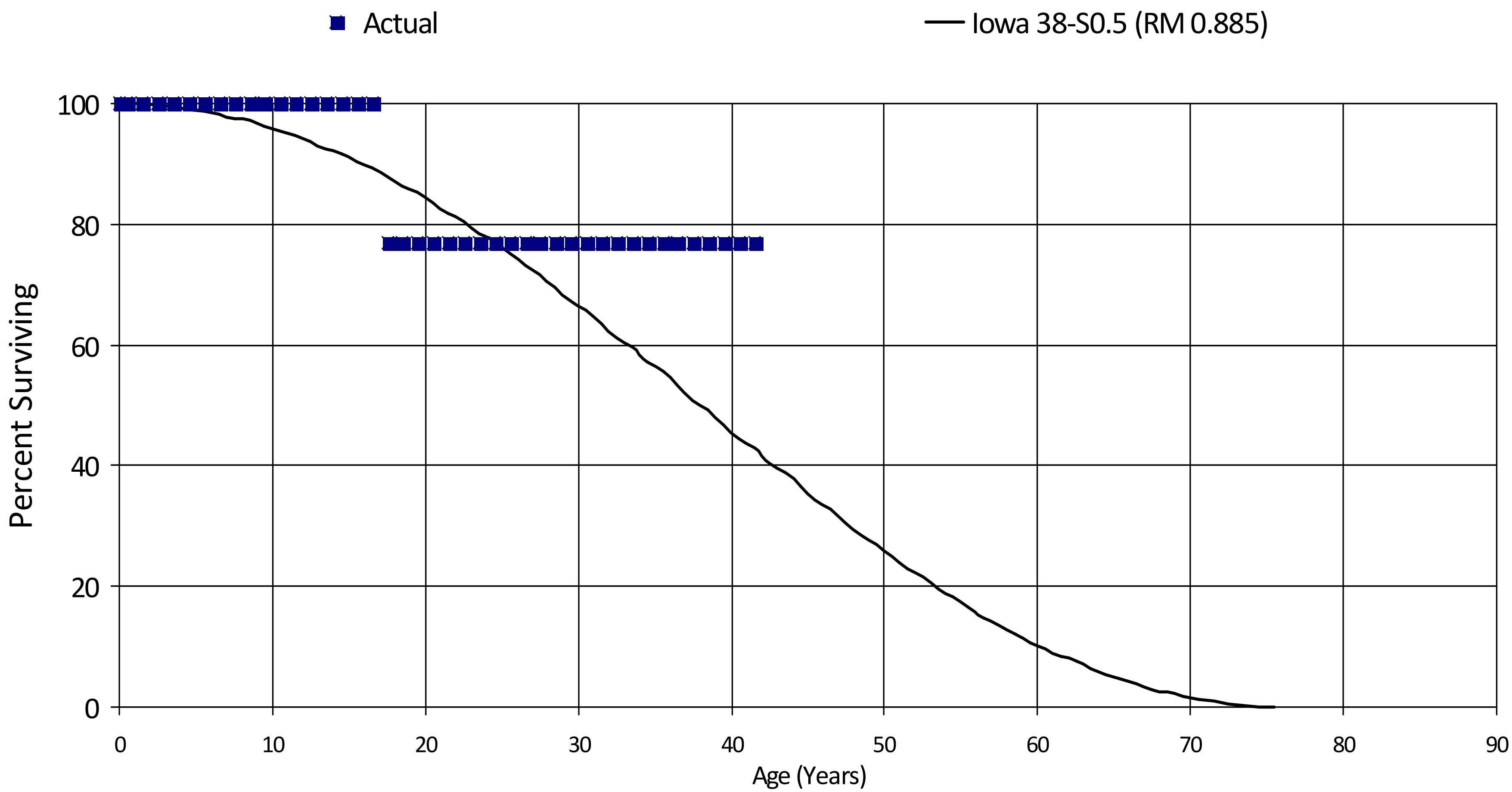
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	44,625,533	0	0.00000	1.00000	100.00
0.5	44,625,533	0	0.00000	1.00000	100.00
1.5	42,843,816	0	0.00000	1.00000	100.00
2.5	42,439,301	229,948	0.00542	0.99458	100.00
3.5	32,706,274	0	0.00000	1.00000	99.46
4.5	22,252,096	0	0.00000	1.00000	99.46
5.5	16,425,871	0	0.00000	1.00000	99.46
6.5	14,141,181	0	0.00000	1.00000	99.46
7.5	13,281,530	0	0.00000	1.00000	99.46
8.5	8,081,627	0	0.00000	1.00000	99.46
9.5	5,523,702	0	0.00000	1.00000	99.46
10.5	4,851,184	0	0.00000	1.00000	99.46
11.5	4,851,184	0	0.00000	1.00000	99.46
12.5	4,851,184	0	0.00000	1.00000	99.46
13.5	4,851,184	0	0.00000	1.00000	99.46
14.5	4,851,184	0	0.00000	1.00000	99.46
15.5	4,828,380	0	0.00000	1.00000	99.46
16.5	3,088,392	0	0.00000	1.00000	99.46
17.5	2,235,545	0	0.00000	1.00000	99.46
18.5	2,235,545	0	0.00000	1.00000	99.46
19.5	2,121,149	0	0.00000	1.00000	99.46
20.5	2,121,149	0	0.00000	1.00000	99.46
21.5	2,121,149	0	0.00000	1.00000	99.46
22.5	2,007,447	0	0.00000	1.00000	99.46
23.5	1,511,313	0	0.00000	1.00000	99.46
24.5	1,059,740	0	0.00000	1.00000	99.46
	Totals:	229,948			

BC Hydro Power Authority

Account 52403 - Oil, < 69 Kv

Placement Band - 1963 - 2009   Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52403 - Oil, < 69 Kv

Placement Band - 1963 - 2009   Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	34,479	0	0.00000	1.00000	100.00
0.5	34,479	0	0.00000	1.00000	100.00
1.5	34,479	0	0.00000	1.00000	100.00
2.5	34,479	0	0.00000	1.00000	100.00
3.5	34,479	0	0.00000	1.00000	100.00
4.5	34,479	0	0.00000	1.00000	100.00
5.5	34,479	0	0.00000	1.00000	100.00
6.5	34,479	0	0.00000	1.00000	100.00
7.5	34,479	0	0.00000	1.00000	100.00
8.5	34,479	0	0.00000	1.00000	100.00
9.5	34,479	0	0.00000	1.00000	100.00
10.5	34,479	0	0.00000	1.00000	100.00
11.5	19,206	0	0.00000	1.00000	100.00
12.5	19,206	0	0.00000	1.00000	100.00
13.5	19,206	0	0.00000	1.00000	100.00
14.5	19,206	0	0.00000	1.00000	100.00
15.5	19,206	0	0.00000	1.00000	100.00
16.5	19,206	4,440	0.23118	0.76882	100.00
17.5	14,765	0	0.00000	1.00000	76.88
18.5	14,765	0	0.00000	1.00000	76.88
19.5	14,765	0	0.00000	1.00000	76.88
20.5	14,765	0	0.00000	1.00000	76.88
21.5	14,765	0	0.00000	1.00000	76.88
22.5	14,678	0	0.00000	1.00000	76.88
23.5	8,283	0	0.00000	1.00000	76.88
24.5	731	0	0.00000	1.00000	76.88
25.5	731	0	0.00000	1.00000	76.88
26.5	731	0	0.00000	1.00000	76.88

BC Hydro Power Authority

Account 52403 - Oil, < 69 Kv

Placement Band - 1963 - 2009   Experience Band - 2014 - 2020

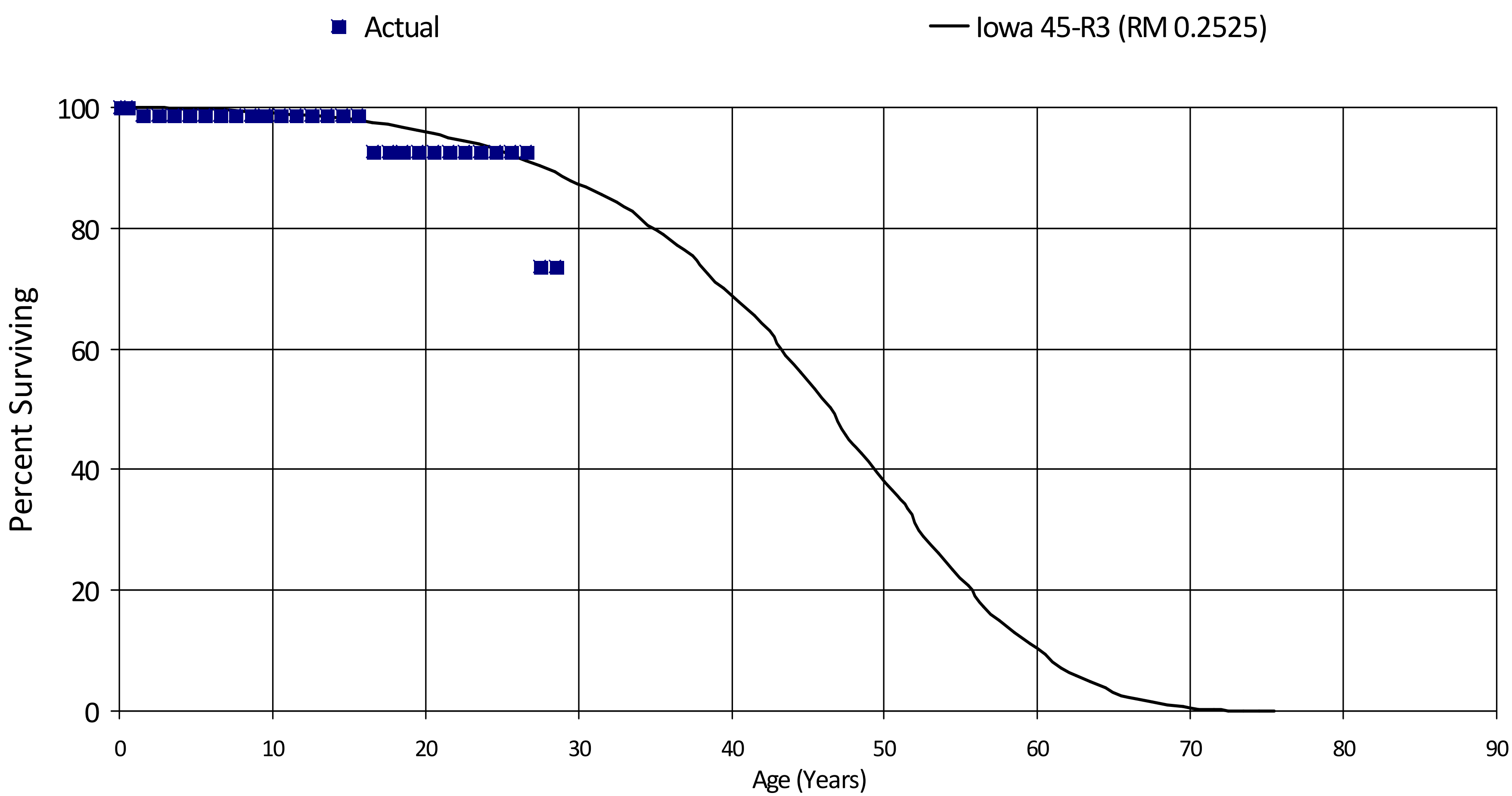
27.5	731	0	0.00000	1.00000	76.88
28.5	731	0	0.00000	1.00000	76.88
29.5	731	0	0.00000	1.00000	76.88
30.5	731	0	0.00000	1.00000	76.88
31.5	731	0	0.00000	1.00000	76.88
32.5	731	0	0.00000	1.00000	76.88
33.5	731	0	0.00000	1.00000	76.88
34.5	731	0	0.00000	1.00000	76.88
35.5	731	0	0.00000	1.00000	76.88
36.5	731	0	0.00000	1.00000	76.88
37.5	731	0	0.00000	1.00000	76.88
38.5	731	0	0.00000	1.00000	76.88
39.5	731	0	0.00000	1.00000	76.88
40.5	731	0	0.00000	1.00000	76.88
41.5	731	0	0.00000	1.00000	76.88
	Totals:	4,440			

BC Hydro Power Authority

Account 52404 - Transformer, Current, Encaps.

Placement Band - 1971 - 2018 Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52404 - Transformer, Current, Encaps.

Placement Band - 1971 - 2018   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	5,213,925	0	0.00000	1.00000	100.00
0.5	5,213,925	71,051	0.01363	0.98637	100.00
1.5	5,142,874	0	0.00000	1.00000	98.64
2.5	5,015,061	0	0.00000	1.00000	98.64
3.5	4,926,171	0	0.00000	1.00000	98.64
4.5	3,536,076	2	0.00000	1.00000	98.64
5.5	3,536,074	0	0.00000	1.00000	98.64
6.5	3,536,074	0	0.00000	1.00000	98.64
7.5	1,611,340	0	0.00000	1.00000	98.64
8.5	1,176,252	0	0.00000	1.00000	98.64
9.5	1,176,252	0	0.00000	1.00000	98.64
10.5	1,108,623	0	0.00000	1.00000	98.64
11.5	857,615	0	0.00000	1.00000	98.64
12.5	804,937	0	0.00000	1.00000	98.64
13.5	603,174	0	0.00000	1.00000	98.64
14.5	592,550	0	0.00000	1.00000	98.64
15.5	553,420	33,253	0.06009	0.93991	98.64
16.5	505,092	0	0.00000	1.00000	92.71
17.5	441,623	0	0.00000	1.00000	92.71
18.5	353,436	0	0.00000	1.00000	92.71
19.5	353,436	0	0.00000	1.00000	92.71
20.5	353,436	0	0.00000	1.00000	92.71
21.5	353,436	0	0.00000	1.00000	92.71
22.5	336,490	0	0.00000	1.00000	92.71
23.5	336,485	0	0.00000	1.00000	92.71
24.5	287,466	0	0.00000	1.00000	92.71
25.5	249,643	0	0.00000	1.00000	92.71
26.5	95,661	19,809	0.20707	0.79293	92.71

BC Hydro Power Authority

Account 52404 - Transformer, Current, Encaps.

Placement Band - 1971 - 2018 Experience Band - 2012 - 2020

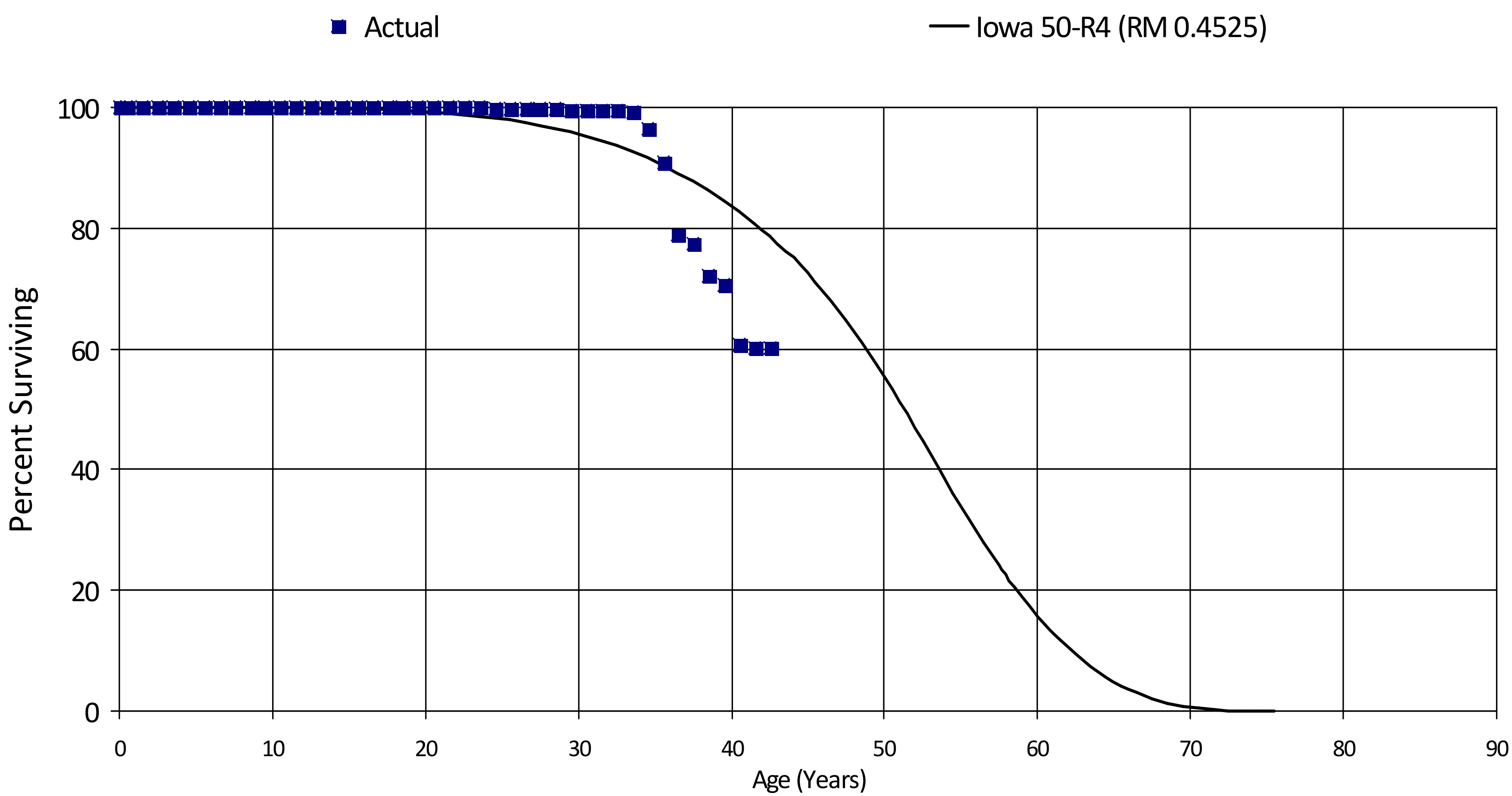
27.5	54,155	0	0.00000	1.00000	73.51
28.5	54,155	0	0.00000	1.00000	73.51
	Totals:	124,115			

BC Hydro Power Authority

Account 52405 - Transformer, Current, Comp. Pool

Placement Band - 1961 - 2017 Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52405 - Transformer, Current, Comp. Pool

Placement Band - 1961 - 2017   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	29,799,898	0	0.00000	1.00000	100.00
0.5	29,799,898	0	0.00000	1.00000	100.00
1.5	29,799,898	0	0.00000	1.00000	100.00
2.5	29,799,898	0	0.00000	1.00000	100.00
3.5	28,096,698	0	0.00000	1.00000	100.00
4.5	27,521,232	0	0.00000	1.00000	100.00
5.5	22,936,390	0	0.00000	1.00000	100.00
6.5	22,064,418	0	0.00000	1.00000	100.00
7.5	22,064,418	0	0.00000	1.00000	100.00
8.5	17,859,739	0	0.00000	1.00000	100.00
9.5	8,777,889	0	0.00000	1.00000	100.00
10.5	8,005,430	0	0.00000	1.00000	100.00
11.5	8,005,430	0	0.00000	1.00000	100.00
12.5	7,869,707	2,814	0.00036	0.99964	100.00
13.5	7,866,893	0	0.00000	1.00000	99.96
14.5	7,796,270	0	0.00000	1.00000	99.96
15.5	7,796,270	0	0.00000	1.00000	99.96
16.5	7,789,231	0	0.00000	1.00000	99.96
17.5	7,520,545	0	0.00000	1.00000	99.96
18.5	7,520,545	0	0.00000	1.00000	99.96
19.5	7,520,545	0	0.00000	1.00000	99.96
20.5	7,520,545	0	0.00000	1.00000	99.96
21.5	7,520,545	0	0.00000	1.00000	99.96
22.5	7,520,545	0	0.00000	1.00000	99.96
23.5	7,444,665	6,518	0.00088	0.99912	99.96
24.5	7,438,147	0	0.00000	1.00000	99.87
25.5	7,438,147	0	0.00000	1.00000	99.87
26.5	7,274,028	0	0.00000	1.00000	99.87

BC Hydro Power Authority

Account 52405 - Transformer, Current, Comp. Pool

Placement Band - 1961 - 2017 Experience Band - 2011 - 2020

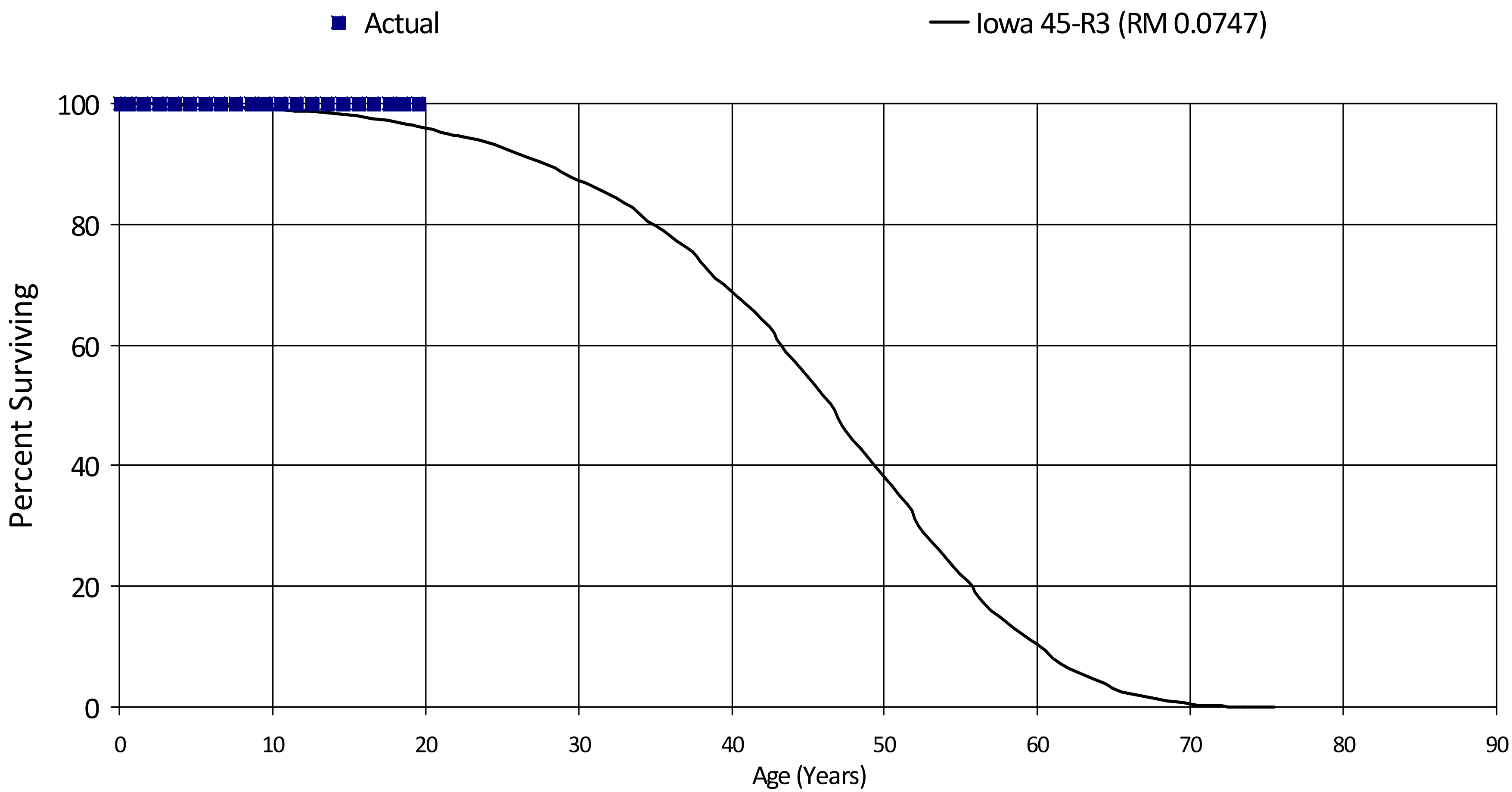
27.5	6,359,755	0	0.00000	1.00000	99.87
28.5	6,309,059	25,379	0.00402	0.99598	99.87
29.5	6,258,083	0	0.00000	1.00000	99.47
30.5	5,841,230	0	0.00000	1.00000	99.47
31.5	5,478,443	0	0.00000	1.00000	99.47
32.5	5,310,106	6,132	0.00115	0.99885	99.47
33.5	5,222,940	156,744	0.03001	0.96999	99.36
34.5	3,951,983	230,240	0.05826	0.94174	96.38
35.5	3,358,766	441,328	0.13140	0.86860	90.76
36.5	2,884,983	56,044	0.01943	0.98057	78.83
37.5	2,805,610	191,819	0.06837	0.93163	77.30
38.5	2,554,911	48,651	0.01904	0.98096	72.01
39.5	2,389,963	340,435	0.14244	0.85756	70.64
40.5	1,352,723	8,049	0.00595	0.99405	60.58
41.5	508,488	0	0.00000	1.00000	60.22
42.5	395,971	0	0.00000	1.00000	60.22
	Totals:	1,514,153			

BC Hydro Power Authority

Account 52406 - Comb Ct & Vt Transformer

Placement Band - 2000 - 2018   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52406 - Comb Ct & Vt Transformer

Placement Band - 2000 - 2018 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

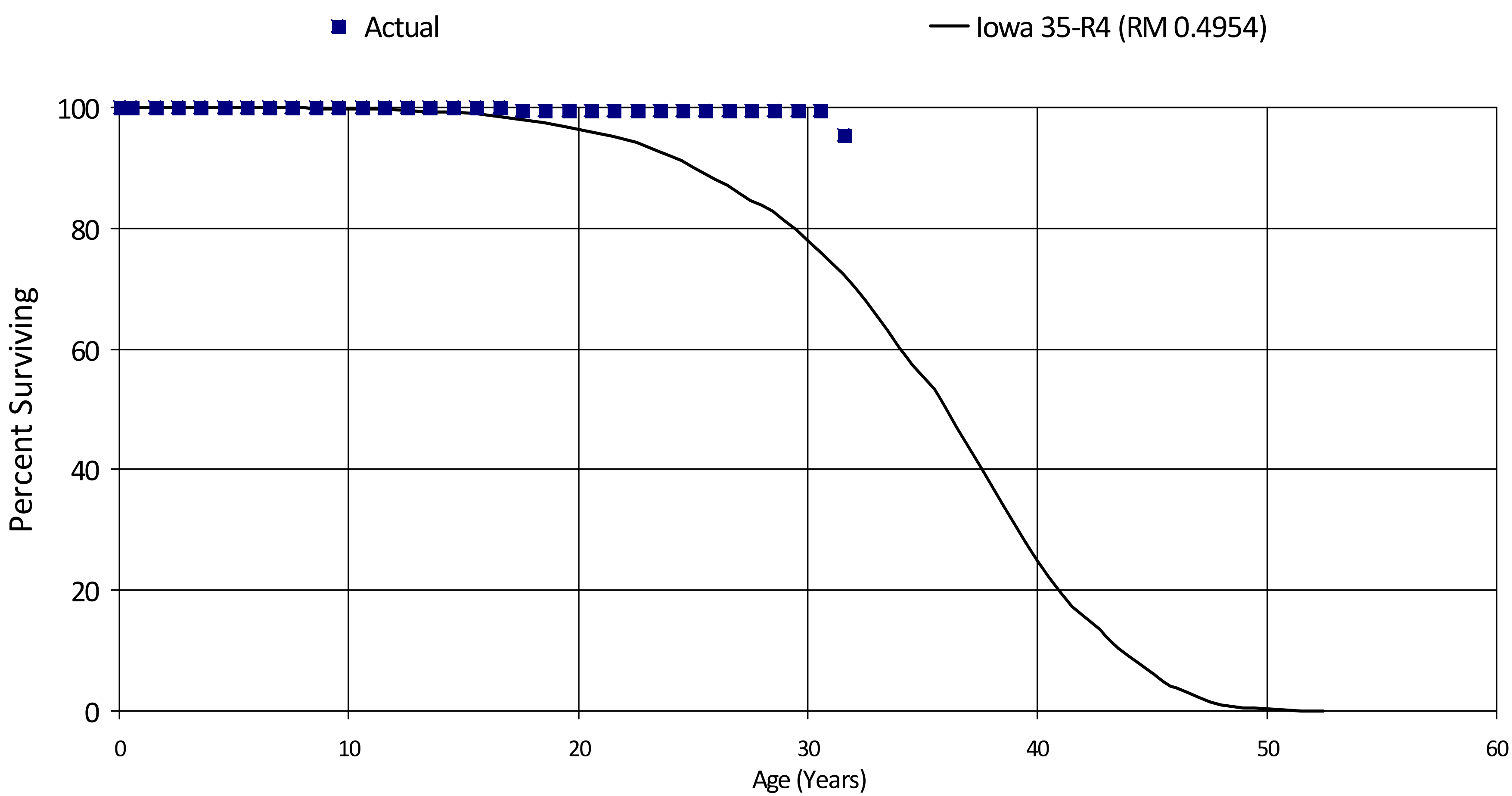
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,684,562	0	0.00000	1.00000	100.00
0.5	2,684,562	0	0.00000	1.00000	100.00
1.5	2,684,562	0	0.00000	1.00000	100.00
2.5	2,169,797	0	0.00000	1.00000	100.00
3.5	2,011,344	0	0.00000	1.00000	100.00
4.5	1,949,758	0	0.00000	1.00000	100.00
5.5	1,949,758	0	0.00000	1.00000	100.00
6.5	1,775,860	0	0.00000	1.00000	100.00
7.5	424,965	0	0.00000	1.00000	100.00
8.5	404,294	0	0.00000	1.00000	100.00
9.5	404,294	0	0.00000	1.00000	100.00
10.5	386,758	0	0.00000	1.00000	100.00
11.5	386,758	0	0.00000	1.00000	100.00
12.5	386,758	0	0.00000	1.00000	100.00
13.5	386,758	0	0.00000	1.00000	100.00
14.5	386,758	0	0.00000	1.00000	100.00
15.5	386,758	0	0.00000	1.00000	100.00
16.5	304,968	0	0.00000	1.00000	100.00
17.5	83,642	0	0.00000	1.00000	100.00
18.5	83,642	0	0.00000	1.00000	100.00
19.5	83,642	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 52501 - Transformer, Voltage, Capacitor

Placement Band - 1976 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52501 - Transformer, Voltage, Capacitor

Placement Band - 1976 - 2020 Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	68,071,485	0	0.00000	1.00000	100.00
0.5	67,617,503	61,183	0.00090	0.99910	100.00
1.5	65,013,421	0	0.00000	1.00000	99.91
2.5	60,202,442	0	0.00000	1.00000	99.91
3.5	49,308,448	0	0.00000	1.00000	99.91
4.5	40,290,115	0	0.00000	1.00000	99.91
5.5	32,379,700	0	0.00000	1.00000	99.91
6.5	28,987,573	0	0.00000	1.00000	99.91
7.5	25,461,811	0	0.00000	1.00000	99.91
8.5	20,949,341	0	0.00000	1.00000	99.91
9.5	6,381,352	0	0.00000	1.00000	99.91
10.5	5,623,887	0	0.00000	1.00000	99.91
11.5	4,766,192	0	0.00000	1.00000	99.91
12.5	4,155,217	0	0.00000	1.00000	99.91
13.5	3,570,135	0	0.00000	1.00000	99.91
14.5	3,269,797	0	0.00000	1.00000	99.91
15.5	2,698,040	0	0.00000	1.00000	99.91
16.5	2,437,995	7,997	0.00328	0.99672	99.91
17.5	2,135,086	0	0.00000	1.00000	99.58
18.5	1,949,959	0	0.00000	1.00000	99.58
19.5	1,944,478	0	0.00000	1.00000	99.58
20.5	1,891,578	0	0.00000	1.00000	99.58
21.5	1,801,610	0	0.00000	1.00000	99.58
22.5	1,662,116	0	0.00000	1.00000	99.58
23.5	1,546,844	0	0.00000	1.00000	99.58
24.5	1,228,070	0	0.00000	1.00000	99.58
25.5	1,167,264	0	0.00000	1.00000	99.58
26.5	941,788	0	0.00000	1.00000	99.58

BC Hydro Power Authority

Account 52501 - Transformer, Voltage, Capacitor

Placement Band - 1976 - 2020 Experience Band - 2013 - 2020

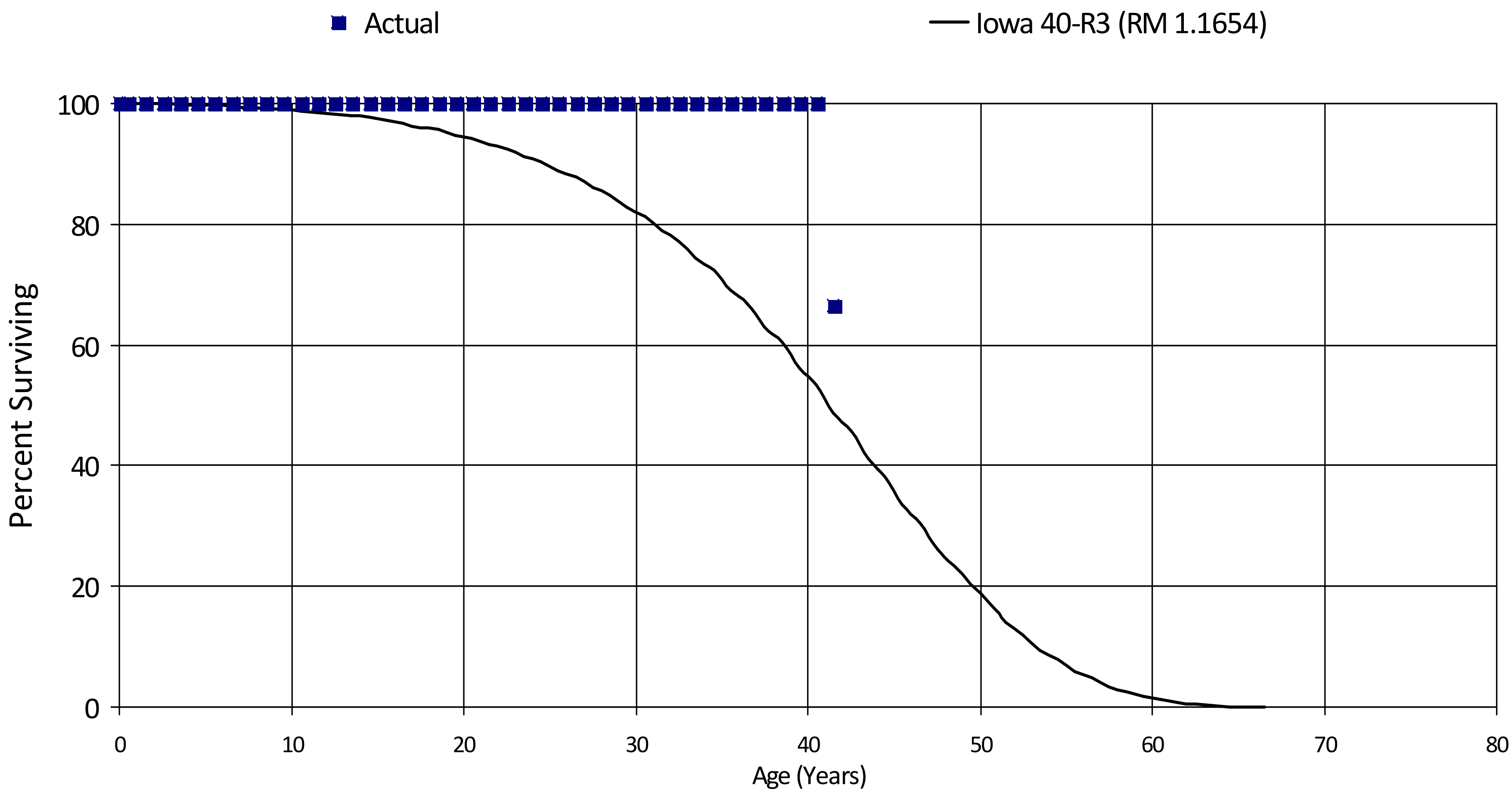
27.5	941,788	0	0.00000	1.00000	99.58
28.5	927,675	0	0.00000	1.00000	99.58
29.5	902,504	0	0.00000	1.00000	99.58
30.5	827,326	33,951	0.04104	0.95896	99.58
31.5	759,663	153,758	0.20240	0.79760	95.49
	Totals:	256,889			

BC Hydro Power Authority

Account 52502 - Transformer, Voltage, Oil-Fill

Placement Band - 1971 - 2018 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52502 - Transformer, Voltage, Oil-Fill

Placement Band - 1971 - 2018   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	6,953,488	0	0.00000	1.00000	100.00
0.5	6,953,488	0	0.00000	1.00000	100.00
1.5	6,953,488	0	0.00000	1.00000	100.00
2.5	6,779,938	0	0.00000	1.00000	100.00
3.5	6,402,665	0	0.00000	1.00000	100.00
4.5	6,073,888	0	0.00000	1.00000	100.00
5.5	1,930,584	0	0.00000	1.00000	100.00
6.5	1,915,900	0	0.00000	1.00000	100.00
7.5	1,884,700	0	0.00000	1.00000	100.00
8.5	1,693,332	0	0.00000	1.00000	100.00
9.5	1,283,438	0	0.00000	1.00000	100.00
10.5	1,211,735	0	0.00000	1.00000	100.00
11.5	781,029	0	0.00000	1.00000	100.00
12.5	516,627	0	0.00000	1.00000	100.00
13.5	516,627	0	0.00000	1.00000	100.00
14.5	516,627	0	0.00000	1.00000	100.00
15.5	516,627	0	0.00000	1.00000	100.00
16.5	516,627	0	0.00000	1.00000	100.00
17.5	516,252	0	0.00000	1.00000	100.00
18.5	516,252	0	0.00000	1.00000	100.00
19.5	516,252	0	0.00000	1.00000	100.00
20.5	515,659	0	0.00000	1.00000	100.00
21.5	493,584	0	0.00000	1.00000	100.00
22.5	493,329	0	0.00000	1.00000	100.00
23.5	420,698	0	0.00000	1.00000	100.00
24.5	410,195	0	0.00000	1.00000	100.00
25.5	360,264	0	0.00000	1.00000	100.00
26.5	193,124	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 52502 - Transformer, Voltage, Oil-Fill

Placement Band - 1971 - 2018 Experience Band - 2013 - 2020

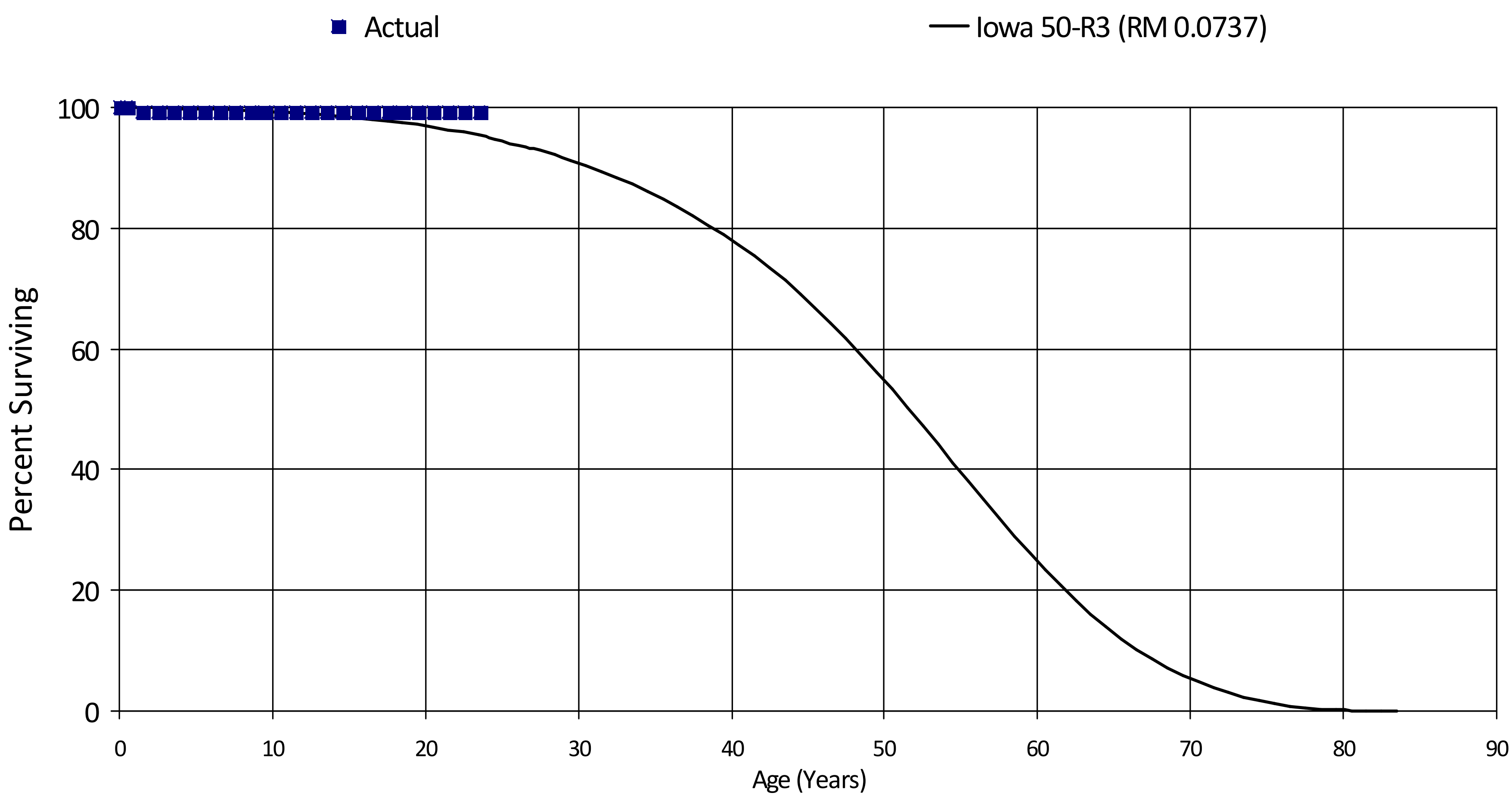
27.5	193,124	0	0.00000	1.00000	100.00
28.5	169,649	0	0.00000	1.00000	100.00
29.5	169,649	0	0.00000	1.00000	100.00
30.5	169,649	0	0.00000	1.00000	100.00
31.5	161,105	0	0.00000	1.00000	100.00
32.5	157,180	0	0.00000	1.00000	100.00
33.5	153,262	0	0.00000	1.00000	100.00
34.5	153,262	0	0.00000	1.00000	100.00
35.5	150,295	0	0.00000	1.00000	100.00
36.5	148,526	0	0.00000	1.00000	100.00
37.5	148,526	0	0.00000	1.00000	100.00
38.5	147,264	0	0.00000	1.00000	100.00
39.5	139,496	0	0.00000	1.00000	100.00
40.5	139,324	46,643	0.33478	0.66522	100.00
41.5	92,681	92,681	1.00000		66.52
	Totals:	139,324			

BC Hydro Power Authority

Account 52503 - Transformer, Voltage, Gas-Fill

Placement Band - 1995 - 2018 Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52503 - Transformer, Voltage, Gas-Fill

Placement Band - 1995 - 2018   Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

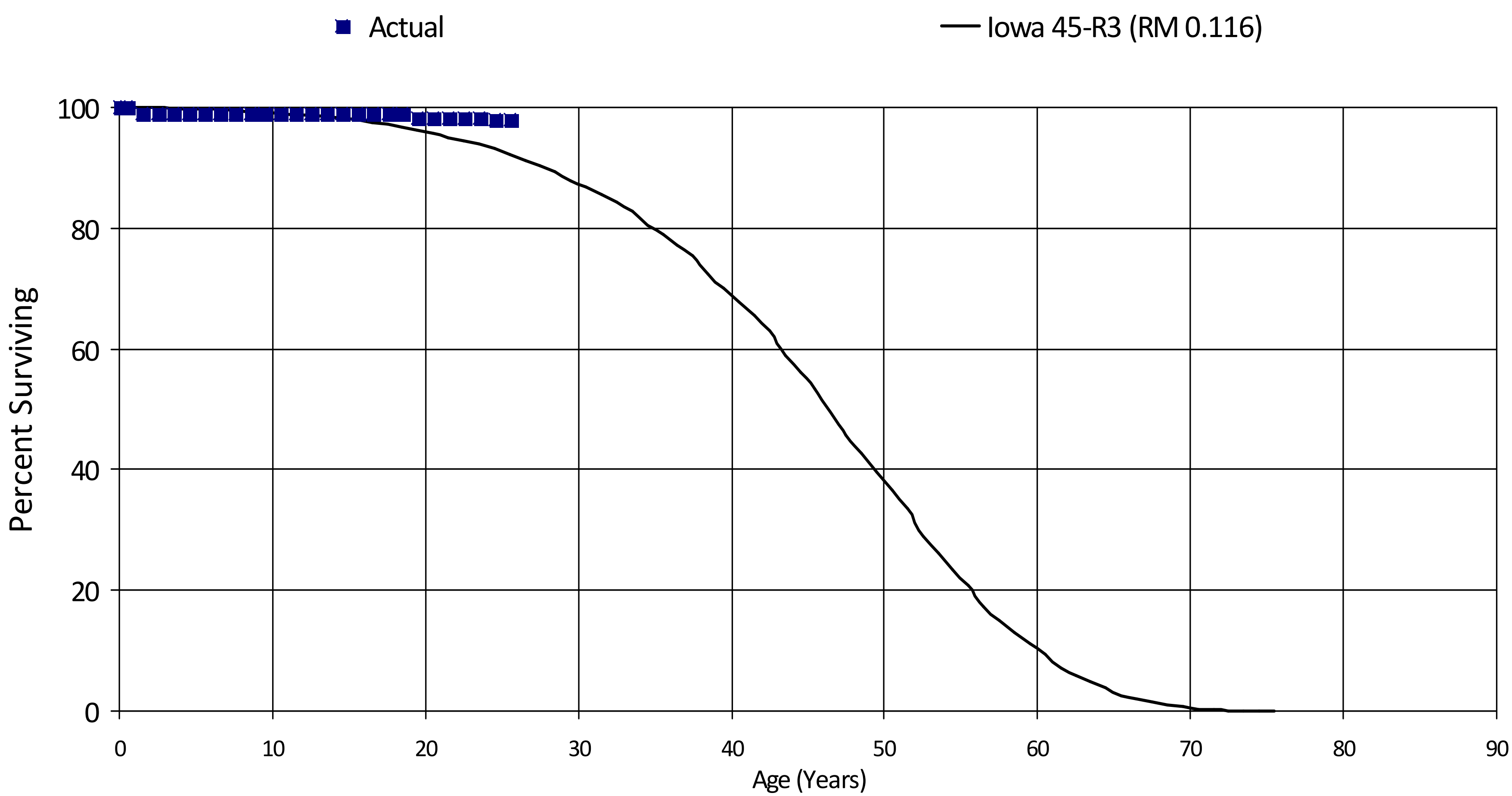
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	7,737,068	0	0.00000	1.00000	100.00
0.5	7,737,068	67,104	0.00867	0.99133	100.00
1.5	7,669,964	0	0.00000	1.00000	99.13
2.5	5,174,050	0	0.00000	1.00000	99.13
3.5	4,300,220	0	0.00000	1.00000	99.13
4.5	3,305,777	0	0.00000	1.00000	99.13
5.5	3,035,426	0	0.00000	1.00000	99.13
6.5	2,830,763	0	0.00000	1.00000	99.13
7.5	2,830,763	0	0.00000	1.00000	99.13
8.5	1,127,027	0	0.00000	1.00000	99.13
9.5	1,127,027	0	0.00000	1.00000	99.13
10.5	1,075,777	0	0.00000	1.00000	99.13
11.5	1,072,804	0	0.00000	1.00000	99.13
12.5	745,695	0	0.00000	1.00000	99.13
13.5	707,637	0	0.00000	1.00000	99.13
14.5	707,637	0	0.00000	1.00000	99.13
15.5	346,847	0	0.00000	1.00000	99.13
16.5	168,453	0	0.00000	1.00000	99.13
17.5	133,129	0	0.00000	1.00000	99.13
18.5	133,129	0	0.00000	1.00000	99.13
19.5	133,129	0	0.00000	1.00000	99.13
20.5	133,129	0	0.00000	1.00000	99.13
21.5	133,129	0	0.00000	1.00000	99.13
22.5	123,053	0	0.00000	1.00000	99.13
23.5	123,053	0	0.00000	1.00000	99.13
	Totals:	67,104			

BC Hydro Power Authority

Account 52504 - Transformer, Voltage, Encaps.

Placement Band - 1974 - 2019   Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52504 - Transformer, Voltage, Encaps.

Placement Band - 1974 - 2019   Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

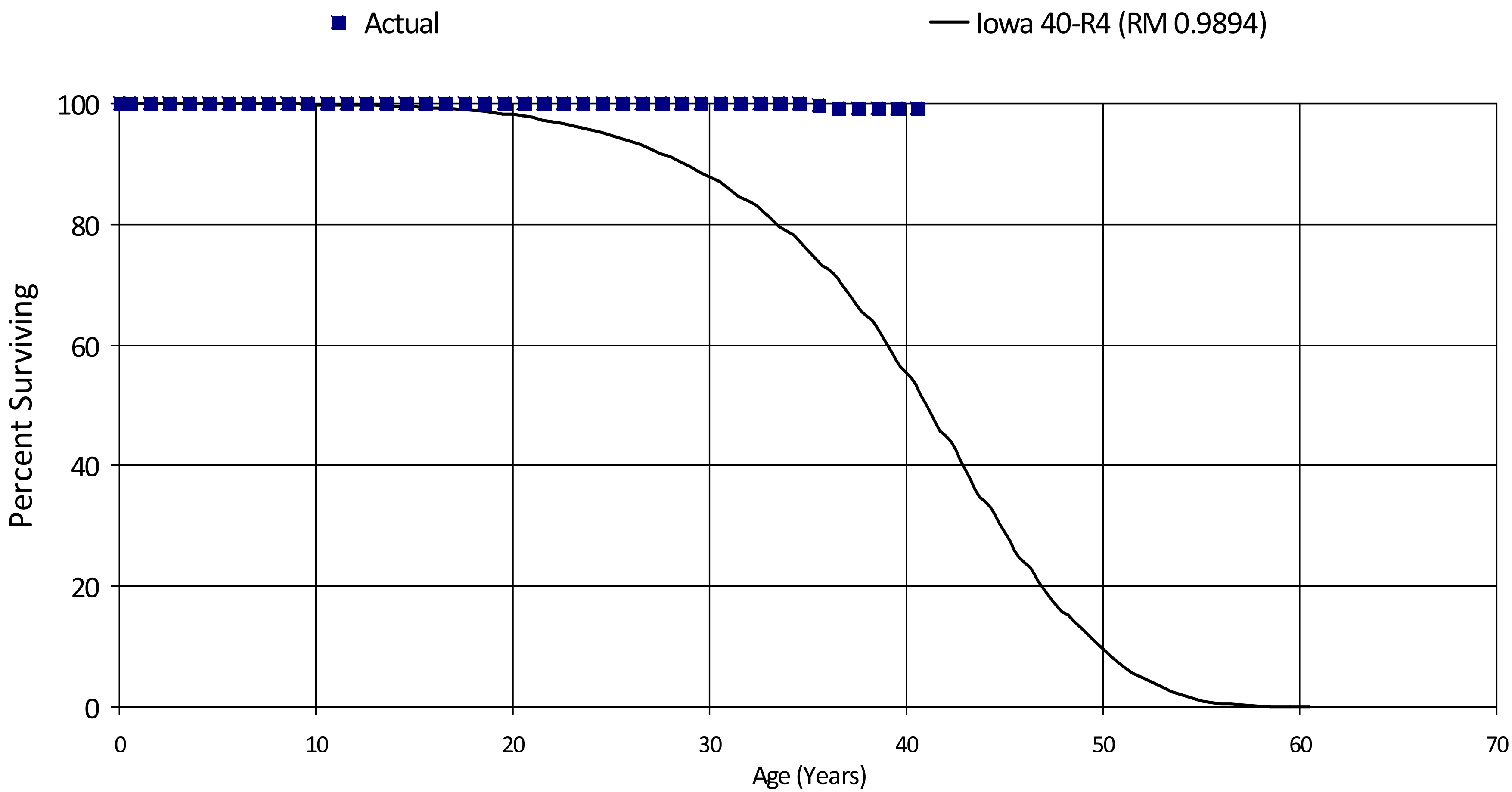
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	8,731,259	0	0.00000	1.00000	100.00
0.5	8,731,259	80,919	0.00927	0.99073	100.00
1.5	8,040,979	0	0.00000	1.00000	99.07
2.5	7,029,951	0	0.00000	1.00000	99.07
3.5	6,844,772	0	0.00000	1.00000	99.07
4.5	6,295,572	0	0.00000	1.00000	99.07
5.5	6,054,349	0	0.00000	1.00000	99.07
6.5	5,767,661	0	0.00000	1.00000	99.07
7.5	5,361,664	0	0.00000	1.00000	99.07
8.5	3,862,064	0	0.00000	1.00000	99.07
9.5	3,779,506	0	0.00000	1.00000	99.07
10.5	3,493,046	0	0.00000	1.00000	99.07
11.5	3,118,580	0	0.00000	1.00000	99.07
12.5	2,716,665	0	0.00000	1.00000	99.07
13.5	2,307,109	0	0.00000	1.00000	99.07
14.5	2,003,364	0	0.00000	1.00000	99.07
15.5	1,925,457	0	0.00000	1.00000	99.07
16.5	1,721,709	0	0.00000	1.00000	99.07
17.5	1,348,280	0	0.00000	1.00000	99.07
18.5	1,273,483	9,753	0.00766	0.99234	99.07
19.5	1,170,852	0	0.00000	1.00000	98.31
20.5	937,617	0	0.00000	1.00000	98.31
21.5	821,557	789	0.00096	0.99904	98.31
22.5	725,880	0	0.00000	1.00000	98.22
23.5	543,687	836	0.00154	0.99846	98.22
24.5	450,942	0	0.00000	1.00000	98.07
25.5	251,361	0	0.00000	1.00000	98.07
	Totals:	92,297			

BC Hydro Power Authority

Account 52505 - Transformer, Volt, Comp. Pool

Placement Band - 1971 - 2016 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52505 - Transformer, Volt, Comp. Pool

Placement Band - 1971 - 2016   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	6,595,795	0	0.00000	1.00000	100.00
0.5	6,595,795	0	0.00000	1.00000	100.00
1.5	6,595,795	0	0.00000	1.00000	100.00
2.5	6,595,795	0	0.00000	1.00000	100.00
3.5	6,595,795	0	0.00000	1.00000	100.00
4.5	6,538,580	0	0.00000	1.00000	100.00
5.5	6,464,661	0	0.00000	1.00000	100.00
6.5	6,289,313	0	0.00000	1.00000	100.00
7.5	6,269,696	0	0.00000	1.00000	100.00
8.5	6,160,104	0	0.00000	1.00000	100.00
9.5	2,334,977	0	0.00000	1.00000	100.00
10.5	1,733,746	0	0.00000	1.00000	100.00
11.5	1,733,746	0	0.00000	1.00000	100.00
12.5	1,733,746	0	0.00000	1.00000	100.00
13.5	1,733,746	0	0.00000	1.00000	100.00
14.5	1,683,110	0	0.00000	1.00000	100.00
15.5	1,626,632	0	0.00000	1.00000	100.00
16.5	1,626,632	0	0.00000	1.00000	100.00
17.5	1,464,499	0	0.00000	1.00000	100.00
18.5	1,459,160	0	0.00000	1.00000	100.00
19.5	1,445,098	0	0.00000	1.00000	100.00
20.5	1,420,925	0	0.00000	1.00000	100.00
21.5	1,409,360	0	0.00000	1.00000	100.00
22.5	1,376,388	0	0.00000	1.00000	100.00
23.5	1,354,922	0	0.00000	1.00000	100.00
24.5	1,097,111	758	0.00069	0.99931	100.00
25.5	1,074,281	0	0.00000	1.00000	99.93
26.5	1,047,200	0	0.00000	1.00000	99.93

BC Hydro Power Authority

Account 52505 - Transformer, Volt, Comp. Pool

Placement Band - 1971 - 2016 Experience Band - 2013 - 2020

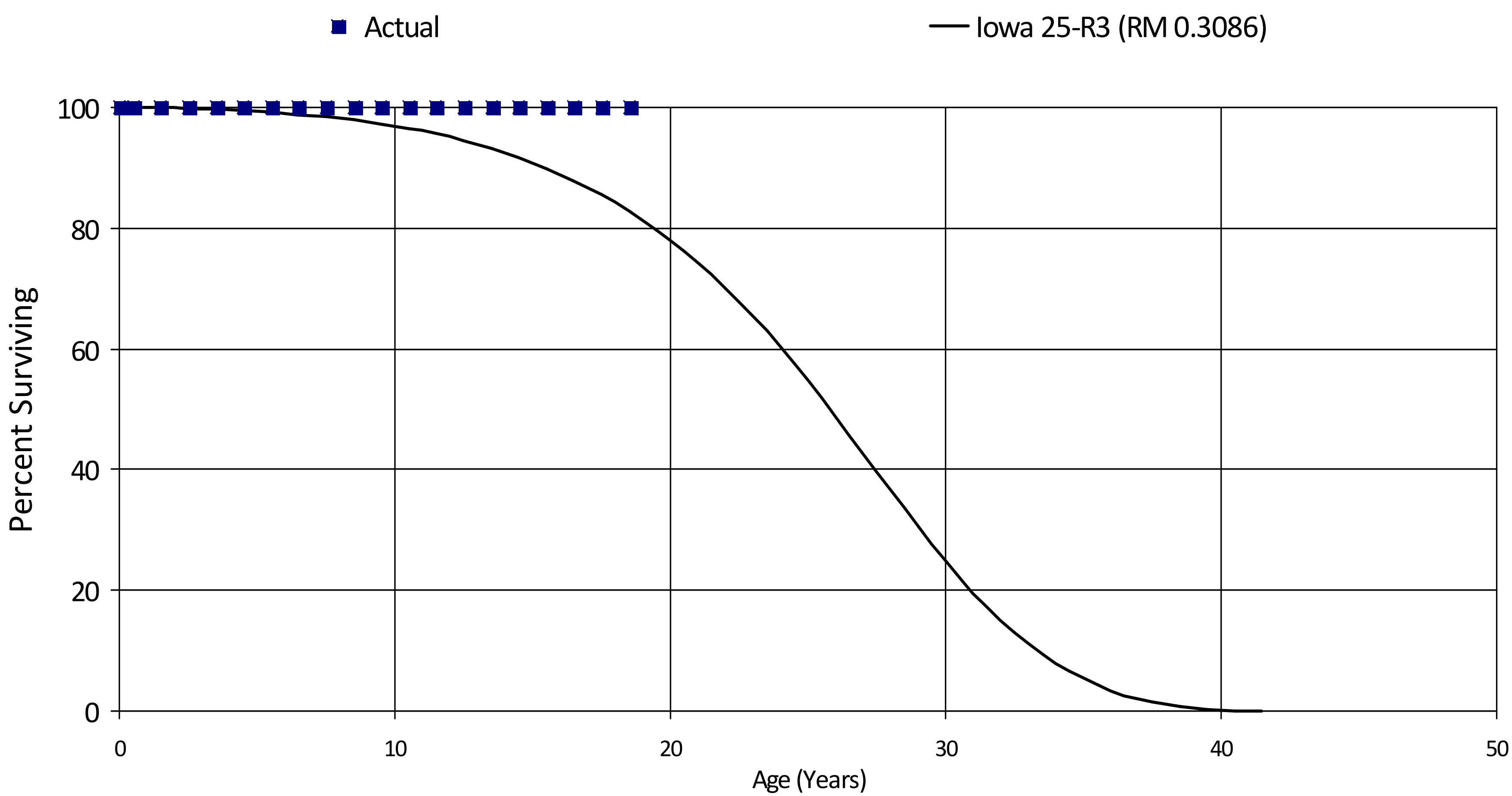
27.5	1,046,968	0	0.00000	1.00000	99.93
28.5	1,043,006	0	0.00000	1.00000	99.93
29.5	891,154	0	0.00000	1.00000	99.93
30.5	837,064	0	0.00000	1.00000	99.93
31.5	689,797	0	0.00000	1.00000	99.93
32.5	672,907	0	0.00000	1.00000	99.93
33.5	660,240	0	0.00000	1.00000	99.93
34.5	658,074	2,040	0.00310	0.99690	99.93
35.5	592,889	1,714	0.00289	0.99711	99.62
36.5	566,891	316	0.00056	0.99944	99.33
37.5	550,694	0	0.00000	1.00000	99.27
38.5	488,248	0	0.00000	1.00000	99.27
39.5	431,370	0	0.00000	1.00000	99.27
40.5	255,020	218,597	0.85717	0.14283	99.27
	Totals:	223,425			

BC Hydro Power Authority

Account 52601 - Mobile Substations

Placement Band - 1977 - 2015 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 52601 - Mobile Substations

Placement Band - 1977 - 2015   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

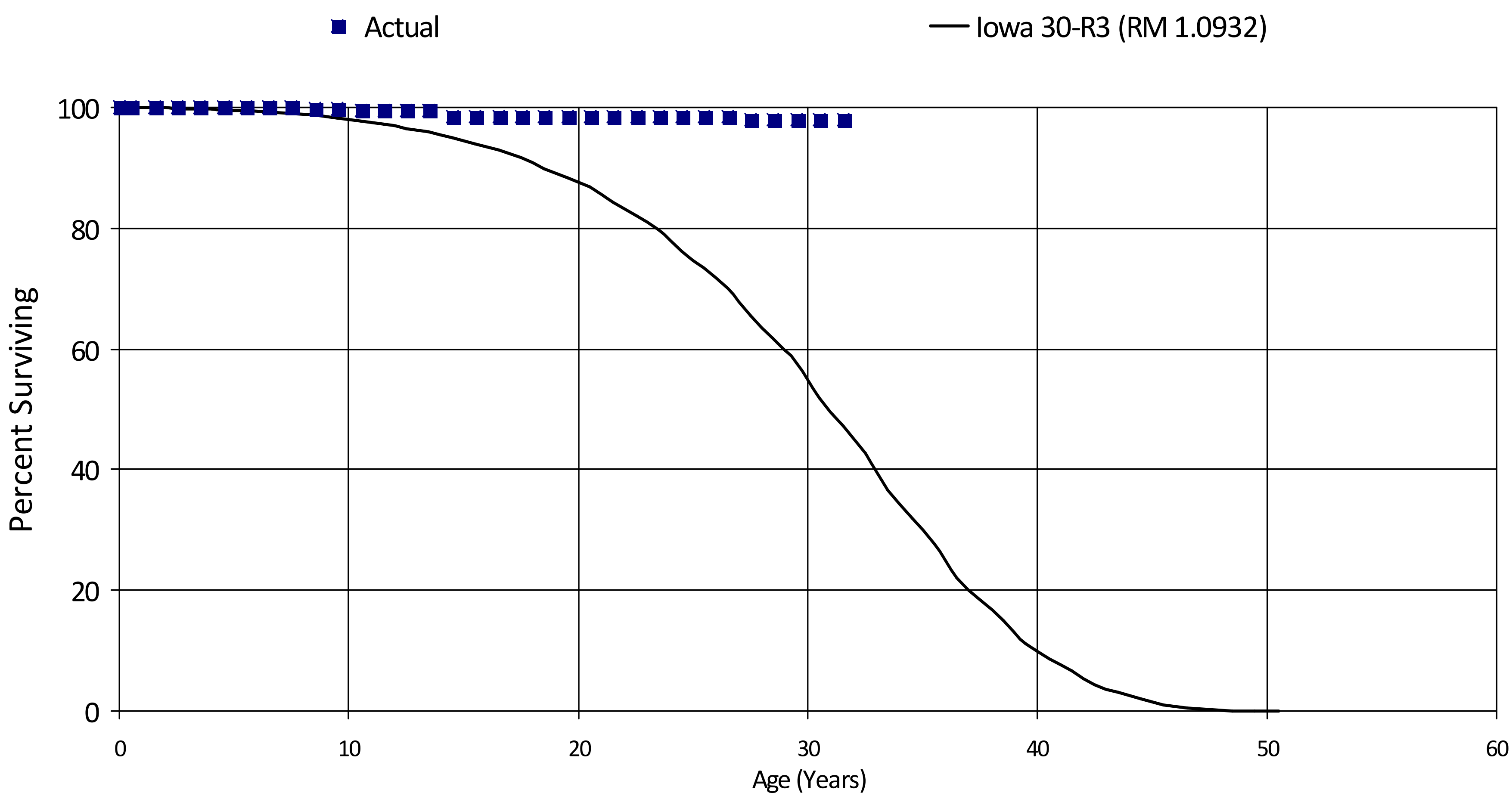
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	9,108,997	0	0.00000	1.00000	100.00
0.5	9,108,997	0	0.00000	1.00000	100.00
1.5	9,108,997	0	0.00000	1.00000	100.00
2.5	9,108,997	0	0.00000	1.00000	100.00
3.5	9,108,997	0	0.00000	1.00000	100.00
4.5	9,108,997	0	0.00000	1.00000	100.00
5.5	3,346,549	0	0.00000	1.00000	100.00
6.5	3,346,549	0	0.00000	1.00000	100.00
7.5	3,346,549	0	0.00000	1.00000	100.00
8.5	900,600	0	0.00000	1.00000	100.00
9.5	900,600	0	0.00000	1.00000	100.00
10.5	900,600	0	0.00000	1.00000	100.00
11.5	835,596	0	0.00000	1.00000	100.00
12.5	835,596	0	0.00000	1.00000	100.00
13.5	835,596	0	0.00000	1.00000	100.00
14.5	835,596	0	0.00000	1.00000	100.00
15.5	835,596	0	0.00000	1.00000	100.00
16.5	835,596	0	0.00000	1.00000	100.00
17.5	835,596	0	0.00000	1.00000	100.00
18.5	835,596	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 53101 - Capacitor, Shunt

Placement Band - 1953 - 2018 Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 53101 - Capacitor, Shunt

Placement Band - 1953 - 2018   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	25,465,488	0	0.00000	1.00000	100.00
0.5	25,465,488	0	0.00000	1.00000	100.00
1.5	25,465,488	0	0.00000	1.00000	100.00
2.5	24,140,338	0	0.00000	1.00000	100.00
3.5	23,419,213	0	0.00000	1.00000	100.00
4.5	19,615,477	1,930	0.00010	0.99990	100.00
5.5	18,346,104	0	0.00000	1.00000	99.99
6.5	17,575,800	0	0.00000	1.00000	99.99
7.5	17,575,800	47,779	0.00272	0.99728	99.99
8.5	15,069,425	0	0.00000	1.00000	99.72
9.5	11,527,114	12,501	0.00108	0.99892	99.72
10.5	11,493,216	0	0.00000	1.00000	99.61
11.5	9,490,843	0	0.00000	1.00000	99.61
12.5	8,272,819	0	0.00000	1.00000	99.61
13.5	7,091,308	75,928	0.01071	0.98929	99.61
14.5	5,910,512	0	0.00000	1.00000	98.54
15.5	5,910,512	0	0.00000	1.00000	98.54
16.5	5,546,925	0	0.00000	1.00000	98.54
17.5	5,335,286	0	0.00000	1.00000	98.54
18.5	5,013,166	0	0.00000	1.00000	98.54
19.5	4,862,806	0	0.00000	1.00000	98.54
20.5	4,862,806	0	0.00000	1.00000	98.54
21.5	4,862,806	0	0.00000	1.00000	98.54
22.5	4,674,193	0	0.00000	1.00000	98.54
23.5	3,787,126	0	0.00000	1.00000	98.54
24.5	3,751,669	0	0.00000	1.00000	98.54
25.5	2,790,156	0	0.00000	1.00000	98.54
26.5	2,143,868	10,827	0.00505	0.99495	98.54

BC Hydro Power Authority

Account 53101 - Capacitor, Shunt

Placement Band - 1953 - 2018   Experience Band - 2012 - 2020

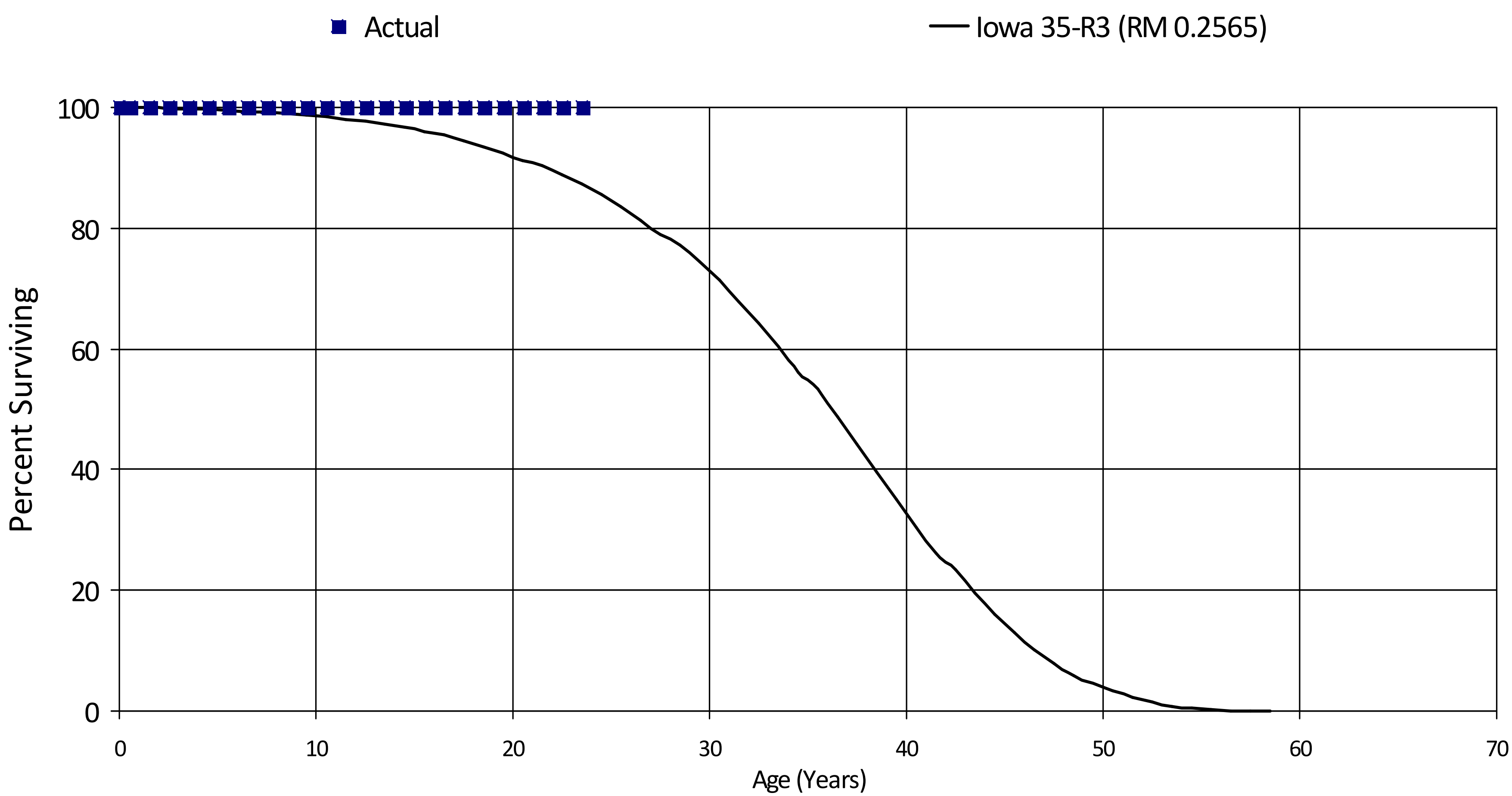
27.5	1,709,899	0	0.00000	1.00000	98.04
28.5	1,695,326	0	0.00000	1.00000	98.04
29.5	1,594,617	2,391	0.00150	0.99850	98.04
30.5	1,366,191	0	0.00000	1.00000	97.89
31.5	1,303,958	23,865	0.01830	0.98170	97.89
	Totals:	175,221			

BC Hydro Power Authority

Account 53201 - Capacitor, Series

Placement Band - 1971 - 2018 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 53201 - Capacitor, Series

Placement Band - 1971 - 2018   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

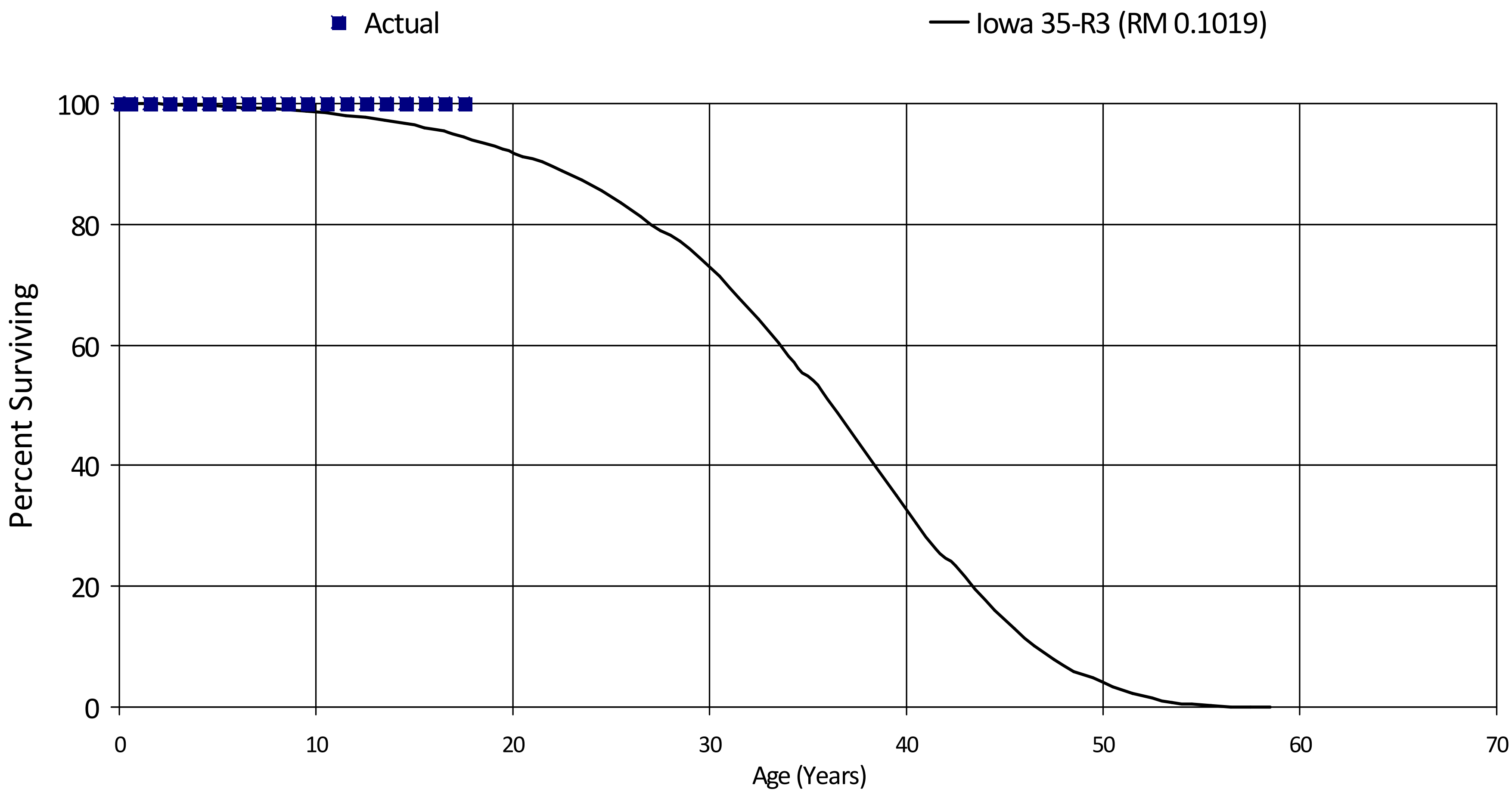
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	44,954,653	0	0.00000	1.00000	100.00
0.5	44,954,653	0	0.00000	1.00000	100.00
1.5	44,954,653	0	0.00000	1.00000	100.00
2.5	44,665,638	0	0.00000	1.00000	100.00
3.5	44,458,573	0	0.00000	1.00000	100.00
4.5	33,086,333	0	0.00000	1.00000	100.00
5.5	32,792,188	0	0.00000	1.00000	100.00
6.5	26,421,521	0	0.00000	1.00000	100.00
7.5	12,137,466	0	0.00000	1.00000	100.00
8.5	11,889,409	0	0.00000	1.00000	100.00
9.5	11,889,409	0	0.00000	1.00000	100.00
10.5	11,728,030	0	0.00000	1.00000	100.00
11.5	11,728,030	0	0.00000	1.00000	100.00
12.5	11,728,030	0	0.00000	1.00000	100.00
13.5	11,728,030	0	0.00000	1.00000	100.00
14.5	11,728,030	0	0.00000	1.00000	100.00
15.5	11,728,030	0	0.00000	1.00000	100.00
16.5	8,533,214	0	0.00000	1.00000	100.00
17.5	8,533,214	0	0.00000	1.00000	100.00
18.5	7,704,086	0	0.00000	1.00000	100.00
19.5	7,704,086	0	0.00000	1.00000	100.00
20.5	7,704,086	0	0.00000	1.00000	100.00
21.5	7,704,086	0	0.00000	1.00000	100.00
22.5	7,704,086	0	0.00000	1.00000	100.00
23.5	7,704,086	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 53202 - Metal Oxide Varister (Mov)

Placement Band - 2002 - 2016   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 53202 - Metal Oxide Varister (Mov)

Placement Band - 2002 - 2016   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

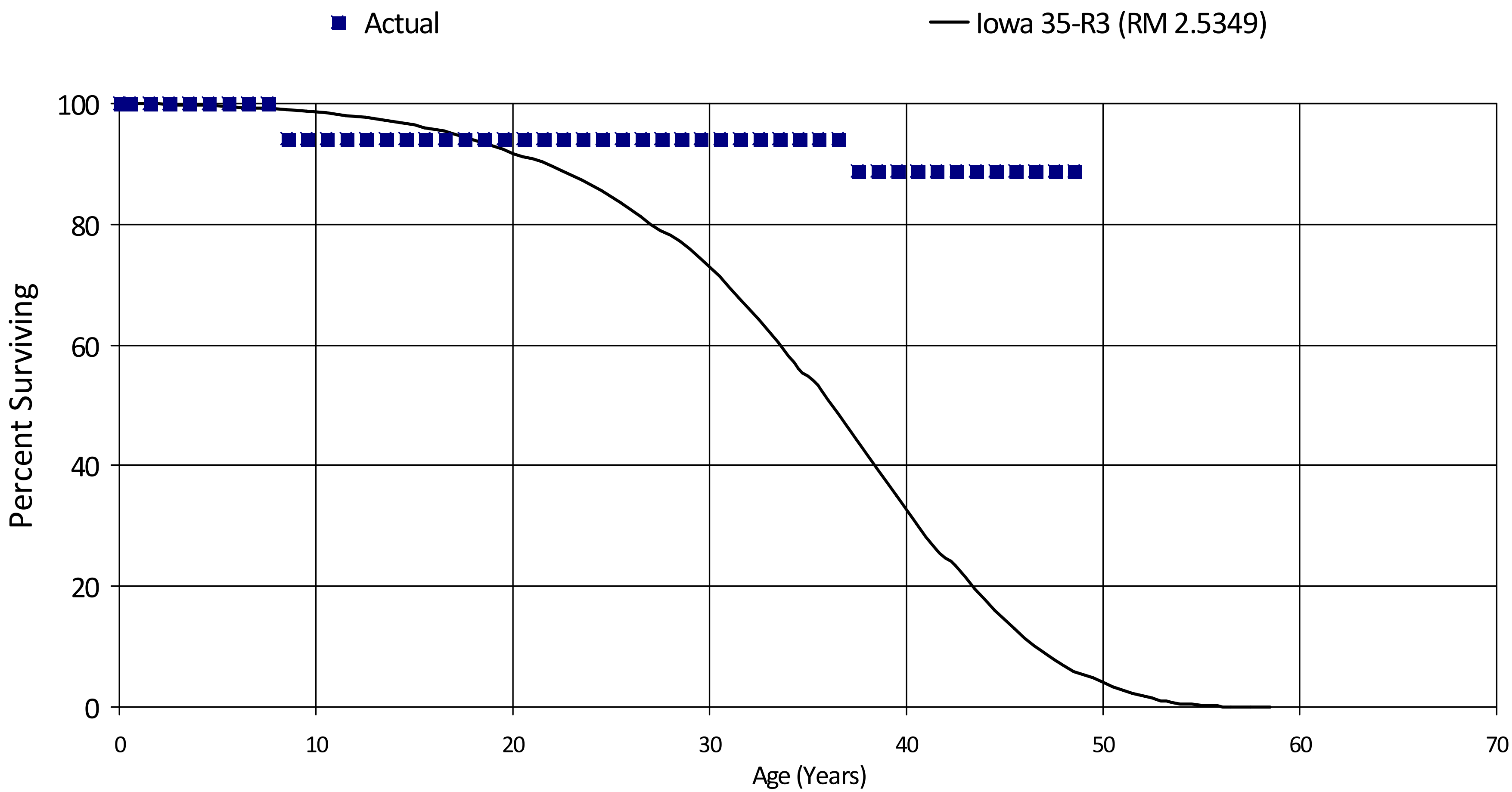
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	13,643,859	0	0.00000	1.00000	100.00
0.5	13,643,859	0	0.00000	1.00000	100.00
1.5	13,643,859	0	0.00000	1.00000	100.00
2.5	13,643,859	0	0.00000	1.00000	100.00
3.5	13,643,859	0	0.00000	1.00000	100.00
4.5	10,264,026	0	0.00000	1.00000	100.00
5.5	10,264,026	0	0.00000	1.00000	100.00
6.5	10,264,026	0	0.00000	1.00000	100.00
7.5	3,707,995	0	0.00000	1.00000	100.00
8.5	3,707,995	0	0.00000	1.00000	100.00
9.5	3,707,995	0	0.00000	1.00000	100.00
10.5	3,707,995	0	0.00000	1.00000	100.00
11.5	3,707,995	0	0.00000	1.00000	100.00
12.5	3,707,995	0	0.00000	1.00000	100.00
13.5	3,707,995	0	0.00000	1.00000	100.00
14.5	3,707,995	0	0.00000	1.00000	100.00
15.5	3,707,995	0	0.00000	1.00000	100.00
16.5	1,009,423	0	0.00000	1.00000	100.00
17.5	1,009,423	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 53301 - Capacitor, Coupling

Placement Band - 1966 - 2017 Experience Band - 2019 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 53301 - Capacitor, Coupling

Placement Band - 1966 - 2017   Experience Band - 2019 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,375,176	0	0.00000	1.00000	100.00
0.5	1,375,176	0	0.00000	1.00000	100.00
1.5	1,375,176	0	0.00000	1.00000	100.00
2.5	1,375,176	0	0.00000	1.00000	100.00
3.5	1,108,438	0	0.00000	1.00000	100.00
4.5	1,108,438	0	0.00000	1.00000	100.00
5.5	1,108,438	0	0.00000	1.00000	100.00
6.5	1,077,768	0	0.00000	1.00000	100.00
7.5	1,077,768	62,306	0.05781	0.94219	100.00
8.5	911,137	0	0.00000	1.00000	94.22
9.5	693,058	0	0.00000	1.00000	94.22
10.5	612,597	0	0.00000	1.00000	94.22
11.5	367,589	0	0.00000	1.00000	94.22
12.5	359,175	0	0.00000	1.00000	94.22
13.5	216,063	0	0.00000	1.00000	94.22
14.5	181,826	0	0.00000	1.00000	94.22
15.5	124,409	0	0.00000	1.00000	94.22
16.5	124,409	0	0.00000	1.00000	94.22
17.5	101,109	0	0.00000	1.00000	94.22
18.5	79,874	0	0.00000	1.00000	94.22
19.5	78,717	0	0.00000	1.00000	94.22
20.5	78,717	0	0.00000	1.00000	94.22
21.5	63,032	0	0.00000	1.00000	94.22
22.5	49,105	0	0.00000	1.00000	94.22
23.5	49,105	0	0.00000	1.00000	94.22
24.5	49,105	0	0.00000	1.00000	94.22
25.5	49,105	0	0.00000	1.00000	94.22
26.5	34,974	0	0.00000	1.00000	94.22

BC Hydro Power Authority

Account 53301 - Capacitor, Coupling

Placement Band - 1966 - 2017 Experience Band - 2019 - 2020

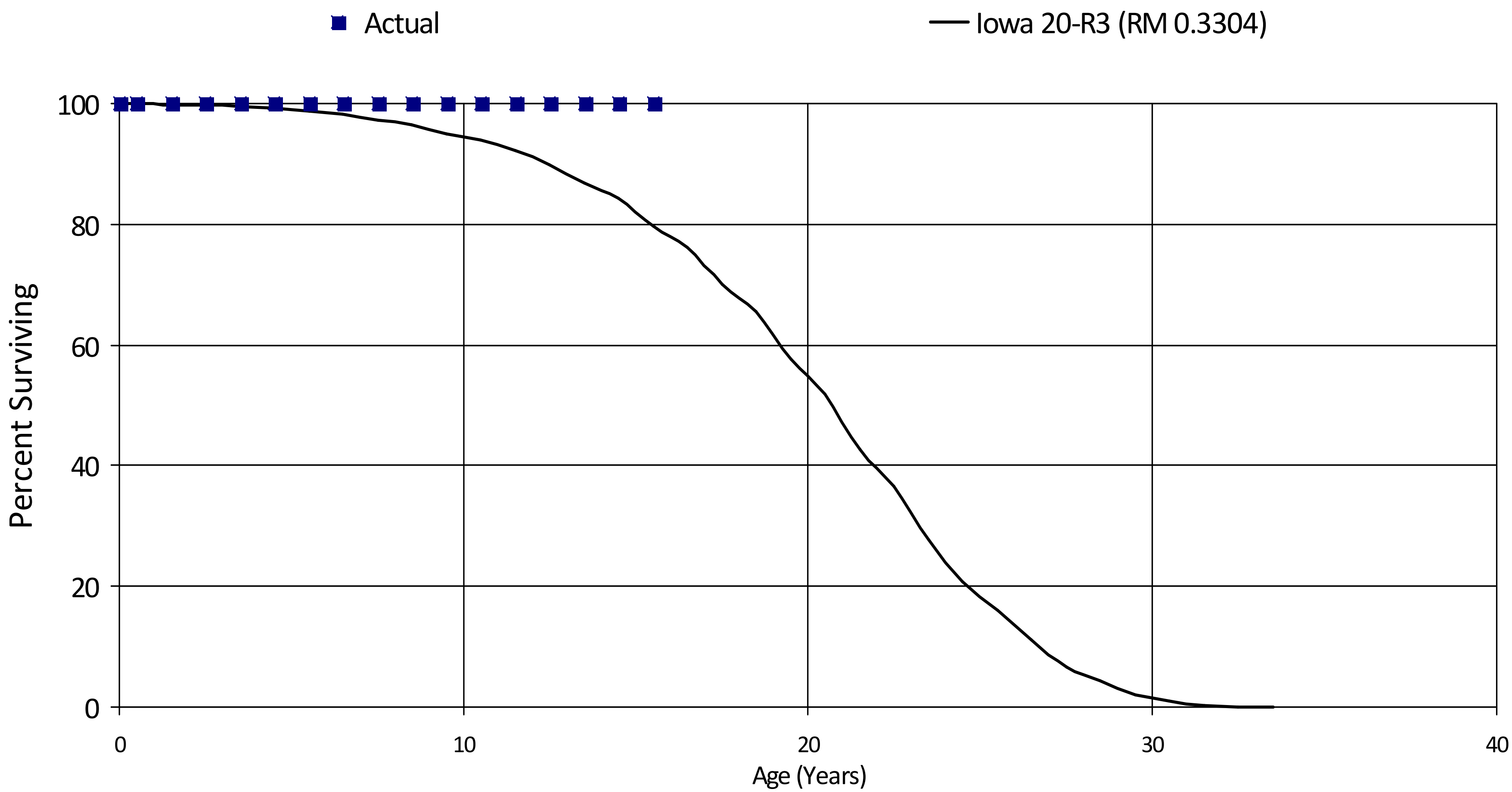
27.5	34,974	0	0.00000	1.00000	94.22
28.5	34,974	0	0.00000	1.00000	94.22
29.5	34,974	0	0.00000	1.00000	94.22
30.5	34,974	0	0.00000	1.00000	94.22
31.5	34,974	0	0.00000	1.00000	94.22
32.5	31,372	0	0.00000	1.00000	94.22
33.5	31,372	0	0.00000	1.00000	94.22
34.5	31,372	0	0.00000	1.00000	94.22
35.5	30,633	0	0.00000	1.00000	94.22
36.5	30,322	1,752	0.05778	0.94222	94.22
37.5	28,570	0	0.00000	1.00000	88.78
38.5	28,570	0	0.00000	1.00000	88.78
39.5	28,570	0	0.00000	1.00000	88.78
40.5	28,570	0	0.00000	1.00000	88.78
41.5	28,570	0	0.00000	1.00000	88.78
42.5	28,570	0	0.00000	1.00000	88.78
43.5	28,570	0	0.00000	1.00000	88.78
44.5	28,570	0	0.00000	1.00000	88.78
45.5	28,570	0	0.00000	1.00000	88.78
46.5	28,570	0	0.00000	1.00000	88.78
47.5	28,570	0	0.00000	1.00000	88.78
48.5	28,570	0	0.00000	1.00000	88.78
	Totals:	64,058			

BC Hydro Power Authority

Account 54101 - Breaker, Air / Magnetic

Placement Band - 1965 - 2020   Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 54101 - Breaker, Air / Magnetic

Placement Band - 1965 - 2020   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

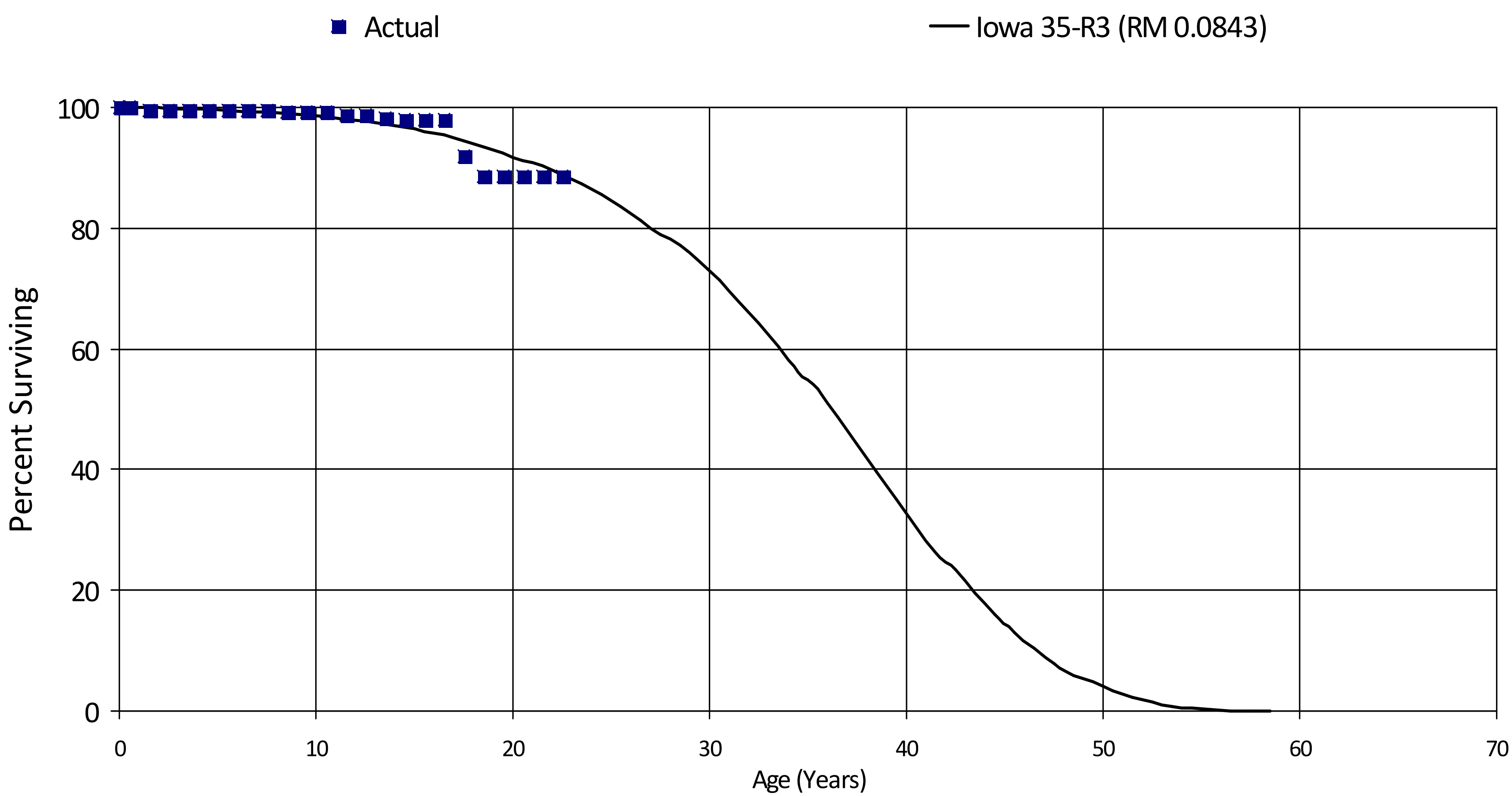
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	24,560,734	0	0.00000	1.00000	100.00
0.5	24,553,984	0	0.00000	1.00000	100.00
1.5	24,524,494	0	0.00000	1.00000	100.00
2.5	20,153,922	0	0.00000	1.00000	100.00
3.5	20,153,922	0	0.00000	1.00000	100.00
4.5	18,865,592	0	0.00000	1.00000	100.00
5.5	18,488,452	0	0.00000	1.00000	100.00
6.5	18,127,508	0	0.00000	1.00000	100.00
7.5	18,127,508	0	0.00000	1.00000	100.00
8.5	8,783,829	0	0.00000	1.00000	100.00
9.5	8,783,829	0	0.00000	1.00000	100.00
10.5	587,128	0	0.00000	1.00000	100.00
11.5	587,128	0	0.00000	1.00000	100.00
12.5	587,128	0	0.00000	1.00000	100.00
13.5	587,128	0	0.00000	1.00000	100.00
14.5	484,300	0	0.00000	1.00000	100.00
15.5	263,497	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 54102 - Breaker, Gas (Sf6) 12 / 25 Kv

Placement Band - 1974 - 2019   Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 54102 - Breaker, Gas (Sf6) 12 / 25 Kv

Placement Band - 1974 - 2019   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

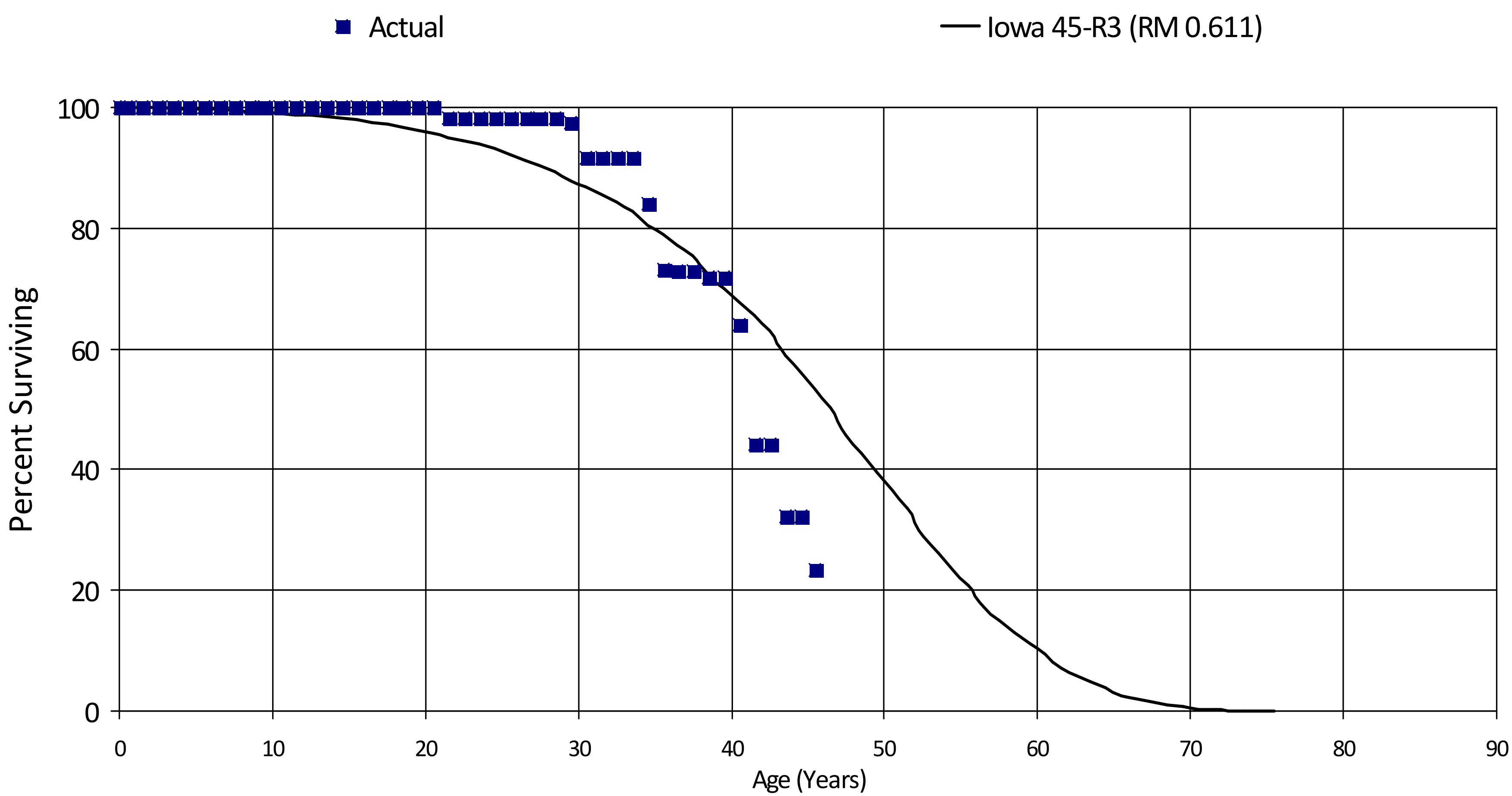
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	183,886,364	0	0.00000	1.00000	100.00
0.5	183,886,364	759,858	0.00413	0.99587	100.00
1.5	173,793,082	0	0.00000	1.00000	99.59
2.5	164,064,440	0	0.00000	1.00000	99.59
3.5	147,583,667	0	0.00000	1.00000	99.59
4.5	116,882,944	4	0.00000	1.00000	99.59
5.5	84,338,972	0	0.00000	1.00000	99.59
6.5	60,334,448	0	0.00000	1.00000	99.59
7.5	47,302,751	166,082	0.00351	0.99649	99.59
8.5	36,283,385	14,359	0.00040	0.99960	99.24
9.5	30,888,464	0	0.00000	1.00000	99.20
10.5	24,760,906	127,507	0.00515	0.99485	99.20
11.5	19,203,441	0	0.00000	1.00000	98.69
12.5	14,242,629	54,731	0.00384	0.99616	98.69
13.5	11,213,740	37,958	0.00338	0.99662	98.31
14.5	7,560,803	0	0.00000	1.00000	97.98
15.5	7,165,771	0	0.00000	1.00000	97.98
16.5	5,989,523	376,832	0.06292	0.93708	97.98
17.5	4,126,732	141,481	0.03428	0.96572	91.82
18.5	3,252,617	0	0.00000	1.00000	88.67
19.5	3,144,432	0	0.00000	1.00000	88.67
20.5	2,880,749	0	0.00000	1.00000	88.67
21.5	2,651,283	0	0.00000	1.00000	88.67
22.5	2,074,456	72,343	0.03487	0.96513	88.67
	Totals:	1,751,155			

BC Hydro Power Authority

Account 54103 - Breaker, Bulk / Min Oil / Air Blast

Placement Band - 1939 - 2017 Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 54103 - Breaker, Bulk / Min Oil / Air Blast

Placement Band - 1939 - 2017   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	24,404,191	0	0.00000	1.00000	100.00
0.5	24,404,191	0	0.00000	1.00000	100.00
1.5	24,404,191	0	0.00000	1.00000	100.00
2.5	24,404,191	0	0.00000	1.00000	100.00
3.5	16,829,102	0	0.00000	1.00000	100.00
4.5	16,829,102	0	0.00000	1.00000	100.00
5.5	14,555,083	0	0.00000	1.00000	100.00
6.5	7,552,594	0	0.00000	1.00000	100.00
7.5	7,503,720	0	0.00000	1.00000	100.00
8.5	6,851,545	0	0.00000	1.00000	100.00
9.5	6,851,545	0	0.00000	1.00000	100.00
10.5	6,395,360	0	0.00000	1.00000	100.00
11.5	6,395,360	0	0.00000	1.00000	100.00
12.5	6,315,874	0	0.00000	1.00000	100.00
13.5	6,315,874	0	0.00000	1.00000	100.00
14.5	4,760,947	0	0.00000	1.00000	100.00
15.5	4,760,947	0	0.00000	1.00000	100.00
16.5	4,078,490	855	0.00021	0.99979	100.00
17.5	4,020,836	0	0.00000	1.00000	99.98
18.5	3,966,322	0	0.00000	1.00000	99.98
19.5	3,966,322	0	0.00000	1.00000	99.98
20.5	3,924,194	69,536	0.01772	0.98228	99.98
21.5	3,854,657	0	0.00000	1.00000	98.21
22.5	3,783,021	0	0.00000	1.00000	98.21
23.5	3,671,730	0	0.00000	1.00000	98.21
24.5	3,556,823	0	0.00000	1.00000	98.21
25.5	3,556,823	0	0.00000	1.00000	98.21
26.5	3,380,392	0	0.00000	1.00000	98.21

BC Hydro Power Authority

Account 54103 - Breaker, Bulk / Min Oil / Air Blast

Placement Band - 1939 - 2017 Experience Band - 2011 - 2020

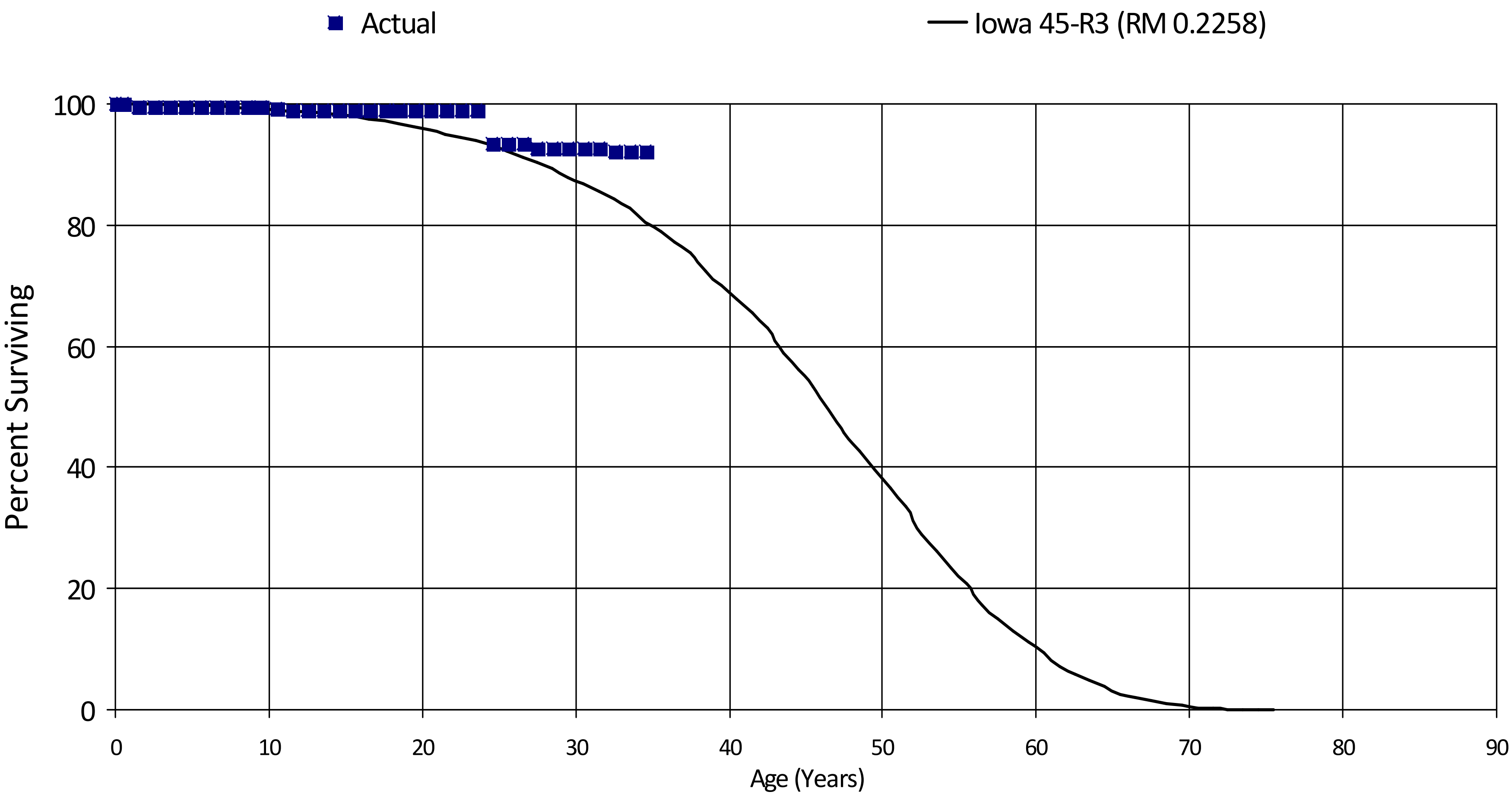
27.5	3,347,552	0	0.00000	1.00000	98.21
28.5	3,145,751	20,307	0.00646	0.99354	98.21
29.5	3,125,444	191,807	0.06137	0.93863	97.58
30.5	2,933,637	0	0.00000	1.00000	91.59
31.5	2,925,827	0	0.00000	1.00000	91.59
32.5	2,925,827	0	0.00000	1.00000	91.59
33.5	2,873,235	235,986	0.08213	0.91787	91.59
34.5	2,637,249	344,746	0.13072	0.86928	84.07
35.5	1,951,134	7,412	0.00380	0.99620	73.08
36.5	1,929,307	0	0.00000	1.00000	72.80
37.5	1,917,882	26,951	0.01405	0.98595	72.80
38.5	1,889,510	0	0.00000	1.00000	71.78
39.5	1,871,187	202,162	0.10804	0.89196	71.78
40.5	1,662,178	514,608	0.30960	0.69040	64.02
41.5	1,145,949	0	0.00000	1.00000	44.20
42.5	1,140,670	309,357	0.27121	0.72879	44.20
43.5	823,021	0	0.00000	1.00000	32.21
44.5	823,021	225,884	0.27446	0.72554	32.21
45.5	450,792	265,738	0.58949	0.41051	23.37
	Totals:	2,415,349			

BC Hydro Power Authority

Account 54104 - Breaker, Gas (Sf6), 69 To 500 Kv

Placement Band - 1974 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 54104 - Breaker, Gas (Sf6), 69 To 500 Kv

Placement Band - 1974 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	451,341,556	0	0.00000	1.00000	100.00
0.5	450,646,965	1,989,361	0.00441	0.99559	100.00
1.5	433,856,703	0	0.00000	1.00000	99.56
2.5	409,356,455	0	0.00000	1.00000	99.56
3.5	365,494,842	0	0.00000	1.00000	99.56
4.5	310,910,190	0	0.00000	1.00000	99.56
5.5	259,118,428	0	0.00000	1.00000	99.56
6.5	228,697,249	0	0.00000	1.00000	99.56
7.5	198,121,769	0	0.00000	1.00000	99.56
8.5	174,624,499	0	0.00000	1.00000	99.56
9.5	142,649,817	318,932	0.00224	0.99776	99.56
10.5	103,214,089	391,878	0.00380	0.99620	99.34
11.5	89,140,820	0	0.00000	1.00000	98.96
12.5	73,877,995	0	0.00000	1.00000	98.96
13.5	62,358,448	0	0.00000	1.00000	98.96
14.5	50,213,607	0	0.00000	1.00000	98.96
15.5	43,114,054	0	0.00000	1.00000	98.96
16.5	28,990,731	0	0.00000	1.00000	98.96
17.5	23,424,126	0	0.00000	1.00000	98.96
18.5	22,301,811	0	0.00000	1.00000	98.96
19.5	20,529,323	0	0.00000	1.00000	98.96
20.5	18,389,263	0	0.00000	1.00000	98.96
21.5	17,629,836	0	0.00000	1.00000	98.96
22.5	17,102,531	0	0.00000	1.00000	98.96
23.5	16,737,435	946,770	0.05657	0.94343	98.96
24.5	12,081,803	0	0.00000	1.00000	93.36
25.5	9,375,171	0	0.00000	1.00000	93.36
26.5	8,165,540	73,888	0.00905	0.99095	93.36

BC Hydro Power Authority

Account 54104 - Breaker, Gas (Sf6), 69 To 500 Kv

Placement Band - 1974 - 2020 Experience Band - 2013 - 2020

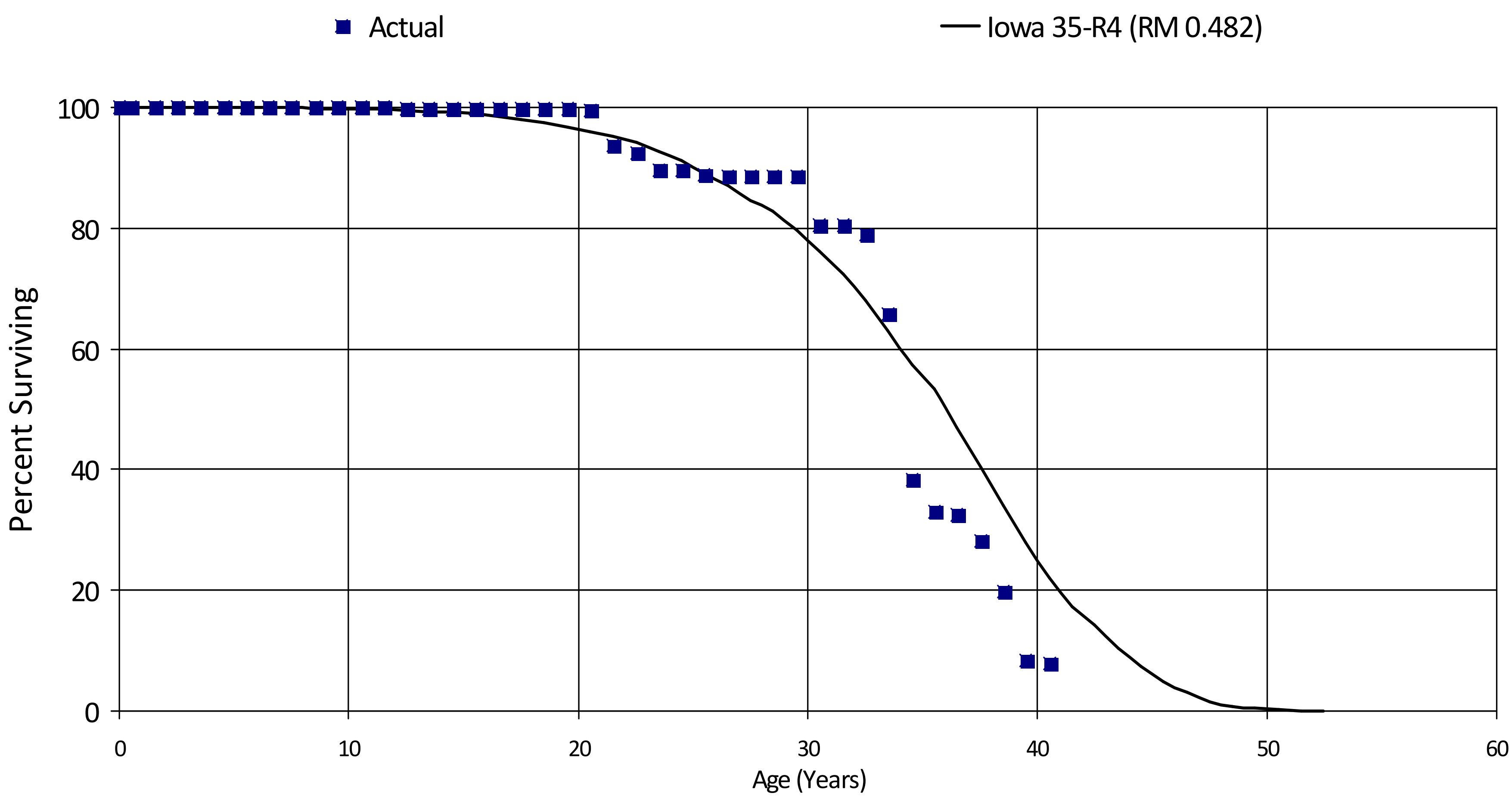
27.5	7,109,967	0	0.00000	1.00000	92.52
28.5	7,109,967	0	0.00000	1.00000	92.52
29.5	7,109,967	0	0.00000	1.00000	92.52
30.5	7,089,704	0	0.00000	1.00000	92.52
31.5	6,840,048	22,155	0.00324	0.99676	92.52
32.5	6,815,697	0	0.00000	1.00000	92.22
33.5	6,490,114	0	0.00000	1.00000	92.22
34.5	6,490,114	0	0.00000	1.00000	92.22
	Totals:	3,742,984			

BC Hydro Power Authority

Account 54105 - Breakers, Composite Pool

Placement Band - 1939 - 2019   Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 54105 - Breakers, Composite Pool

Placement Band - 1939 - 2019   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	24,462,340	0	0.00000	1.00000	100.00
0.5	24,462,340	0	0.00000	1.00000	100.00
1.5	24,395,569	0	0.00000	1.00000	100.00
2.5	24,395,569	0	0.00000	1.00000	100.00
3.5	24,395,569	0	0.00000	1.00000	100.00
4.5	24,395,569	0	0.00000	1.00000	100.00
5.5	24,323,626	0	0.00000	1.00000	100.00
6.5	24,323,626	0	0.00000	1.00000	100.00
7.5	23,577,658	0	0.00000	1.00000	100.00
8.5	13,391,564	0	0.00000	1.00000	100.00
9.5	10,247,708	0	0.00000	1.00000	100.00
10.5	10,247,708	0	0.00000	1.00000	100.00
11.5	10,247,708	18,543	0.00181	0.99819	100.00
12.5	10,197,079	0	0.00000	1.00000	99.82
13.5	10,163,217	0	0.00000	1.00000	99.82
14.5	10,163,217	0	0.00000	1.00000	99.82
15.5	10,156,536	0	0.00000	1.00000	99.82
16.5	10,146,479	0	0.00000	1.00000	99.82
17.5	10,101,188	0	0.00000	1.00000	99.82
18.5	10,099,132	0	0.00000	1.00000	99.82
19.5	10,099,132	41,115	0.00407	0.99593	99.82
20.5	10,058,017	594,367	0.05909	0.94091	99.41
21.5	9,463,650	105,176	0.01111	0.98889	93.54
22.5	9,358,474	289,043	0.03089	0.96911	92.50
23.5	9,069,430	0	0.00000	1.00000	89.64
24.5	9,036,926	77,408	0.00857	0.99143	89.64
25.5	8,959,518	26,085	0.00291	0.99709	88.87
26.5	8,923,907	0	0.00000	1.00000	88.61

BC Hydro Power Authority

Account 54105 - Breakers, Composite Pool

Placement Band - 1939 - 2019   Experience Band - 2011 - 2020

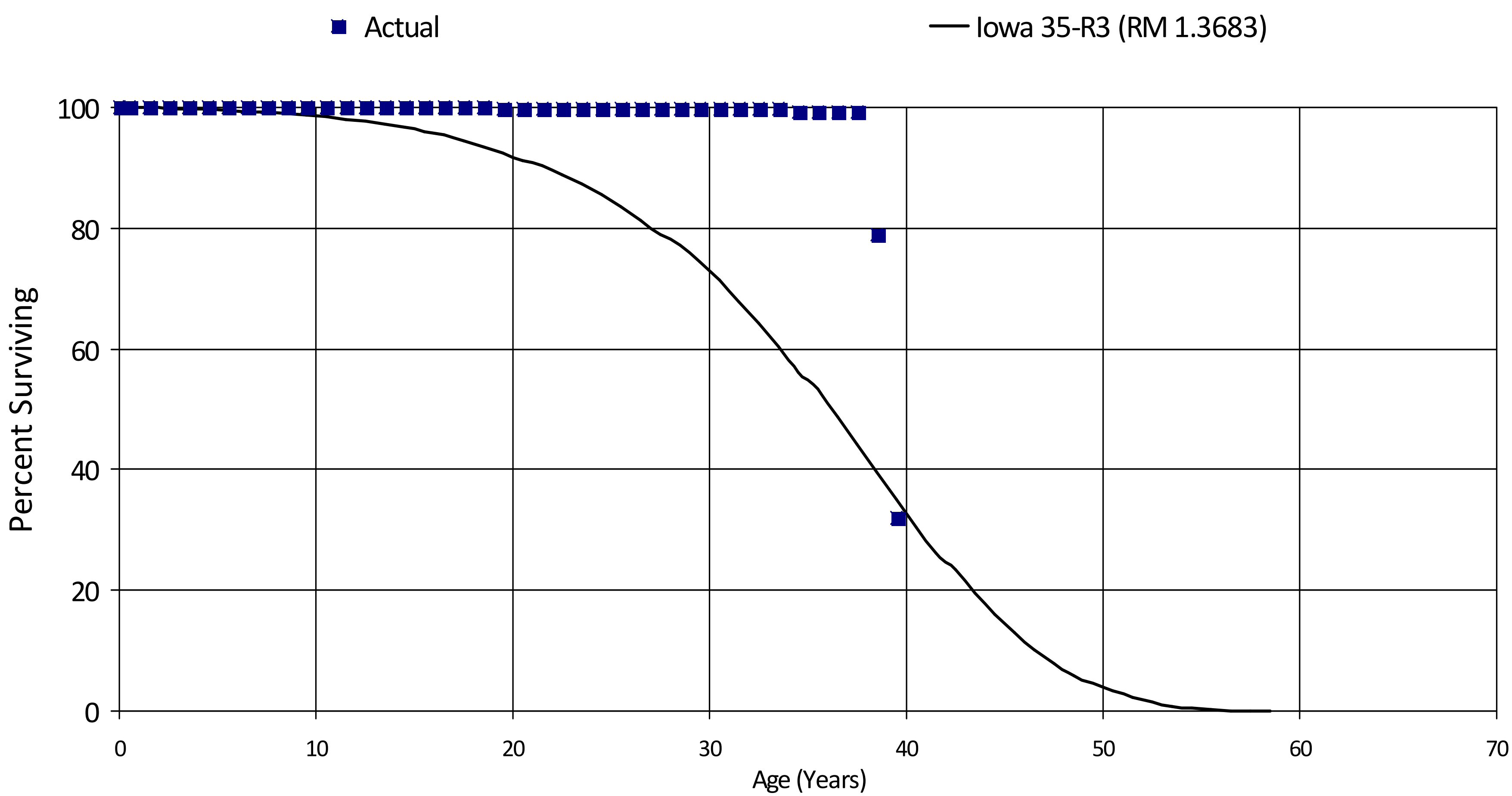
27.5	8,921,697	0	0.00000	1.00000	88.61
28.5	8,332,150	2,883	0.00035	0.99965	88.61
29.5	8,057,672	742,559	0.09216	0.90784	88.58
30.5	6,570,934	0	0.00000	1.00000	80.42
31.5	5,828,100	101,146	0.01735	0.98265	80.42
32.5	5,558,448	938,960	0.16892	0.83108	79.02
33.5	4,554,579	1,895,838	0.41625	0.58375	65.67
34.5	2,607,003	365,930	0.14036	0.85964	38.33
35.5	2,184,969	29,377	0.01345	0.98655	32.95
36.5	2,145,213	293,851	0.13698	0.86302	32.51
37.5	1,813,913	527,197	0.29064	0.70936	28.06
38.5	1,229,180	717,548	0.58376	0.41624	19.90
39.5	511,632	32,305	0.06314	0.93686	8.28
40.5	479,327	346,603	0.72310	0.27690	7.76
	Totals:	7,145,934			

BC Hydro Power Authority

Account 54201 - Use Individual Disconnect Caus

Placement Band - 1971 - 2012 Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 54201 - Use Individual Disconnect Caus

Placement Band - 1971 - 2012   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	27,588,374	0	0.00000	1.00000	100.00
0.5	27,588,374	0	0.00000	1.00000	100.00
1.5	27,588,374	0	0.00000	1.00000	100.00
2.5	27,588,374	0	0.00000	1.00000	100.00
3.5	27,588,374	0	0.00000	1.00000	100.00
4.5	27,588,374	0	0.00000	1.00000	100.00
5.5	27,588,374	0	0.00000	1.00000	100.00
6.5	27,588,374	0	0.00000	1.00000	100.00
7.5	27,588,374	0	0.00000	1.00000	100.00
8.5	27,303,692	0	0.00000	1.00000	100.00
9.5	27,303,692	0	0.00000	1.00000	100.00
10.5	27,303,692	0	0.00000	1.00000	100.00
11.5	27,303,692	0	0.00000	1.00000	100.00
12.5	27,280,408	0	0.00000	1.00000	100.00
13.5	27,280,408	0	0.00000	1.00000	100.00
14.5	27,213,670	0	0.00000	1.00000	100.00
15.5	27,213,670	0	0.00000	1.00000	100.00
16.5	27,160,442	0	0.00000	1.00000	100.00
17.5	27,021,936	0	0.00000	1.00000	100.00
18.5	26,570,877	85,504	0.00322	0.99678	100.00
19.5	26,408,361	0	0.00000	1.00000	99.68
20.5	26,378,990	0	0.00000	1.00000	99.68
21.5	26,210,459	0	0.00000	1.00000	99.68
22.5	25,944,446	0	0.00000	1.00000	99.68
23.5	25,032,181	7,591	0.00030	0.99970	99.68
24.5	22,488,273	0	0.00000	1.00000	99.65
25.5	21,227,566	0	0.00000	1.00000	99.65
26.5	19,128,123	0	0.00000	1.00000	99.65

BC Hydro Power Authority

Account 54201 - Use Individual Disconnect Caus

Placement Band - 1971 - 2012 Experience Band - 2011 - 2020

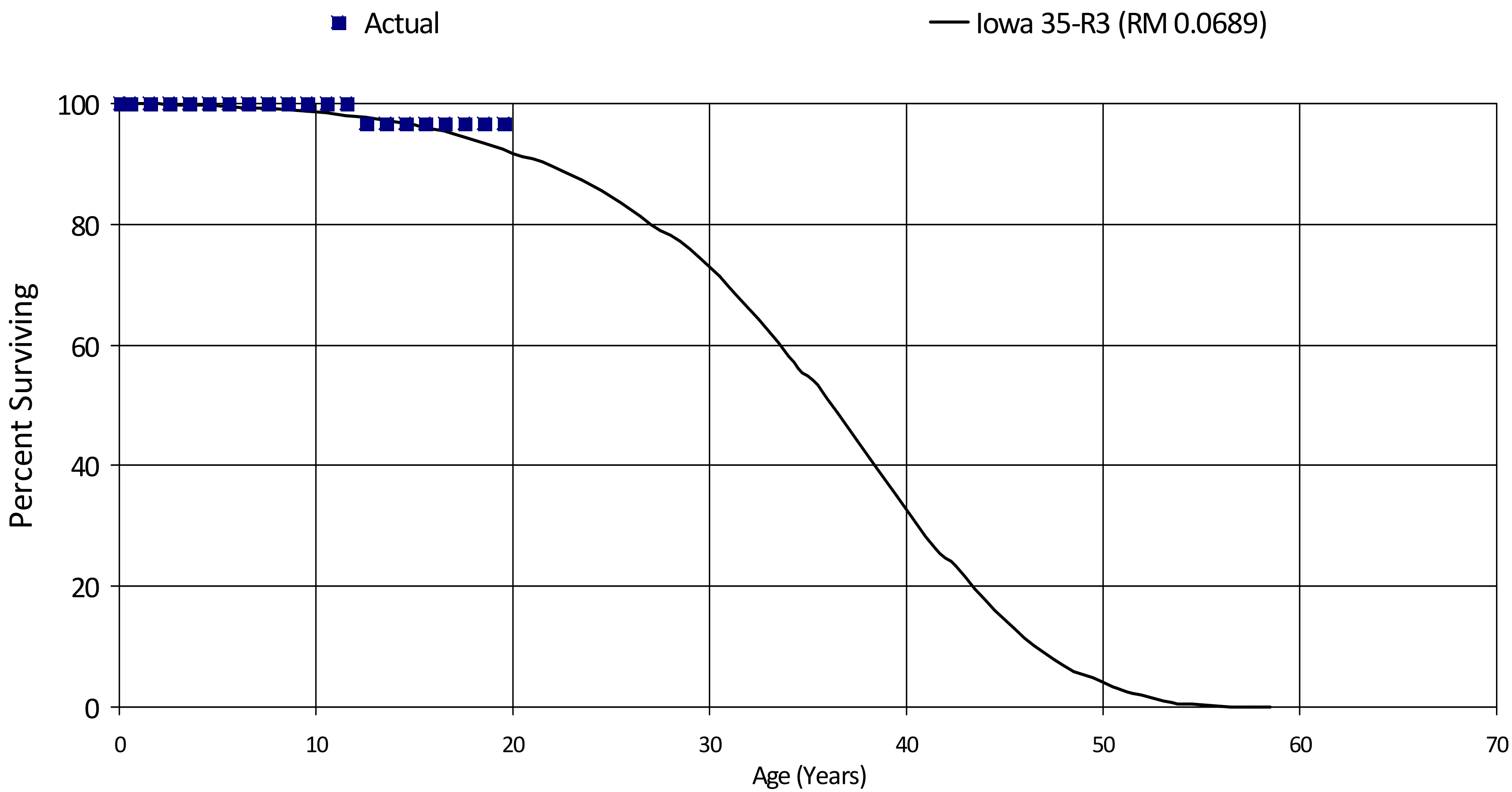
27.5	19,091,750	0	0.00000	1.00000	99.65
28.5	18,958,409	0	0.00000	1.00000	99.65
29.5	17,880,324	0	0.00000	1.00000	99.65
30.5	17,059,862	0	0.00000	1.00000	99.65
31.5	16,388,967	0	0.00000	1.00000	99.65
32.5	15,584,416	0	0.00000	1.00000	99.65
33.5	15,453,065	45,288	0.00293	0.99707	99.65
34.5	15,175,250	749	0.00005	0.99995	99.36
35.5	11,708,802	14,271	0.00122	0.99878	99.36
36.5	10,286,670	8,070	0.00078	0.99922	99.24
37.5	9,560,518	1,954,306	0.20441	0.79559	99.16
38.5	6,712,683	3,986,170	0.59383	0.40617	78.89
39.5	2,323,853	436,103	0.18766	0.81234	32.04
	Totals:	6,538,052			

BC Hydro Power Authority

Account 54202 - Disconnect, 1 Phase, Hookstick

Placement Band - 1968 - 2019   Experience Band - 2018 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 54202 - Disconnect, 1 Phase, Hookstick

Placement Band - 1968 - 2019   Experience Band - 2018 - 2020

RETIREMENT RATE ANALYSIS

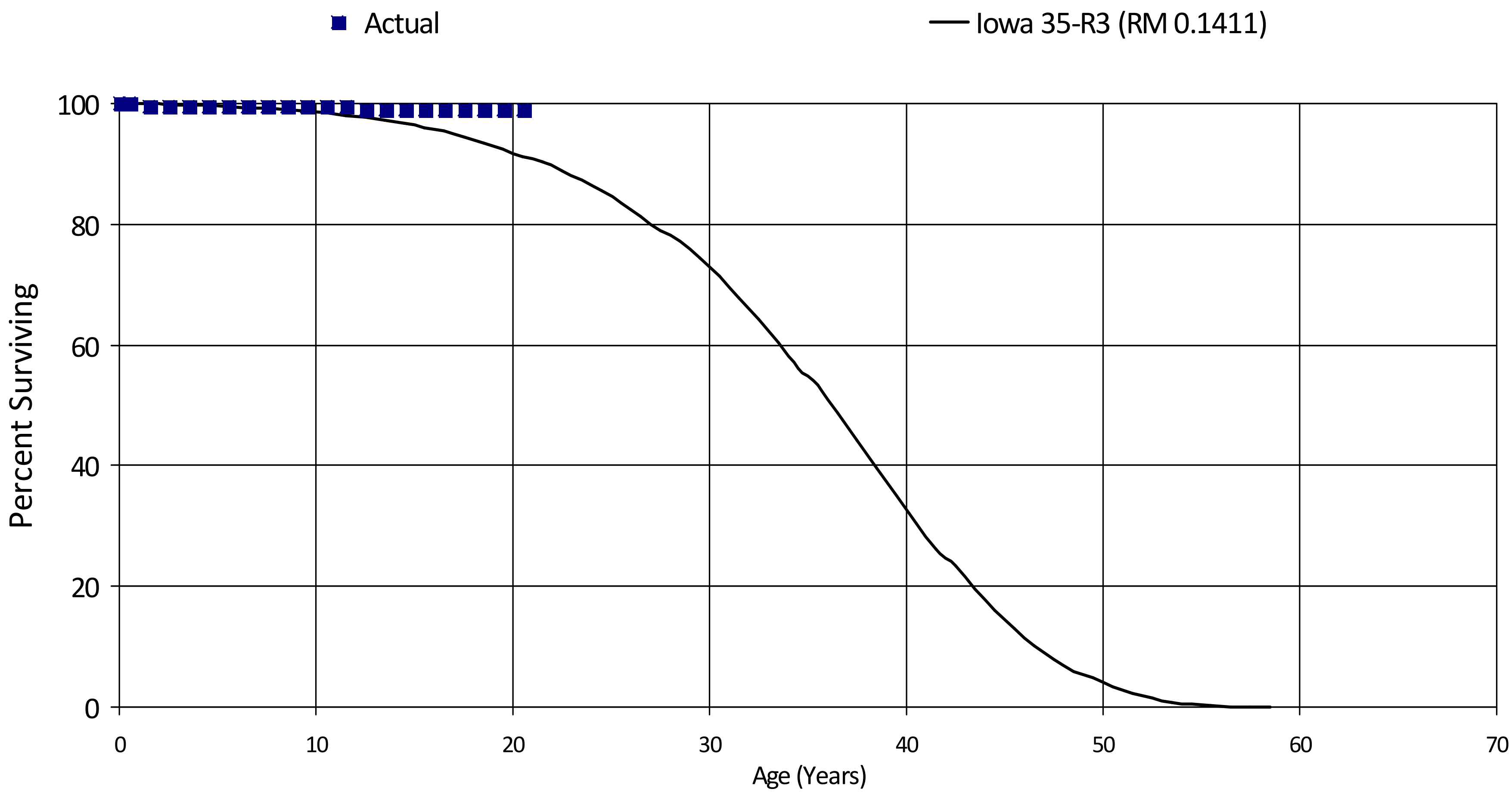
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,853,750	0	0.00000	1.00000	100.00
0.5	1,853,750	0	0.00000	1.00000	100.00
1.5	1,724,826	0	0.00000	1.00000	100.00
2.5	1,724,826	0	0.00000	1.00000	100.00
3.5	1,709,490	0	0.00000	1.00000	100.00
4.5	1,709,490	0	0.00000	1.00000	100.00
5.5	1,709,490	0	0.00000	1.00000	100.00
6.5	1,687,886	0	0.00000	1.00000	100.00
7.5	1,635,900	0	0.00000	1.00000	100.00
8.5	1,105,163	0	0.00000	1.00000	100.00
9.5	920,457	0	0.00000	1.00000	100.00
10.5	607,201	0	0.00000	1.00000	100.00
11.5	553,148	18,141	0.03280	0.96720	100.00
12.5	275,007	0	0.00000	1.00000	96.72
13.5	254,879	0	0.00000	1.00000	96.72
14.5	64,991	0	0.00000	1.00000	96.72
15.5	64,991	0	0.00000	1.00000	96.72
16.5	64,991	0	0.00000	1.00000	96.72
17.5	40,881	0	0.00000	1.00000	96.72
18.5	40,881	0	0.00000	1.00000	96.72
19.5	39,463	0	0.00000	1.00000	96.72
	Totals:	18,141			

BC Hydro Power Authority

Account 54203 - Disconnect, 3 Phase, 12 / 25Kv

Placement Band - 1997 - 2019   Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 54203 - Disconnect, 3 Phase, 12 / 25Kv

Placement Band - 1997 - 2019   Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

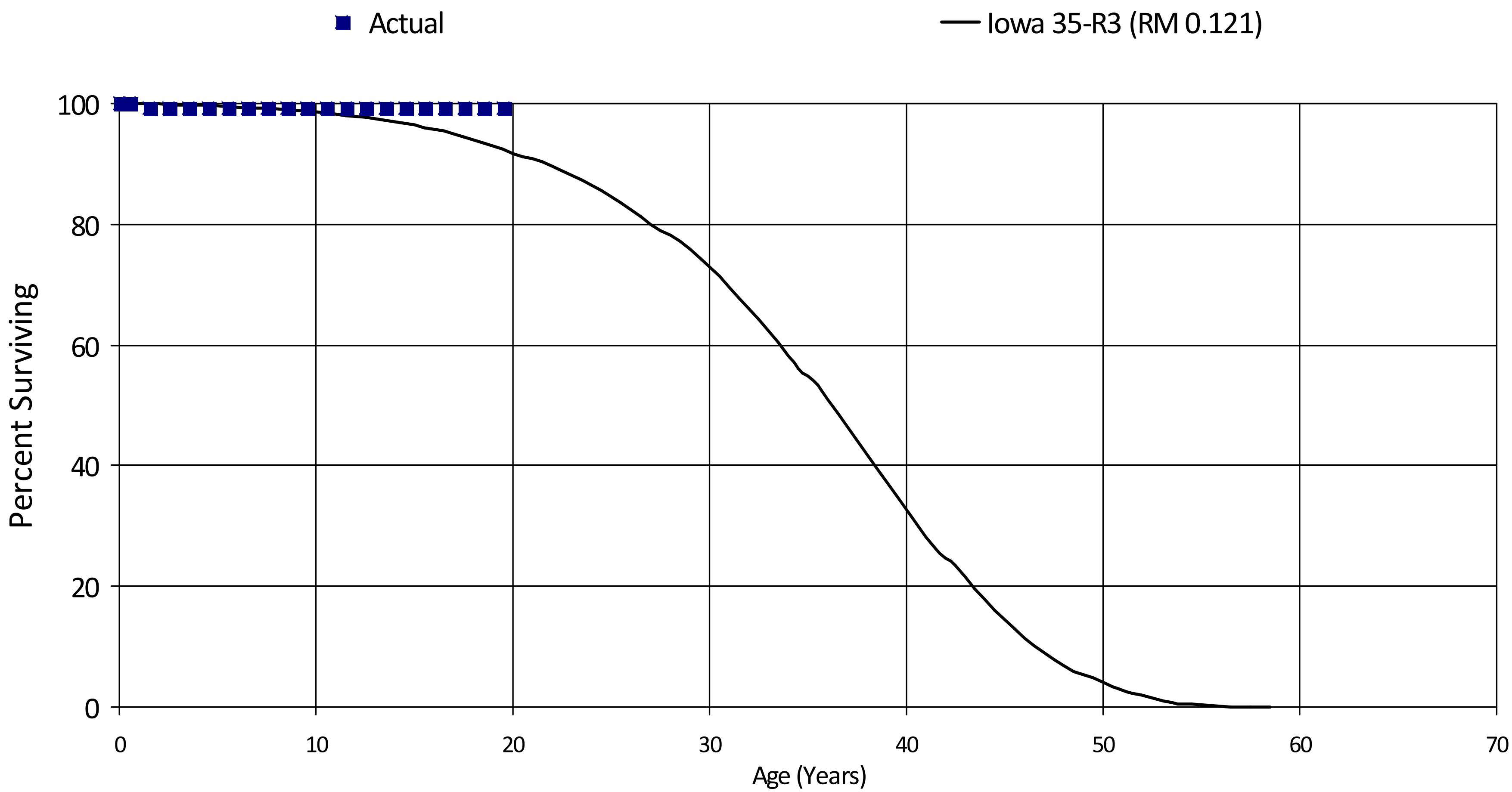
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	61,893,980	0	0.00000	1.00000	100.00
0.5	61,893,980	353,278	0.00571	0.99429	100.00
1.5	52,641,741	0	0.00000	1.00000	99.43
2.5	44,808,364	0	0.00000	1.00000	99.43
3.5	33,538,906	0	0.00000	1.00000	99.43
4.5	28,250,695	0	0.00000	1.00000	99.43
5.5	25,555,027	0	0.00000	1.00000	99.43
6.5	22,132,875	0	0.00000	1.00000	99.43
7.5	18,284,708	0	0.00000	1.00000	99.43
8.5	16,510,265	0	0.00000	1.00000	99.43
9.5	15,699,445	0	0.00000	1.00000	99.43
10.5	13,528,402	0	0.00000	1.00000	99.43
11.5	10,835,933	35,628	0.00329	0.99671	99.43
12.5	7,532,236	0	0.00000	1.00000	99.10
13.5	5,367,900	0	0.00000	1.00000	99.10
14.5	3,881,611	0	0.00000	1.00000	99.10
15.5	3,592,004	0	0.00000	1.00000	99.10
16.5	2,496,959	0	0.00000	1.00000	99.10
17.5	1,684,708	0	0.00000	1.00000	99.10
18.5	1,174,798	0	0.00000	1.00000	99.10
19.5	988,549	0	0.00000	1.00000	99.10
20.5	894,811	0	0.00000	1.00000	99.10
	Totals:	388,906			

BC Hydro Power Authority

Account 54204 - Disconnect, 3 Phase, 69-230Kv

Placement Band - 1968 - 2020   Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 54204 - Disconnect, 3 Phase, 69-230Kv

Placement Band - 1968 - 2020   Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

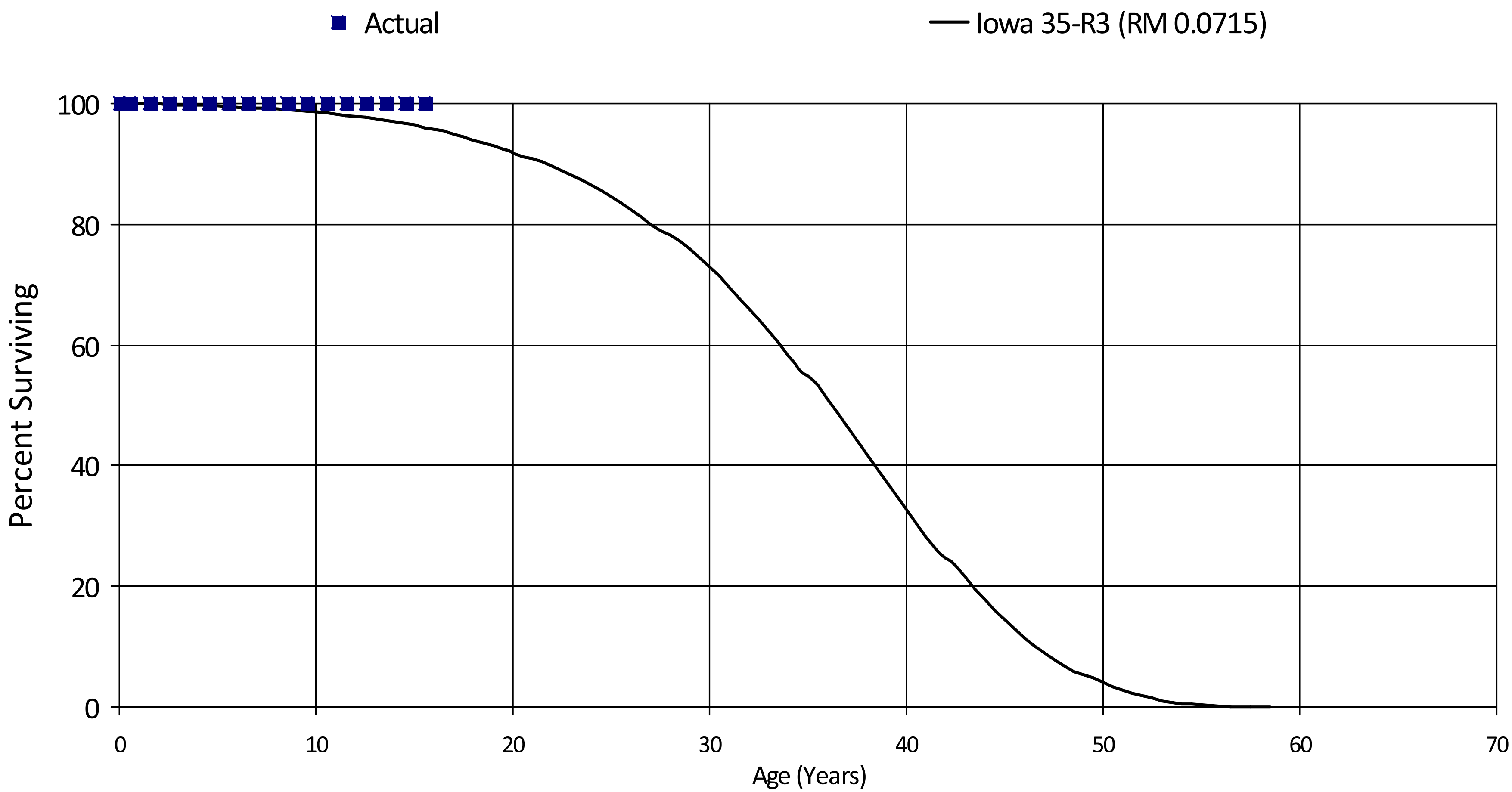
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	94,543,047	0	0.00000	1.00000	100.00
0.5	91,997,340	682,880	0.00742	0.99258	100.00
1.5	88,809,446	0	0.00000	1.00000	99.26
2.5	85,256,198	0	0.00000	1.00000	99.26
3.5	75,983,666	0	0.00000	1.00000	99.26
4.5	53,261,241	0	0.00000	1.00000	99.26
5.5	43,627,361	0	0.00000	1.00000	99.26
6.5	30,009,321	0	0.00000	1.00000	99.26
7.5	21,350,224	0	0.00000	1.00000	99.26
8.5	17,706,757	0	0.00000	1.00000	99.26
9.5	14,074,877	0	0.00000	1.00000	99.26
10.5	10,976,283	0	0.00000	1.00000	99.26
11.5	9,067,775	0	0.00000	1.00000	99.26
12.5	7,319,942	0	0.00000	1.00000	99.26
13.5	5,822,580	0	0.00000	1.00000	99.26
14.5	5,287,026	0	0.00000	1.00000	99.26
15.5	3,727,461	0	0.00000	1.00000	99.26
16.5	2,837,285	0	0.00000	1.00000	99.26
17.5	1,907,774	0	0.00000	1.00000	99.26
18.5	1,538,644	0	0.00000	1.00000	99.26
19.5	1,191,731	0	0.00000	1.00000	99.26
	Totals:	682,880			

BC Hydro Power Authority

Account 54205 - Disconnect, 3 Phase, 500Kv

Placement Band - 2002 - 2019   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 54205 - Disconnect, 3 Phase, 500Kv

Placement Band - 2002 - 2019 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

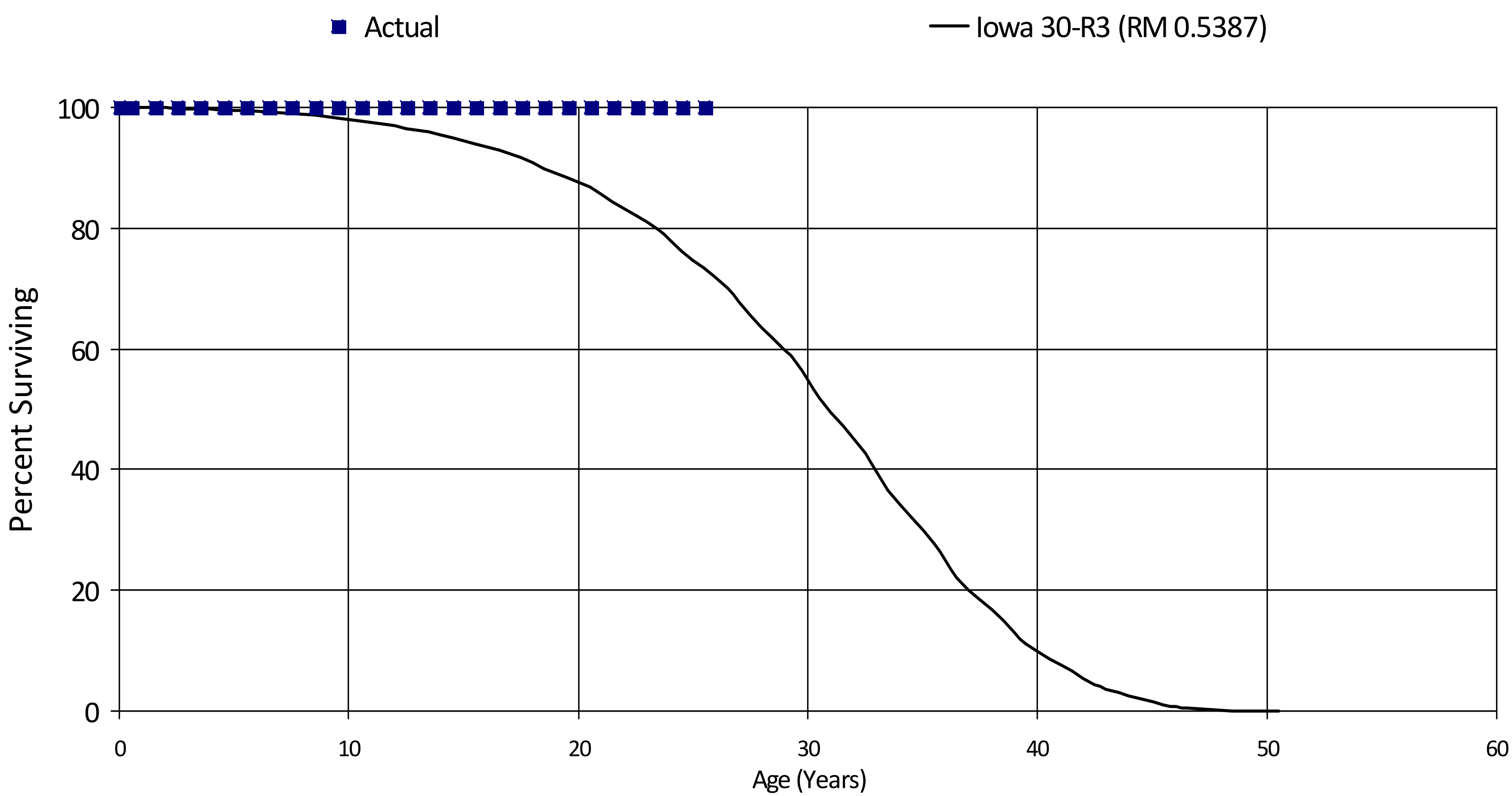
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	71,713,306	0	0.00000	1.00000	100.00
0.5	71,713,306	0	0.00000	1.00000	100.00
1.5	67,930,317	0	0.00000	1.00000	100.00
2.5	67,609,729	0	0.00000	1.00000	100.00
3.5	67,388,194	0	0.00000	1.00000	100.00
4.5	65,478,933	0	0.00000	1.00000	100.00
5.5	53,230,057	0	0.00000	1.00000	100.00
6.5	42,174,705	0	0.00000	1.00000	100.00
7.5	40,012,242	0	0.00000	1.00000	100.00
8.5	2,886,141	0	0.00000	1.00000	100.00
9.5	2,285,222	0	0.00000	1.00000	100.00
10.5	2,029,478	0	0.00000	1.00000	100.00
11.5	2,029,478	0	0.00000	1.00000	100.00
12.5	1,749,963	0	0.00000	1.00000	100.00
13.5	1,743,133	0	0.00000	1.00000	100.00
14.5	1,432,371	0	0.00000	1.00000	100.00
15.5	1,278,793	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 54401 - Switchgear, Metalclad

Placement Band - 1976 - 2020   Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 54401 - Switchgear, Metalclad

Placement Band - 1976 - 2020   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

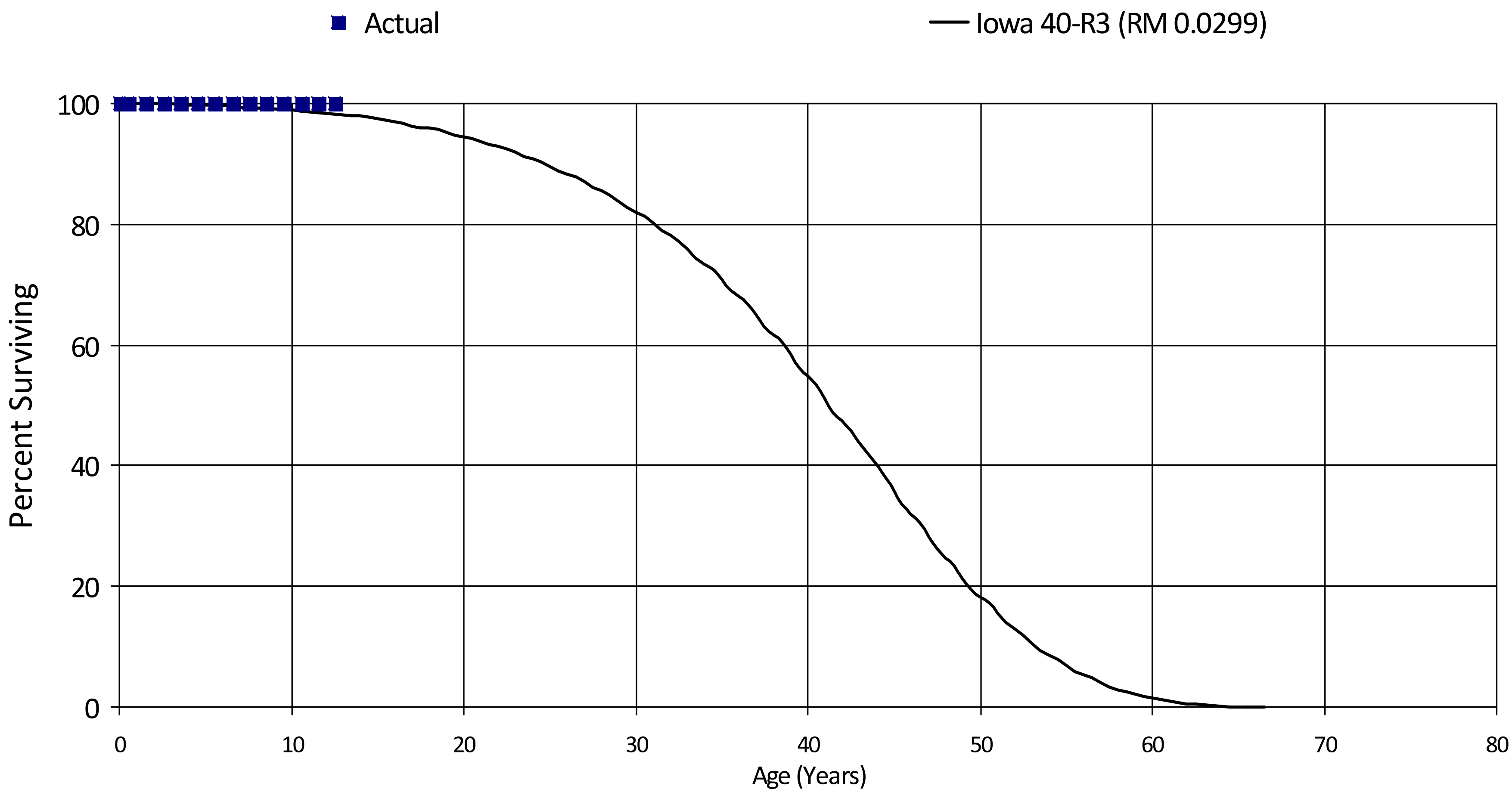
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	71,469,804	0	0.00000	1.00000	100.00
0.5	71,065,672	0	0.00000	1.00000	100.00
1.5	54,649,638	0	0.00000	1.00000	100.00
2.5	39,746,955	0	0.00000	1.00000	100.00
3.5	39,394,543	0	0.00000	1.00000	100.00
4.5	32,859,303	0	0.00000	1.00000	100.00
5.5	30,773,495	0	0.00000	1.00000	100.00
6.5	28,635,838	0	0.00000	1.00000	100.00
7.5	24,361,409	0	0.00000	1.00000	100.00
8.5	14,472,771	0	0.00000	1.00000	100.00
9.5	14,472,771	0	0.00000	1.00000	100.00
10.5	9,760,280	0	0.00000	1.00000	100.00
11.5	6,868,487	0	0.00000	1.00000	100.00
12.5	5,897,210	0	0.00000	1.00000	100.00
13.5	5,897,210	1,129	0.00019	0.99981	100.00
14.5	5,883,892	0	0.00000	1.00000	99.98
15.5	3,950,325	0	0.00000	1.00000	99.98
16.5	3,950,325	0	0.00000	1.00000	99.98
17.5	3,078,309	0	0.00000	1.00000	99.98
18.5	3,078,309	0	0.00000	1.00000	99.98
19.5	3,054,417	0	0.00000	1.00000	99.98
20.5	2,618,209	0	0.00000	1.00000	99.98
21.5	2,618,209	0	0.00000	1.00000	99.98
22.5	2,177,262	0	0.00000	1.00000	99.98
23.5	2,177,262	0	0.00000	1.00000	99.98
24.5	1,856,457	0	0.00000	1.00000	99.98
25.5	1,579,040	0	0.00000	1.00000	99.98
	Totals:	1,129			

BC Hydro Power Authority

Account 54501 - Circuit Recloser

Placement Band - 1977 - 2020 Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 54501 - Circuit Recloser

Placement Band - 1977 - 2020   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

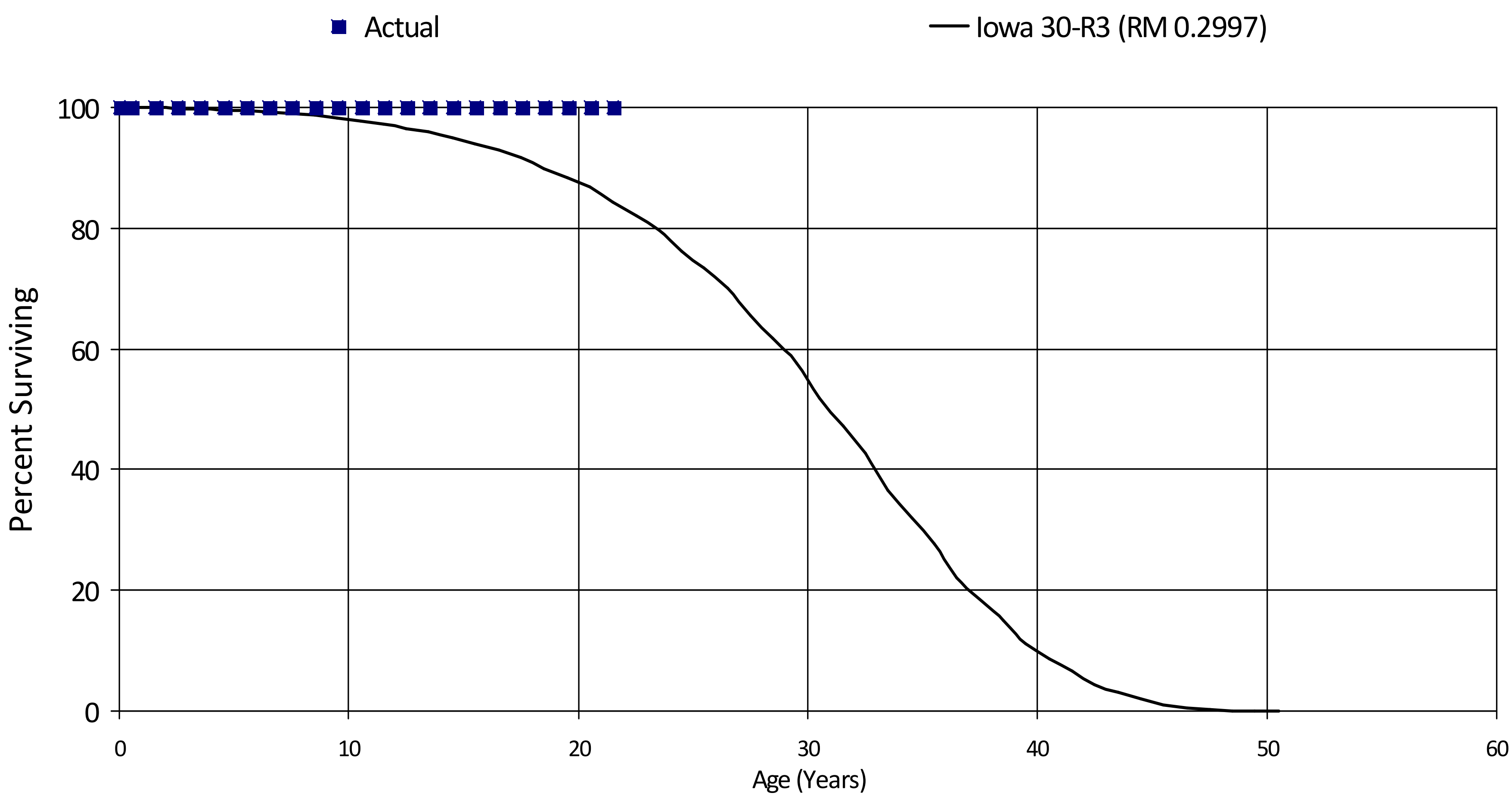
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	97,213,611	0	0.00000	1.00000	100.00
0.5	96,357,273	0	0.00000	1.00000	100.00
1.5	71,742,256	0	0.00000	1.00000	100.00
2.5	57,116,270	0	0.00000	1.00000	100.00
3.5	49,549,580	0	0.00000	1.00000	100.00
4.5	39,439,342	0	0.00000	1.00000	100.00
5.5	33,886,496	0	0.00000	1.00000	100.00
6.5	29,109,268	0	0.00000	1.00000	100.00
7.5	24,000,517	0	0.00000	1.00000	100.00
8.5	15,529,950	0	0.00000	1.00000	100.00
9.5	9,502,404	0	0.00000	1.00000	100.00
10.5	4,048,285	0	0.00000	1.00000	100.00
11.5	2,061,586	0	0.00000	1.00000	100.00
12.5	1,376,465	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 54601 - Circuit Switcher

Placement Band - 1983 - 2018 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 54601 - Circuit Switcher

Placement Band - 1983 - 2018   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

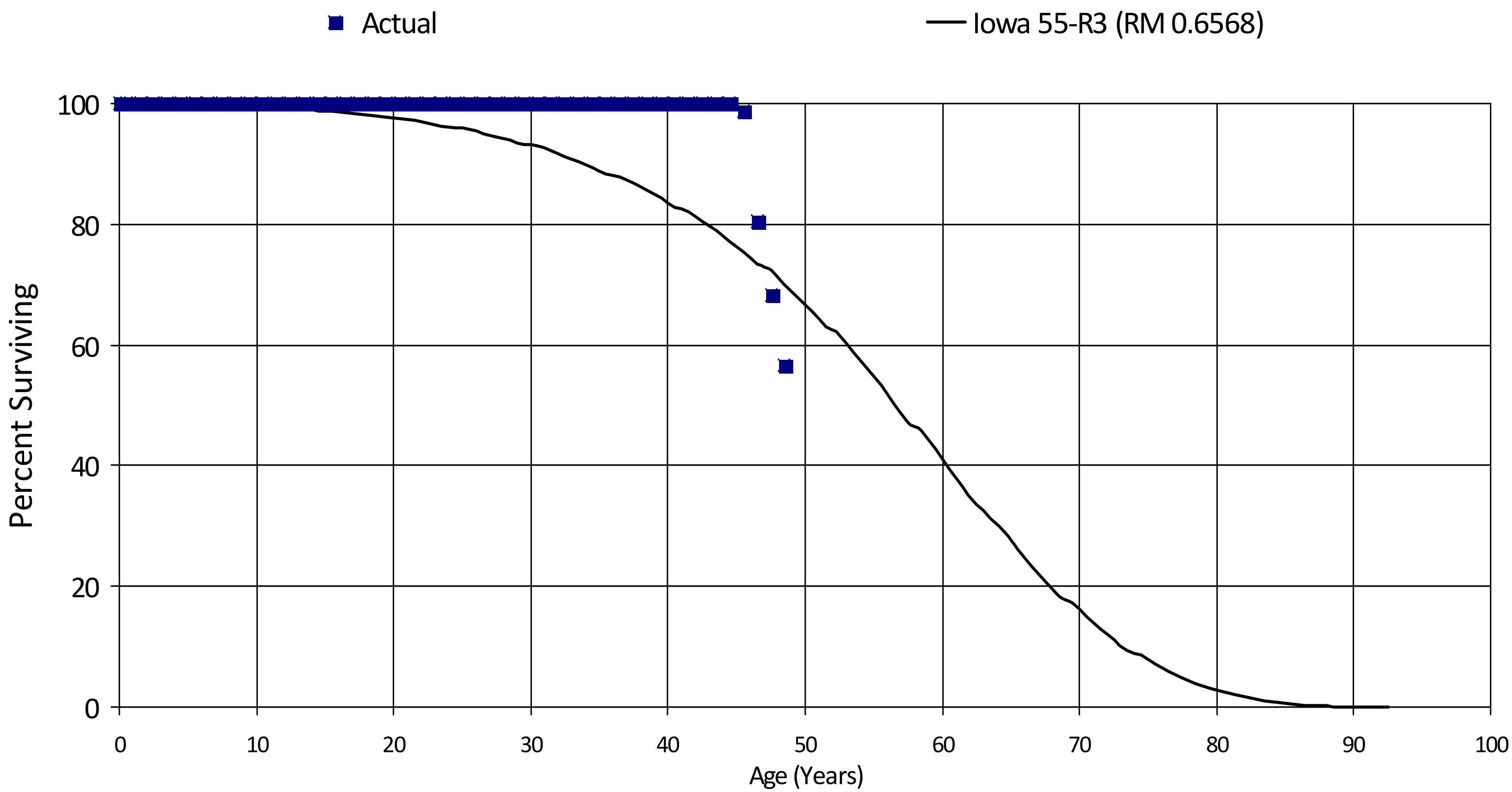
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	9,093,577	0	0.00000	1.00000	100.00
0.5	9,093,577	0	0.00000	1.00000	100.00
1.5	9,093,577	0	0.00000	1.00000	100.00
2.5	8,413,546	0	0.00000	1.00000	100.00
3.5	8,413,546	0	0.00000	1.00000	100.00
4.5	8,413,546	0	0.00000	1.00000	100.00
5.5	8,413,546	0	0.00000	1.00000	100.00
6.5	8,413,546	0	0.00000	1.00000	100.00
7.5	8,405,408	0	0.00000	1.00000	100.00
8.5	4,278,420	0	0.00000	1.00000	100.00
9.5	1,893,395	0	0.00000	1.00000	100.00
10.5	777,500	0	0.00000	1.00000	100.00
11.5	777,500	0	0.00000	1.00000	100.00
12.5	684,218	0	0.00000	1.00000	100.00
13.5	684,218	0	0.00000	1.00000	100.00
14.5	644,324	0	0.00000	1.00000	100.00
15.5	644,324	0	0.00000	1.00000	100.00
16.5	615,673	0	0.00000	1.00000	100.00
17.5	542,415	0	0.00000	1.00000	100.00
18.5	197,597	0	0.00000	1.00000	100.00
19.5	96,093	0	0.00000	1.00000	100.00
20.5	96,093	0	0.00000	1.00000	100.00
21.5	92,421	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 55101 - Conductor, Overhead > 60 Kv

Placement Band - 1957 - 2020 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 55101 - Conductor, Overhead > 60 Kv

Placement Band - 1957 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	763,364,434	0	0.00000	1.00000	100.00
0.5	763,141,531	0	0.00000	1.00000	100.00
1.5	755,530,408	0	0.00000	1.00000	100.00
2.5	733,438,528	0	0.00000	1.00000	100.00
3.5	711,948,145	0	0.00000	1.00000	100.00
4.5	515,734,314	0	0.00000	1.00000	100.00
5.5	468,643,278	0	0.00000	1.00000	100.00
6.5	324,050,979	0	0.00000	1.00000	100.00
7.5	282,929,406	0	0.00000	1.00000	100.00
8.5	274,598,868	0	0.00000	1.00000	100.00
9.5	265,068,471	0	0.00000	1.00000	100.00
10.5	258,339,690	0	0.00000	1.00000	100.00
11.5	249,715,968	0	0.00000	1.00000	100.00
12.5	226,163,922	0	0.00000	1.00000	100.00
13.5	224,801,504	0	0.00000	1.00000	100.00
14.5	218,848,969	0	0.00000	1.00000	100.00
15.5	217,191,972	0	0.00000	1.00000	100.00
16.5	215,576,826	0	0.00000	1.00000	100.00
17.5	210,662,029	0	0.00000	1.00000	100.00
18.5	209,962,647	0	0.00000	1.00000	100.00
19.5	208,462,244	0	0.00000	1.00000	100.00
20.5	207,797,056	0	0.00000	1.00000	100.00
21.5	206,627,489	0	0.00000	1.00000	100.00
22.5	205,462,052	0	0.00000	1.00000	100.00
23.5	204,491,303	0	0.00000	1.00000	100.00
24.5	202,064,051	0	0.00000	1.00000	100.00
25.5	178,502,696	0	0.00000	1.00000	100.00
26.5	175,324,227	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 55101 - Conductor, Overhead > 60 Kv

Placement Band - 1957 - 2020 Experience Band - 2013 - 2020

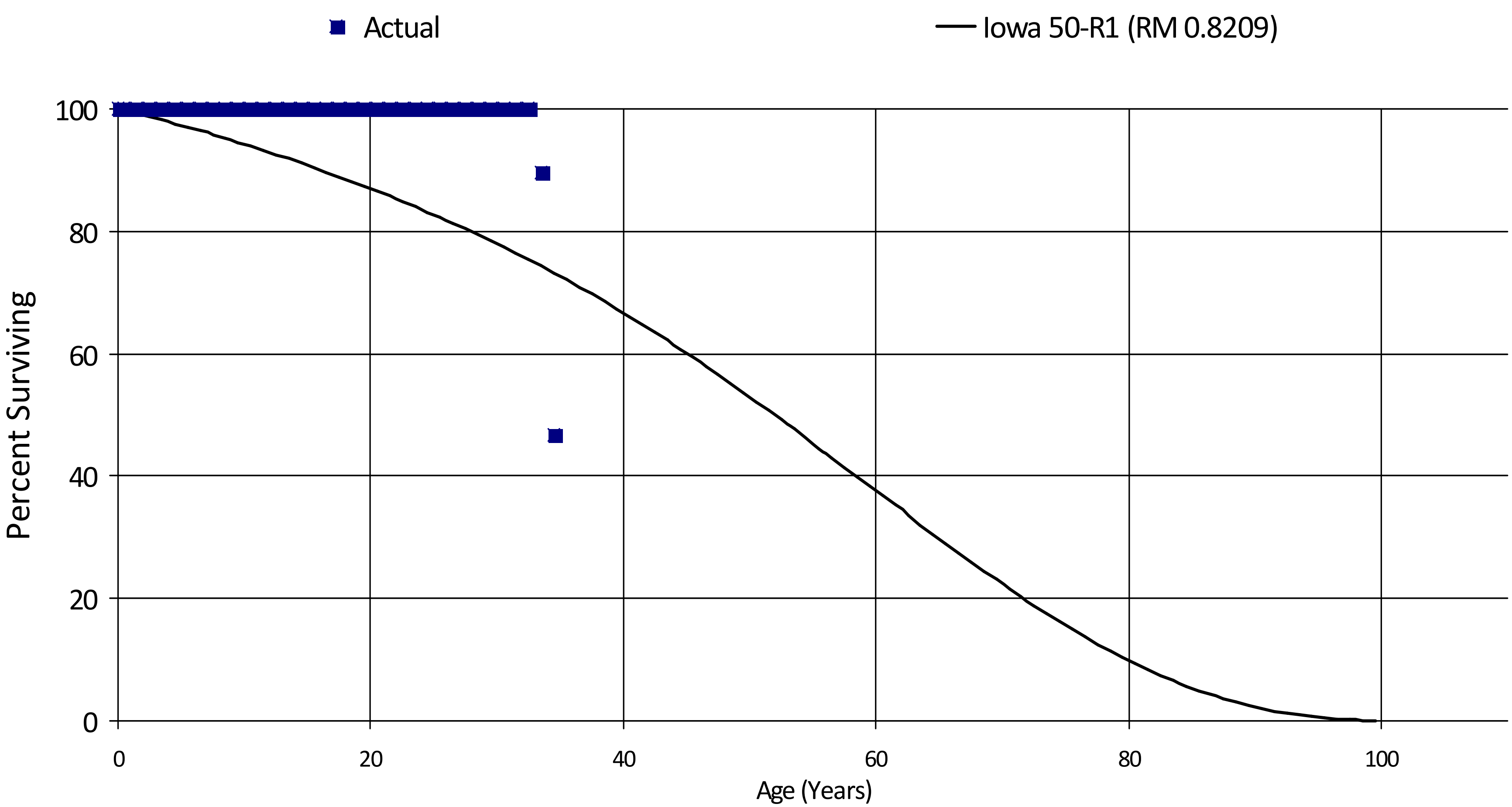
27.5	173,719,007	0	0.00000	1.00000	100.00
28.5	169,753,476	0	0.00000	1.00000	100.00
29.5	168,163,837	0	0.00000	1.00000	100.00
30.5	162,205,838	0	0.00000	1.00000	100.00
31.5	160,782,878	0	0.00000	1.00000	100.00
32.5	160,422,409	0	0.00000	1.00000	100.00
33.5	155,666,102	0	0.00000	1.00000	100.00
34.5	140,155,340	0	0.00000	1.00000	100.00
35.5	121,199,760	0	0.00000	1.00000	100.00
36.5	102,055,958	0	0.00000	1.00000	100.00
37.5	88,909,043	0	0.00000	1.00000	100.00
38.5	75,578,863	0	0.00000	1.00000	100.00
39.5	71,560,165	0	0.00000	1.00000	100.00
40.5	54,160,229	0	0.00000	1.00000	100.00
41.5	46,119,527	0	0.00000	1.00000	100.00
42.5	43,430,892	0	0.00000	1.00000	100.00
43.5	23,744,983	0	0.00000	1.00000	100.00
44.5	20,596,576	279,237	0.01356	0.98644	100.00
45.5	18,781,103	3,476,687	0.18512	0.81488	98.64
46.5	14,981,542	2,234,206	0.14913	0.85087	80.38
47.5	11,974,924	2,056,874	0.17177	0.82823	68.39
48.5	8,690,745	2,933,170	0.33751	0.66249	56.64
	Totals:	10,980,174			

BC Hydro Power Authority

Account 55102 - Conductor, Overhead < 60 Kv

Placement Band - 1966 - 2020 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 55102 - Conductor, Overhead < 60 Kv

Placement Band - 1966 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	827,347,457	0	0.00000	1.00000	100.00
0.5	819,336,788	0	0.00000	1.00000	100.00
1.5	780,950,815	0	0.00000	1.00000	100.00
2.5	738,870,174	0	0.00000	1.00000	100.00
3.5	692,578,210	0	0.00000	1.00000	100.00
4.5	653,191,652	0	0.00000	1.00000	100.00
5.5	605,246,394	0	0.00000	1.00000	100.00
6.5	562,128,370	0	0.00000	1.00000	100.00
7.5	534,984,682	0	0.00000	1.00000	100.00
8.5	485,174,485	0	0.00000	1.00000	100.00
9.5	439,544,435	0	0.00000	1.00000	100.00
10.5	397,752,318	0	0.00000	1.00000	100.00
11.5	354,134,745	0	0.00000	1.00000	100.00
12.5	301,130,162	0	0.00000	1.00000	100.00
13.5	272,198,664	0	0.00000	1.00000	100.00
14.5	252,149,439	0	0.00000	1.00000	100.00
15.5	233,948,058	0	0.00000	1.00000	100.00
16.5	219,241,250	0	0.00000	1.00000	100.00
17.5	186,896,637	0	0.00000	1.00000	100.00
18.5	173,464,703	0	0.00000	1.00000	100.00
19.5	161,191,037	0	0.00000	1.00000	100.00
20.5	151,447,086	0	0.00000	1.00000	100.00
21.5	142,221,097	0	0.00000	1.00000	100.00
22.5	130,344,332	0	0.00000	1.00000	100.00
23.5	116,584,726	0	0.00000	1.00000	100.00
24.5	100,837,182	0	0.00000	1.00000	100.00
25.5	88,243,809	0	0.00000	1.00000	100.00
26.5	73,300,851	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 55102 - Conductor, Overhead < 60 Kv

Placement Band - 1966 - 2020 Experience Band - 2013 - 2020

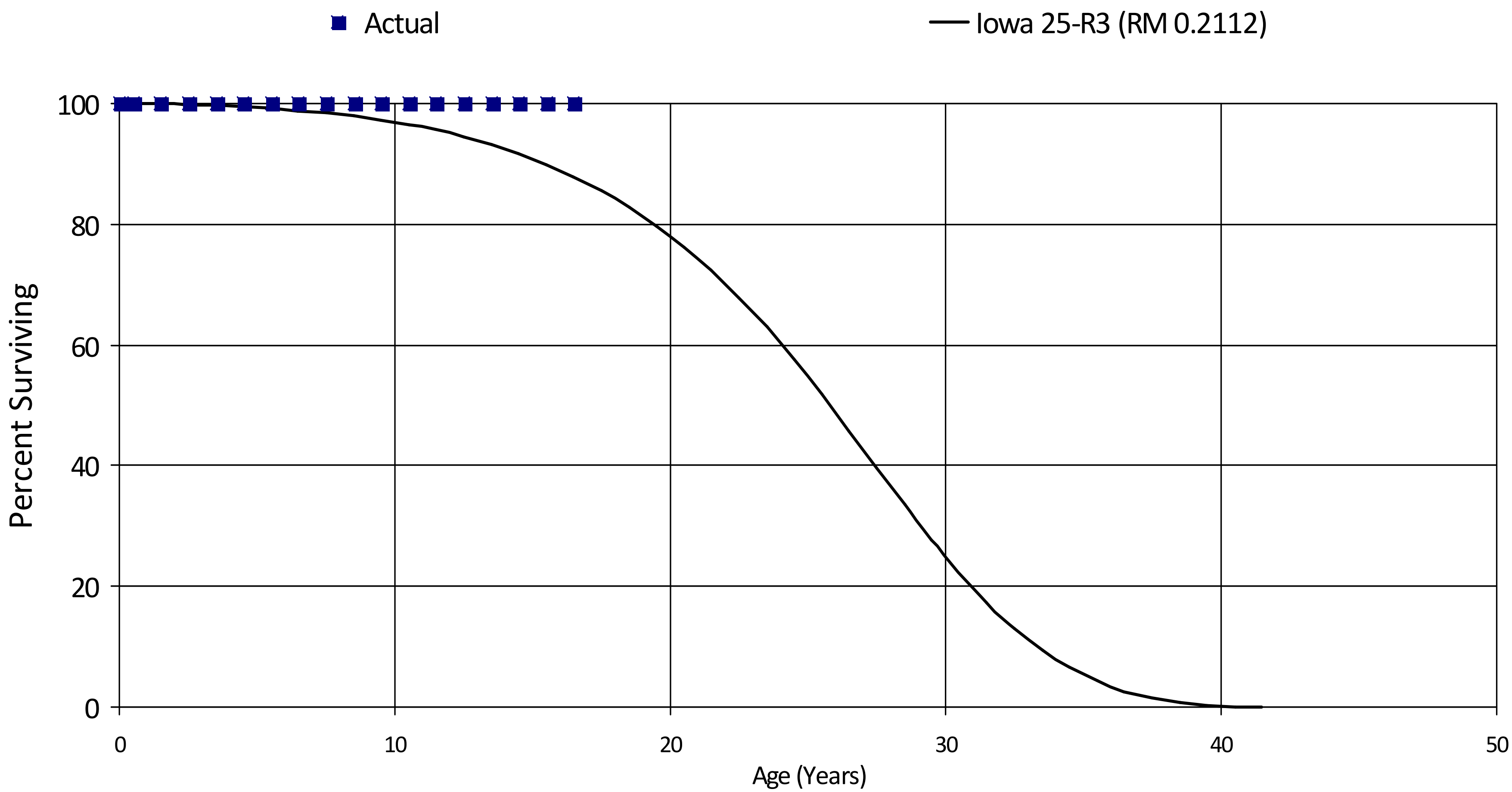
27.5	66,085,393	0	0.00000	1.00000	100.00
28.5	57,516,295	0	0.00000	1.00000	100.00
29.5	53,105,799	0	0.00000	1.00000	100.00
30.5	50,099,937	0	0.00000	1.00000	100.00
31.5	49,092,923	0	0.00000	1.00000	100.00
32.5	45,349,968	4,771,904	0.10522	0.89478	100.00
33.5	40,545,983	19,431,686	0.47925	0.52075	89.48
34.5	21,114,298	13,581,246	0.64323	0.35677	46.60
	Totals:	37,784,836			

BC Hydro Power Authority

Account 55103 - Line Disconnect Switches

Placement Band - 1990 - 2019 Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 55103 - Line Disconnect Switches

Placement Band - 1990 - 2019 Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

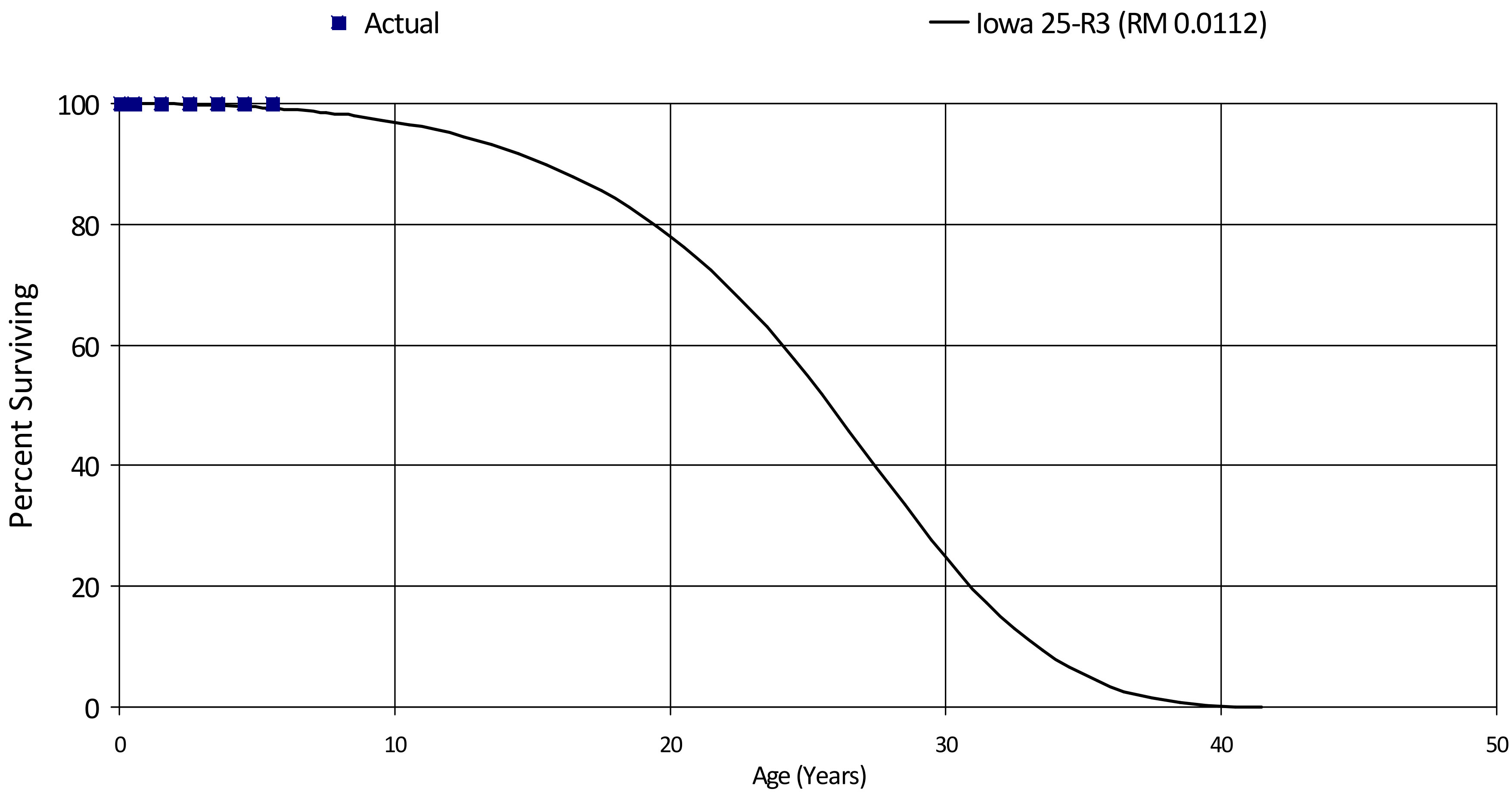
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	20,848,219	0	0.00000	1.00000	100.00
0.5	20,848,219	0	0.00000	1.00000	100.00
1.5	20,570,457	0	0.00000	1.00000	100.00
2.5	17,249,659	0	0.00000	1.00000	100.00
3.5	16,011,941	0	0.00000	1.00000	100.00
4.5	14,423,196	0	0.00000	1.00000	100.00
5.5	12,080,664	0	0.00000	1.00000	100.00
6.5	10,438,080	0	0.00000	1.00000	100.00
7.5	10,408,656	0	0.00000	1.00000	100.00
8.5	9,247,633	0	0.00000	1.00000	100.00
9.5	4,723,137	0	0.00000	1.00000	100.00
10.5	3,608,690	0	0.00000	1.00000	100.00
11.5	3,109,559	0	0.00000	1.00000	100.00
12.5	2,017,289	0	0.00000	1.00000	100.00
13.5	1,153,269	0	0.00000	1.00000	100.00
14.5	942,407	0	0.00000	1.00000	100.00
15.5	700,187	0	0.00000	1.00000	100.00
16.5	653,101	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 55104 - Overhead Collision Avoidance System

Placement Band - 2014 - 2016   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 55104 - Overhead Collision Avoidance System

Placement Band - 2014 - 2016   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

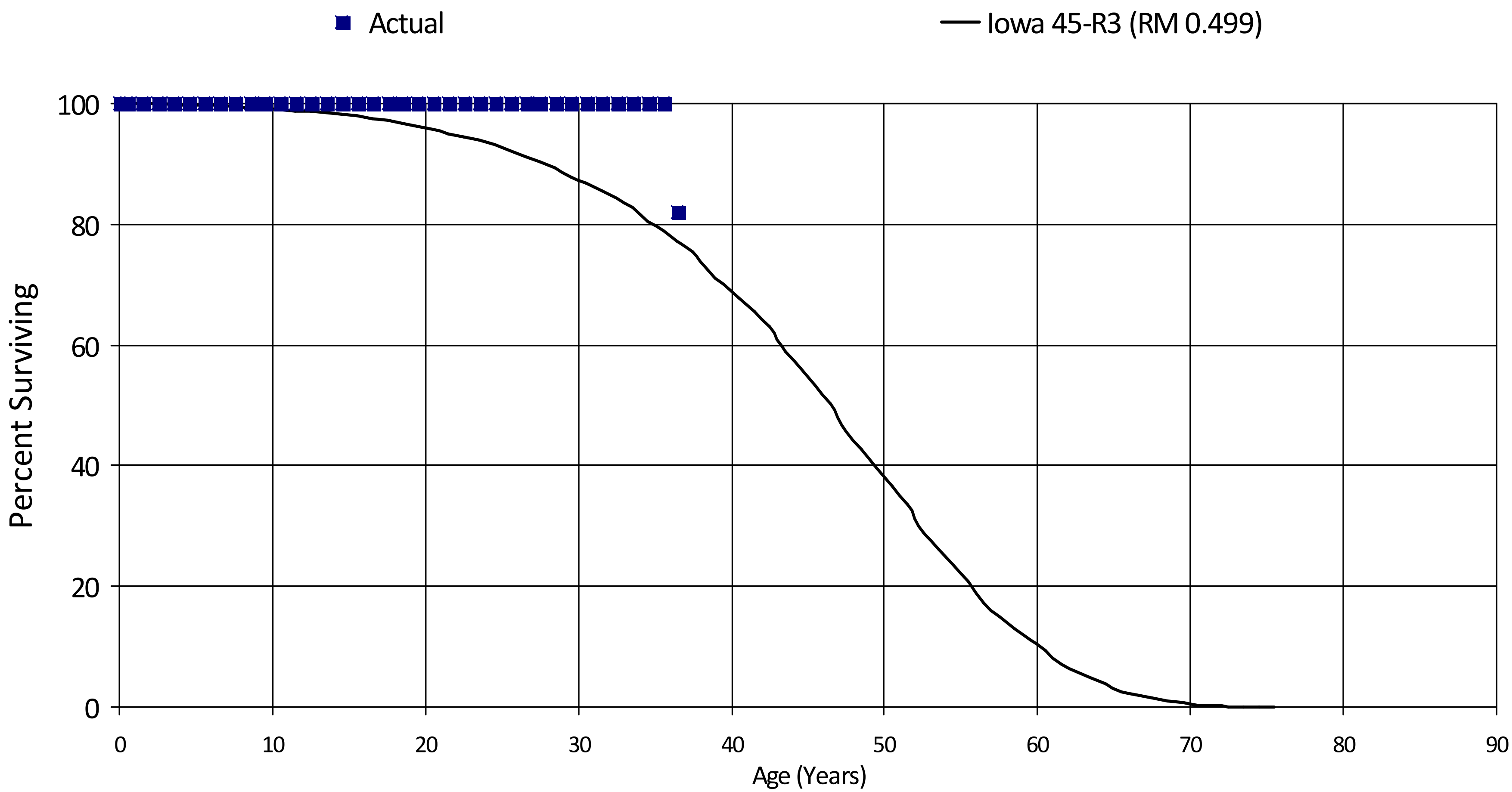
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,037,217	0	0.00000	1.00000	100.00
0.5	2,037,217	0	0.00000	1.00000	100.00
1.5	2,037,217	0	0.00000	1.00000	100.00
2.5	2,037,217	0	0.00000	1.00000	100.00
3.5	2,037,217	0	0.00000	1.00000	100.00
4.5	295,156	0	0.00000	1.00000	100.00
5.5	295,156	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 55201 - Overhead Conductor Services < 60 Kv

Placement Band - 1966 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 55201 - Overhead Conductor Services < 60 Kv

Placement Band - 1966 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	312,606,916	0	0.00000	1.00000	100.00
0.5	312,390,959	0	0.00000	1.00000	100.00
1.5	295,310,417	0	0.00000	1.00000	100.00
2.5	271,896,087	0	0.00000	1.00000	100.00
3.5	253,753,649	0	0.00000	1.00000	100.00
4.5	226,358,536	0	0.00000	1.00000	100.00
5.5	211,244,625	0	0.00000	1.00000	100.00
6.5	206,520,347	0	0.00000	1.00000	100.00
7.5	196,761,802	0	0.00000	1.00000	100.00
8.5	168,139,294	0	0.00000	1.00000	100.00
9.5	165,821,265	0	0.00000	1.00000	100.00
10.5	165,138,019	0	0.00000	1.00000	100.00
11.5	154,463,679	0	0.00000	1.00000	100.00
12.5	142,965,312	0	0.00000	1.00000	100.00
13.5	131,908,117	0	0.00000	1.00000	100.00
14.5	111,999,870	0	0.00000	1.00000	100.00
15.5	102,441,291	0	0.00000	1.00000	100.00
16.5	101,359,560	0	0.00000	1.00000	100.00
17.5	86,123,213	0	0.00000	1.00000	100.00
18.5	81,688,730	0	0.00000	1.00000	100.00
19.5	76,432,686	0	0.00000	1.00000	100.00
20.5	71,154,528	0	0.00000	1.00000	100.00
21.5	58,299,942	0	0.00000	1.00000	100.00
22.5	54,546,450	0	0.00000	1.00000	100.00
23.5	51,053,449	0	0.00000	1.00000	100.00
24.5	47,751,320	0	0.00000	1.00000	100.00
25.5	44,569,001	0	0.00000	1.00000	100.00
26.5	41,081,585	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 55201 - Overhead Conductor Services < 60 Kv

Placement Band - 1966 - 2020   Experience Band - 2013 - 2020

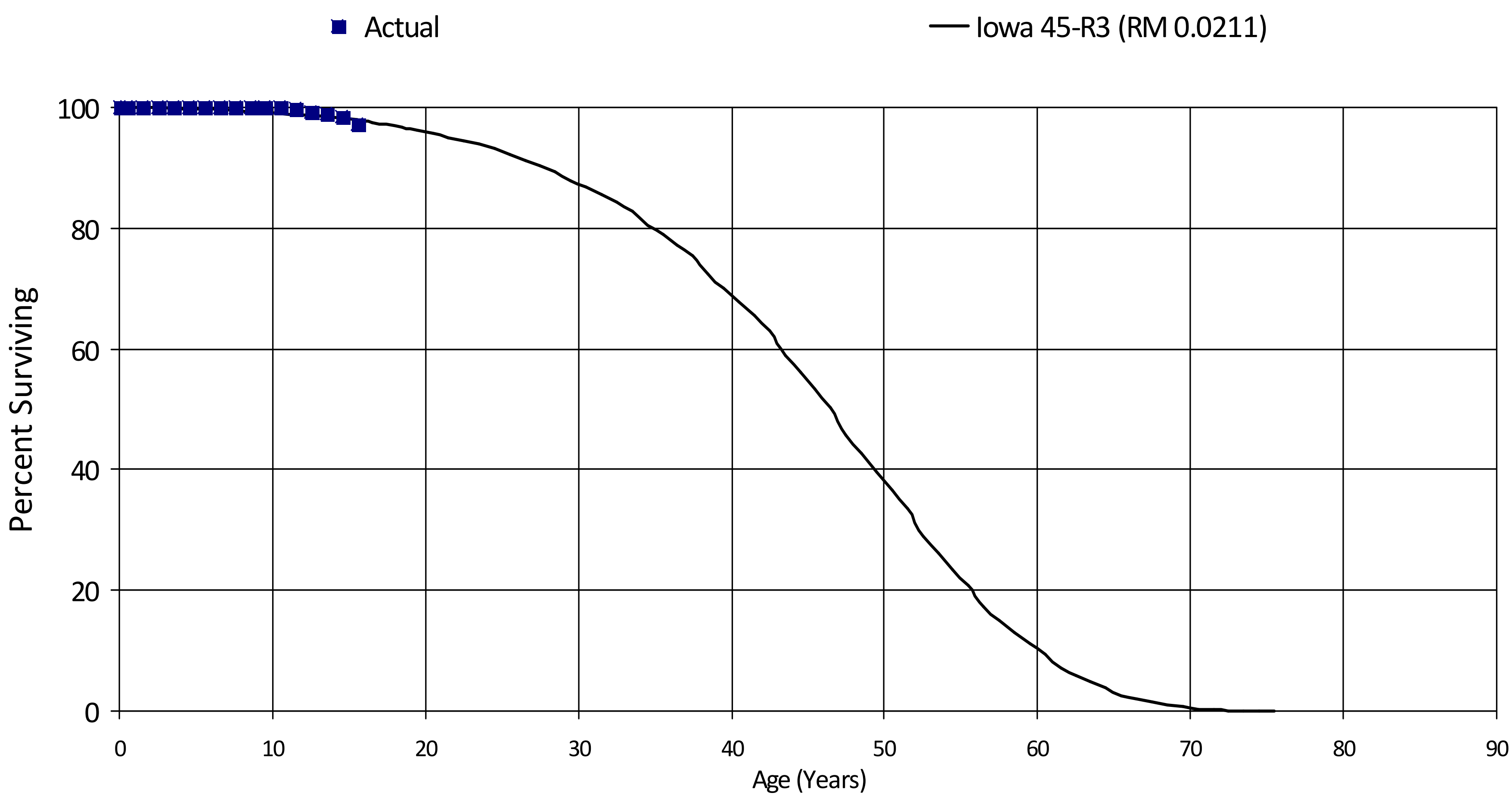
27.5	38,203,001	0	0.00000	1.00000	100.00
28.5	33,663,834	0	0.00000	1.00000	100.00
29.5	28,921,946	0	0.00000	1.00000	100.00
30.5	25,563,787	0	0.00000	1.00000	100.00
31.5	24,043,970	0	0.00000	1.00000	100.00
32.5	19,913,811	0	0.00000	1.00000	100.00
33.5	18,605,395	0	0.00000	1.00000	100.00
34.5	16,316,955	0	0.00000	1.00000	100.00
35.5	14,695,313	2,638,688	0.17956	0.82044	100.00
36.5	10,040,354	9,185,958	0.91490	0.08510	82.04
	Totals:	11,824,646			

BC Hydro Power Authority

Account 55202 - Underground Conductor Services < 60 Kv

Placement Band - 2003 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 55202 - Underground Conductor Services < 60 Kv

Placement Band - 2003 - 2020 Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

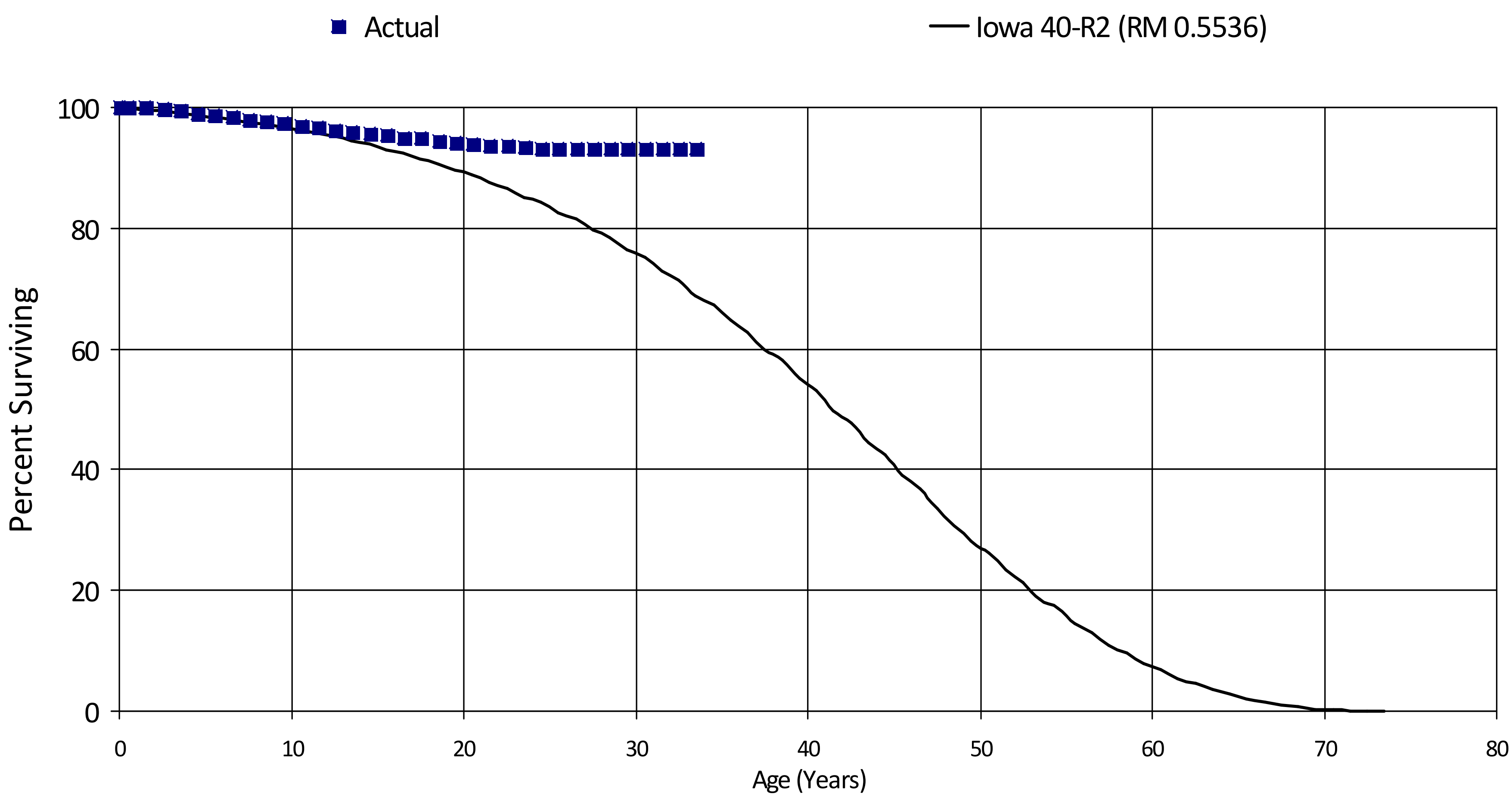
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	114,029,608	0	0.00000	1.00000	100.00
0.5	113,862,334	0	0.00000	1.00000	100.00
1.5	108,506,133	0	0.00000	1.00000	100.00
2.5	99,817,816	0	0.00000	1.00000	100.00
3.5	91,455,441	0	0.00000	1.00000	100.00
4.5	75,101,760	0	0.00000	1.00000	100.00
5.5	69,041,659	0	0.00000	1.00000	100.00
6.5	65,697,583	0	0.00000	1.00000	100.00
7.5	59,200,302	0	0.00000	1.00000	100.00
8.5	50,936,865	0	0.00000	1.00000	100.00
9.5	44,976,444	46,904	0.00104	0.99896	100.00
10.5	41,122,932	77,515	0.00188	0.99812	99.90
11.5	35,114,491	123,927	0.00353	0.99647	99.71
12.5	31,437,323	93,818	0.00298	0.99702	99.36
13.5	22,682,670	112,304	0.00495	0.99505	99.06
14.5	10,422,567	131,216	0.01259	0.98741	98.57
15.5	4,649,270	129,279	0.02781	0.97219	97.33
	Totals:	714,963			

BC Hydro Power Authority

Account 55301 - Cable, Underground < 60 Kv

Placement Band - 1972 - 2020 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 55301 - Cable, Underground < 60 Kv

Placement Band - 1972 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,009,610,034	0	0.00000	1.00000	100.00
0.5	991,434,803	0	0.00000	1.00000	100.00
1.5	928,021,571	1,537,543	0.00166	0.99834	100.00
2.5	862,468,179	3,518,362	0.00408	0.99592	99.83
3.5	791,429,518	2,716,002	0.00343	0.99657	99.42
4.5	736,910,388	2,563,182	0.00348	0.99652	99.08
5.5	689,833,950	2,637,982	0.00382	0.99618	98.74
6.5	646,321,545	2,162,319	0.00335	0.99665	98.36
7.5	608,063,893	1,750,420	0.00288	0.99712	98.03
8.5	565,690,893	1,586,387	0.00280	0.99720	97.75
9.5	525,294,238	2,496,307	0.00475	0.99525	97.48
10.5	471,696,168	1,600,741	0.00339	0.99661	97.02
11.5	410,238,092	1,683,208	0.00410	0.99590	96.69
12.5	335,020,578	1,007,343	0.00301	0.99699	96.29
13.5	290,489,568	1,013,265	0.00349	0.99651	96.00
14.5	253,478,536	807,431	0.00319	0.99681	95.66
15.5	230,232,092	913,161	0.00397	0.99603	95.35
16.5	208,791,393	334,633	0.00160	0.99840	94.97
17.5	178,398,527	604,609	0.00339	0.99661	94.82
18.5	163,827,549	562,292	0.00343	0.99657	94.50
19.5	149,798,630	407,535	0.00272	0.99728	94.18
20.5	139,097,038	261,727	0.00188	0.99812	93.92
21.5	126,076,194	270,722	0.00215	0.99785	93.74
22.5	112,523,813	287,975	0.00256	0.99744	93.54
23.5	98,117,999	200,383	0.00204	0.99796	93.30
24.5	80,314,983	0	0.00000	1.00000	93.11
25.5	65,311,864	0	0.00000	1.00000	93.11
26.5	50,892,644	0	0.00000	1.00000	93.11

BC Hydro Power Authority

Account 55301 - Cable, Underground < 60 Kv

Placement Band - 1972 - 2020   Experience Band - 2013 - 2020

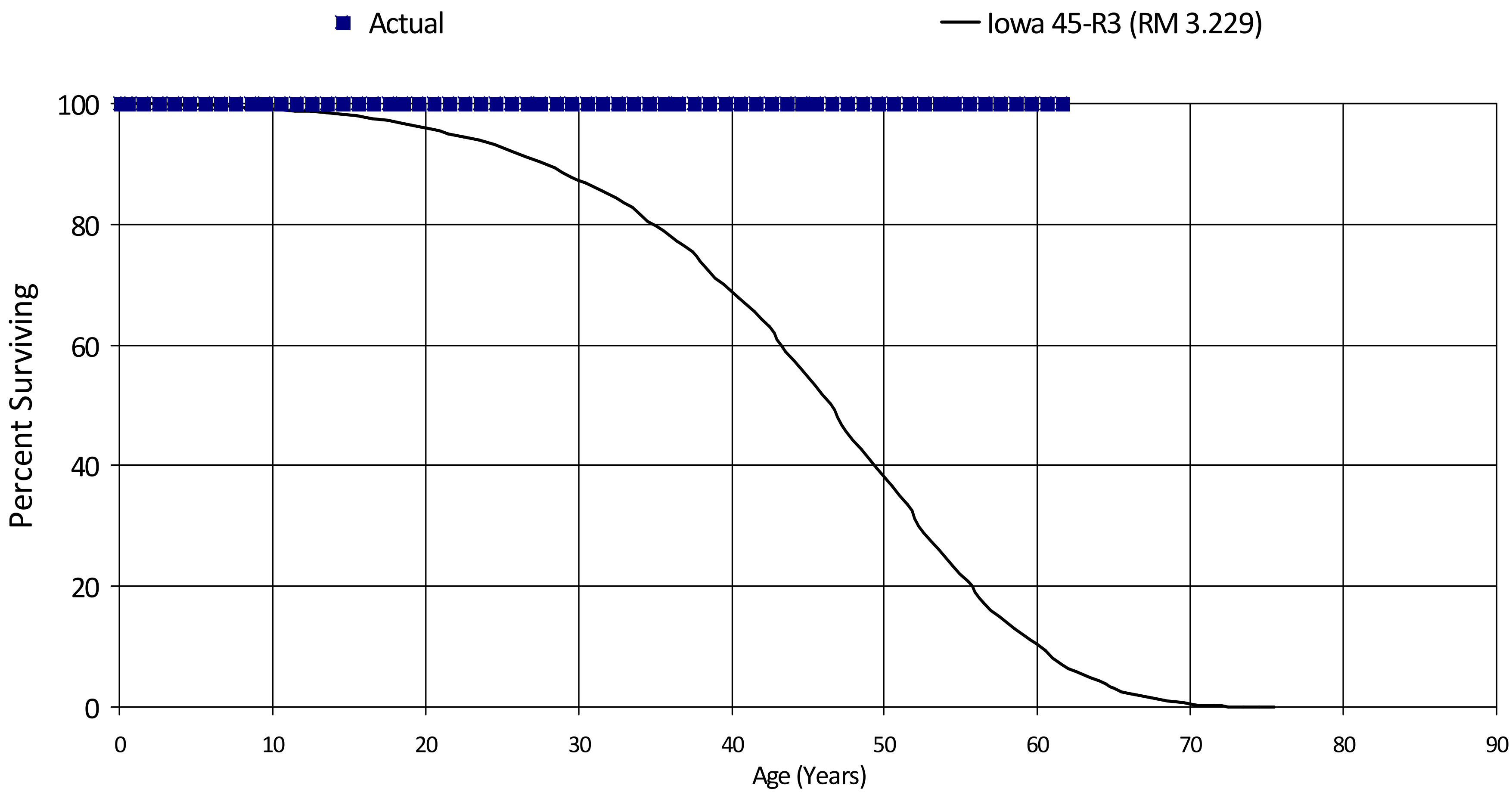
27.5	38,684,127	0	0.00000	1.00000	93.11
28.5	29,174,439	0	0.00000	1.00000	93.11
29.5	23,326,372	0	0.00000	1.00000	93.11
30.5	19,001,613	0	0.00000	1.00000	93.11
31.5	17,528,417	0	0.00000	1.00000	93.11
32.5	14,110,167	0	0.00000	1.00000	93.11
33.5	11,459,936	0	0.00000	1.00000	93.11
	Totals:	30,923,529			

BC Hydro Power Authority

Account 55302 - Cable, Underground > or = 60Kv

Placement Band - 1957 - 2018   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 55302 - Cable, Underground > or = 60Kv

Placement Band - 1957 - 2018   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	108,045,627	0	0.00000	1.00000	100.00
0.5	108,045,627	69,872	0.00065	0.99935	100.00
1.5	107,975,754	0	0.00000	1.00000	99.94
2.5	107,015,969	0	0.00000	1.00000	99.94
3.5	99,484,527	0	0.00000	1.00000	99.94
4.5	87,844,807	0	0.00000	1.00000	99.94
5.5	87,844,807	0	0.00000	1.00000	99.94
6.5	57,576,618	0	0.00000	1.00000	99.94
7.5	56,350,333	0	0.00000	1.00000	99.94
8.5	54,160,156	0	0.00000	1.00000	99.94
9.5	51,440,674	0	0.00000	1.00000	99.94
10.5	46,380,812	0	0.00000	1.00000	99.94
11.5	45,740,081	0	0.00000	1.00000	99.94
12.5	42,828,069	0	0.00000	1.00000	99.94
13.5	40,579,165	0	0.00000	1.00000	99.94
14.5	35,202,515	0	0.00000	1.00000	99.94
15.5	22,575,686	0	0.00000	1.00000	99.94
16.5	22,295,595	0	0.00000	1.00000	99.94
17.5	12,617,533	0	0.00000	1.00000	99.94
18.5	12,431,978	0	0.00000	1.00000	99.94
19.5	12,389,917	0	0.00000	1.00000	99.94
20.5	12,153,306	0	0.00000	1.00000	99.94
21.5	12,140,523	0	0.00000	1.00000	99.94
22.5	11,856,991	0	0.00000	1.00000	99.94
23.5	11,400,562	0	0.00000	1.00000	99.94
24.5	11,399,707	0	0.00000	1.00000	99.94
25.5	11,295,193	0	0.00000	1.00000	99.94
26.5	11,295,193	0	0.00000	1.00000	99.94

BC Hydro Power Authority

Account 55302 - Cable, Underground > or = 60Kv

Placement Band - 1957 - 2018   Experience Band - 2013 - 2020

27.5	11,275,471	0	0.00000	1.00000	99.94
28.5	11,275,471	0	0.00000	1.00000	99.94
29.5	11,275,471	0	0.00000	1.00000	99.94
30.5	11,275,471	0	0.00000	1.00000	99.94
31.5	11,272,775	0	0.00000	1.00000	99.94
32.5	11,213,665	0	0.00000	1.00000	99.94
33.5	11,213,665	0	0.00000	1.00000	99.94
34.5	11,213,665	0	0.00000	1.00000	99.94
35.5	11,178,165	0	0.00000	1.00000	99.94
36.5	11,178,165	0	0.00000	1.00000	99.94
37.5	8,663,688	0	0.00000	1.00000	99.94
38.5	8,610,061	0	0.00000	1.00000	99.94
39.5	8,211,428	0	0.00000	1.00000	99.94
40.5	8,211,428	0	0.00000	1.00000	99.94
41.5	8,023,521	0	0.00000	1.00000	99.94
42.5	7,415,974	0	0.00000	1.00000	99.94
43.5	7,415,974	0	0.00000	1.00000	99.94
44.5	7,415,974	0	0.00000	1.00000	99.94
45.5	6,200,126	0	0.00000	1.00000	99.94
46.5	6,200,126	0	0.00000	1.00000	99.94
47.5	6,200,126	0	0.00000	1.00000	99.94
48.5	6,200,126	0	0.00000	1.00000	99.94
49.5	6,200,126	0	0.00000	1.00000	99.94
50.5	6,200,126	0	0.00000	1.00000	99.94
51.5	6,200,126	0	0.00000	1.00000	99.94
52.5	6,200,126	0	0.00000	1.00000	99.94
53.5	6,200,126	0	0.00000	1.00000	99.94
54.5	6,200,126	0	0.00000	1.00000	99.94
55.5	6,200,126	0	0.00000	1.00000	99.94
56.5	5,871,801	0	0.00000	1.00000	99.94
57.5	5,871,801	0	0.00000	1.00000	99.94

BC Hydro Power Authority

Account 55302 - Cable, Underground > or = 60Kv

Placement Band - 1957 - 2018   Experience Band - 2013 - 2020

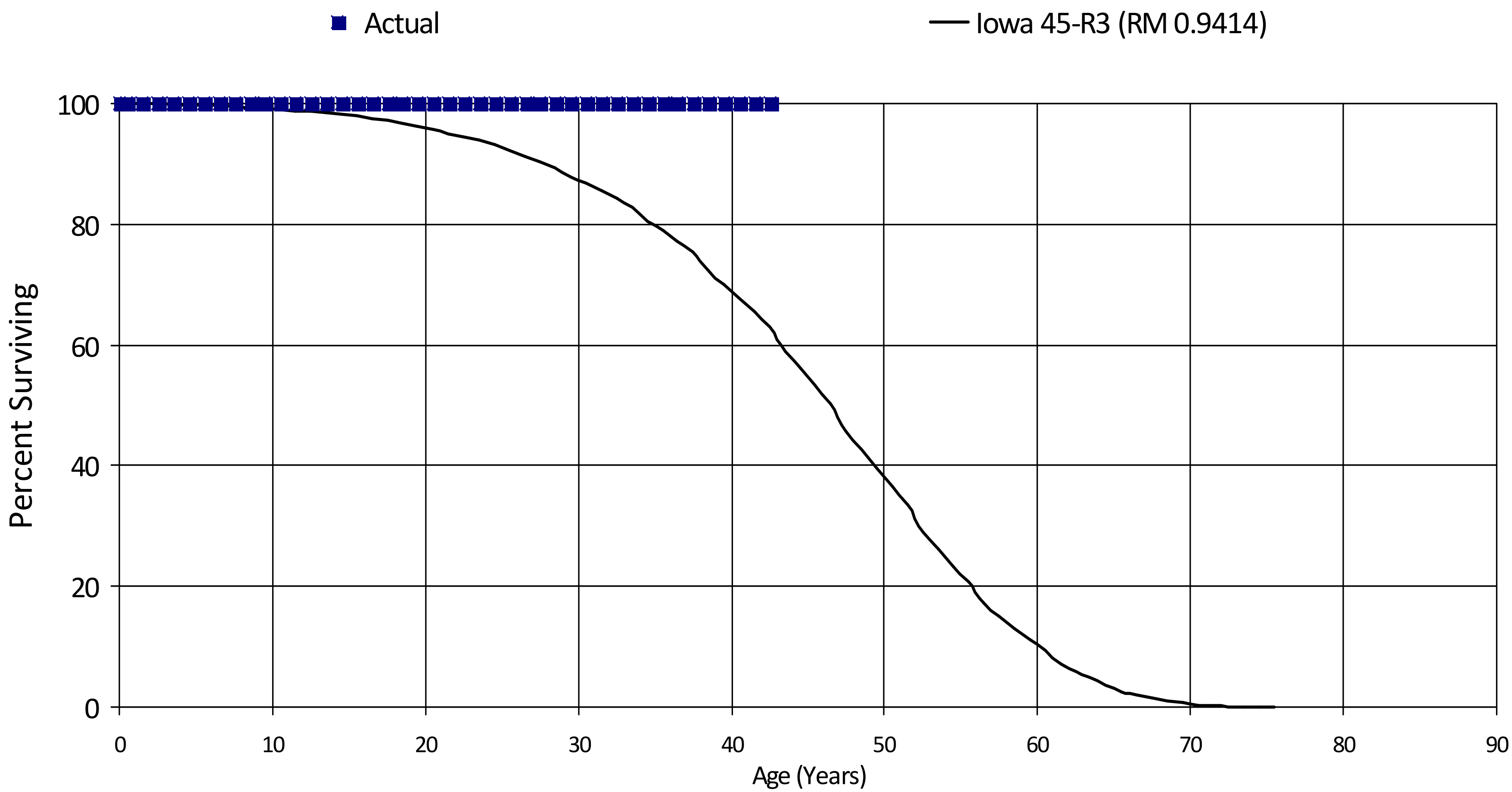
58.5	5,871,801	0	0.00000	1.00000	99.94
59.5	5,871,801	0	0.00000	1.00000	99.94
60.5	5,862,909	0	0.00000	1.00000	99.94
61.5	5,386,824	0	0.00000	1.00000	99.94
	Totals:	69,872			

BC Hydro Power Authority

Account 55303 - Cable, Submarine > or = 60 Kv

Placement Band - 1956 - 2012   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 55303 - Cable, Submarine > or = 60 Kv

Placement Band - 1956 - 2012   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	270,715,556	0	0.00000	1.00000	100.00
0.5	270,715,556	0	0.00000	1.00000	100.00
1.5	270,715,556	0	0.00000	1.00000	100.00
2.5	270,715,556	0	0.00000	1.00000	100.00
3.5	270,715,556	0	0.00000	1.00000	100.00
4.5	270,715,556	0	0.00000	1.00000	100.00
5.5	270,715,556	0	0.00000	1.00000	100.00
6.5	270,715,556	0	0.00000	1.00000	100.00
7.5	270,715,556	0	0.00000	1.00000	100.00
8.5	249,566,056	0	0.00000	1.00000	100.00
9.5	249,566,056	0	0.00000	1.00000	100.00
10.5	248,775,293	0	0.00000	1.00000	100.00
11.5	247,939,929	0	0.00000	1.00000	100.00
12.5	122,879,165	0	0.00000	1.00000	100.00
13.5	122,315,694	0	0.00000	1.00000	100.00
14.5	122,179,433	0	0.00000	1.00000	100.00
15.5	122,179,433	0	0.00000	1.00000	100.00
16.5	122,179,433	0	0.00000	1.00000	100.00
17.5	120,494,905	0	0.00000	1.00000	100.00
18.5	120,494,905	0	0.00000	1.00000	100.00
19.5	120,494,905	0	0.00000	1.00000	100.00
20.5	120,494,905	0	0.00000	1.00000	100.00
21.5	120,494,905	0	0.00000	1.00000	100.00
22.5	120,494,905	0	0.00000	1.00000	100.00
23.5	120,494,905	0	0.00000	1.00000	100.00
24.5	120,494,905	0	0.00000	1.00000	100.00
25.5	115,760,255	0	0.00000	1.00000	100.00
26.5	115,760,255	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 55303 - Cable, Submarine > or = 60 Kv

Placement Band - 1956 - 2012 Experience Band - 2020 - 2020

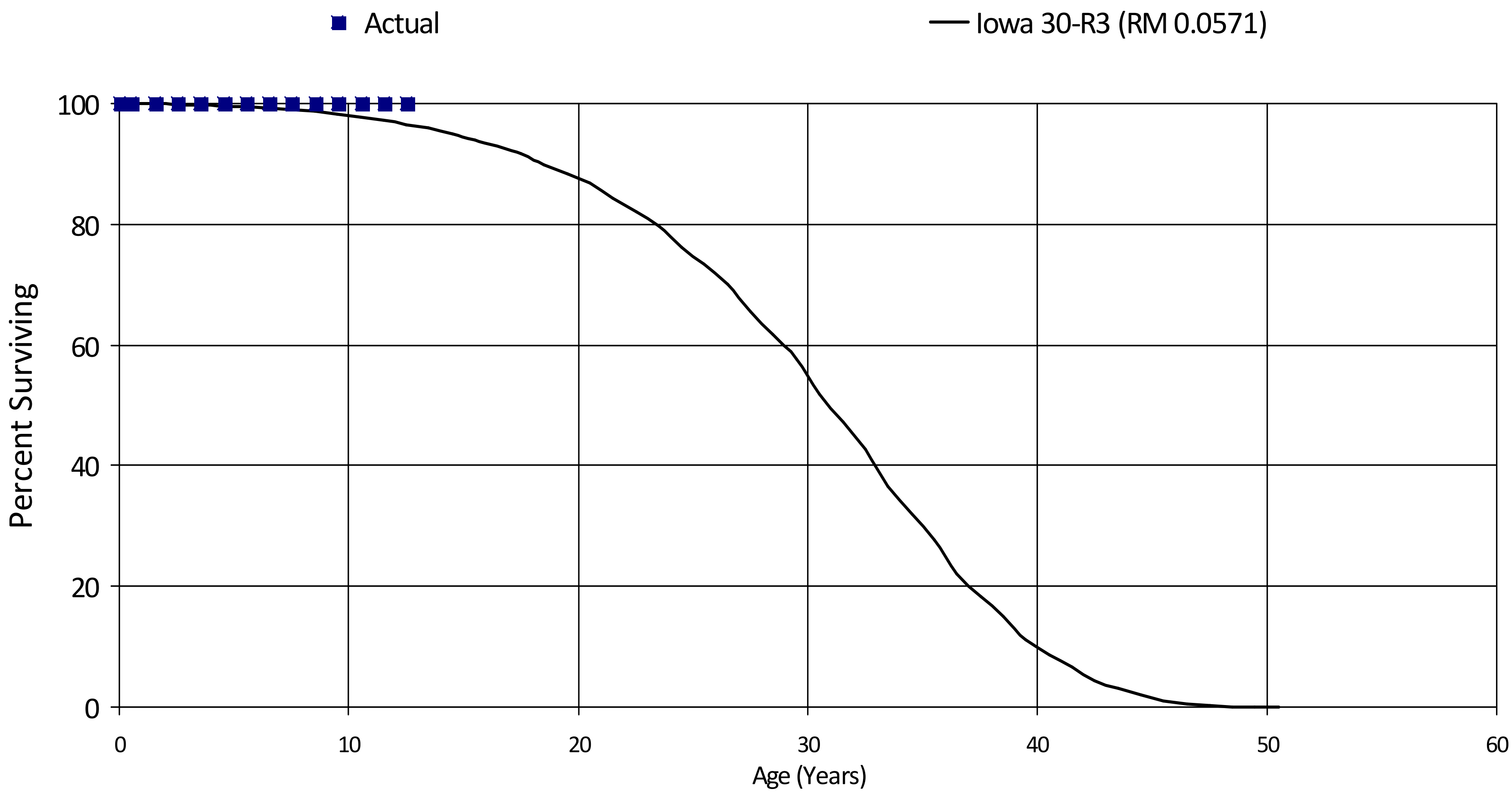
27.5	115,760,255	0	0.00000	1.00000	100.00
28.5	115,760,255	0	0.00000	1.00000	100.00
29.5	115,760,255	0	0.00000	1.00000	100.00
30.5	115,760,255	0	0.00000	1.00000	100.00
31.5	115,760,255	0	0.00000	1.00000	100.00
32.5	115,760,255	0	0.00000	1.00000	100.00
33.5	115,760,255	0	0.00000	1.00000	100.00
34.5	115,760,255	0	0.00000	1.00000	100.00
35.5	56,752,950	0	0.00000	1.00000	100.00
36.5	3,467,135	0	0.00000	1.00000	100.00
37.5	3,467,135	0	0.00000	1.00000	100.00
38.5	3,467,135	0	0.00000	1.00000	100.00
39.5	3,168,559	0	0.00000	1.00000	100.00
40.5	3,168,559	0	0.00000	1.00000	100.00
41.5	3,168,559	0	0.00000	1.00000	100.00
42.5	3,168,559	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 55304 - Cable, Submarine < 60 Kv

Placement Band - 2004 - 2020   Experience Band - 2018 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 55304 - Cable, Submarine < 60 Kv

Placement Band - 2004 - 2020 Experience Band - 2018 - 2020

RETIREMENT RATE ANALYSIS

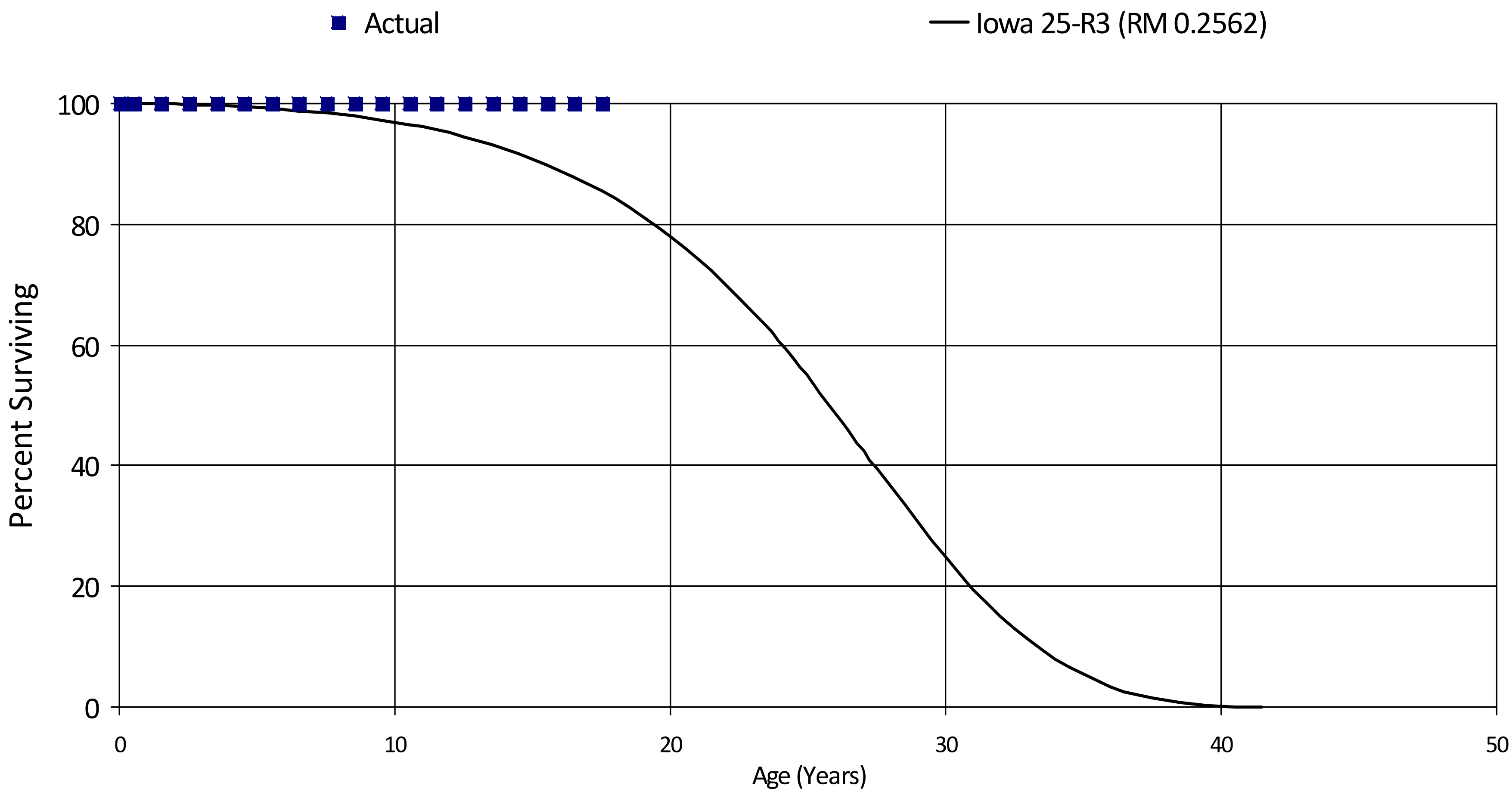
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	63,797,060	0	0.00000	1.00000	100.00
0.5	63,327,152	0	0.00000	1.00000	100.00
1.5	62,146,934	0	0.00000	1.00000	100.00
2.5	50,721,866	0	0.00000	1.00000	100.00
3.5	45,237,130	0	0.00000	1.00000	100.00
4.5	35,191,265	0	0.00000	1.00000	100.00
5.5	33,208,438	0	0.00000	1.00000	100.00
6.5	24,044,384	0	0.00000	1.00000	100.00
7.5	16,864,054	0	0.00000	1.00000	100.00
8.5	3,434,882	0	0.00000	1.00000	100.00
9.5	3,411,946	0	0.00000	1.00000	100.00
10.5	3,266,906	0	0.00000	1.00000	100.00
11.5	3,250,473	0	0.00000	1.00000	100.00
12.5	3,235,827	24,648	0.00762	0.99238	100.00
	Totals:	24,648			

BC Hydro Power Authority

Account 55305 - Cable, Submarine , Pumping Plant

Placement Band - 1995 - 2019   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 55305 - Cable, Submarine , Pumping Plant

Placement Band - 1995 - 2019   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

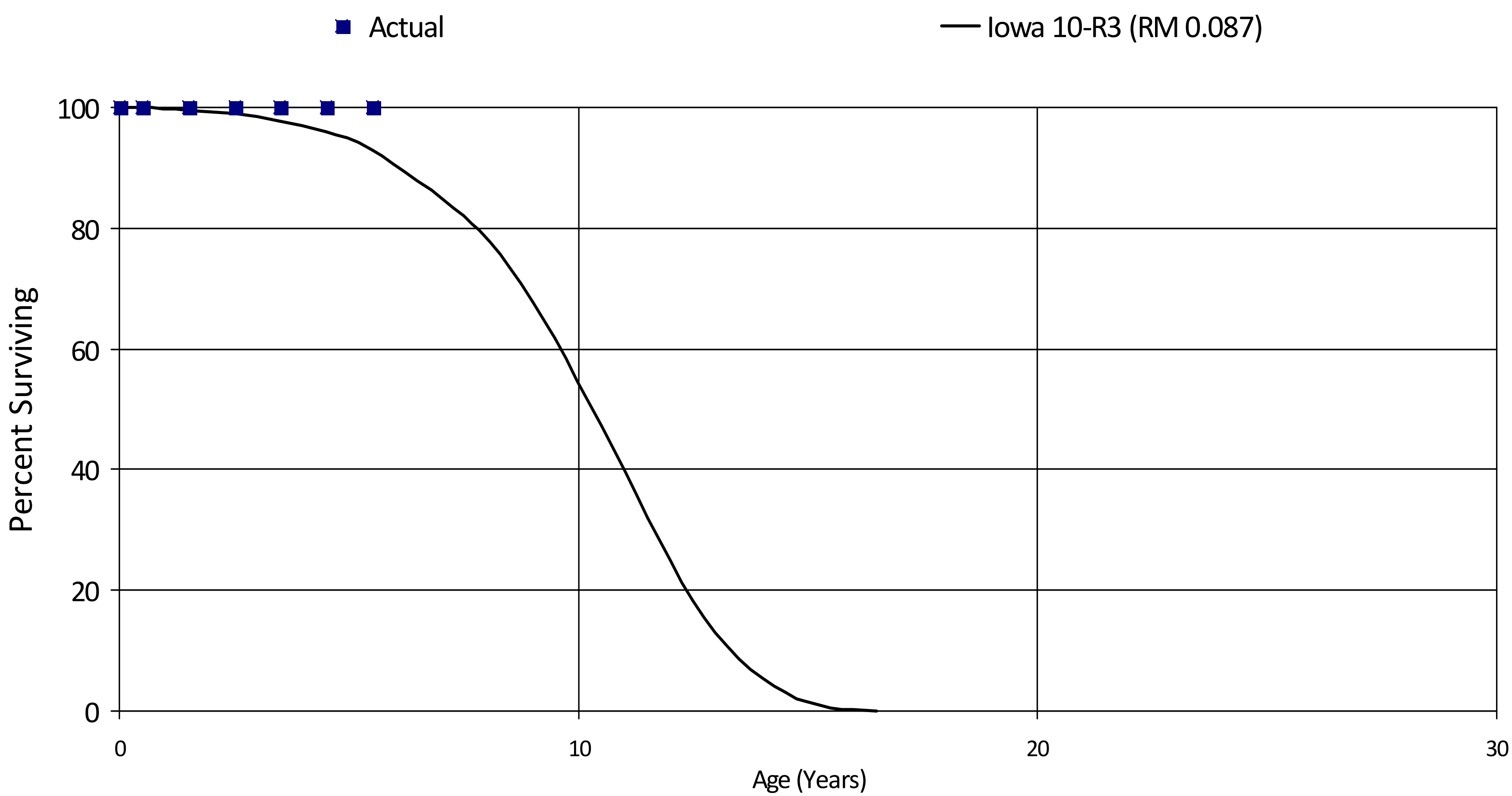
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	24,910,795	0	0.00000	1.00000	100.00
0.5	24,910,795	0	0.00000	1.00000	100.00
1.5	24,851,789	0	0.00000	1.00000	100.00
2.5	24,851,789	0	0.00000	1.00000	100.00
3.5	24,851,789	0	0.00000	1.00000	100.00
4.5	23,959,777	0	0.00000	1.00000	100.00
5.5	23,959,777	0	0.00000	1.00000	100.00
6.5	23,959,777	0	0.00000	1.00000	100.00
7.5	23,959,777	0	0.00000	1.00000	100.00
8.5	23,843,666	0	0.00000	1.00000	100.00
9.5	23,843,666	0	0.00000	1.00000	100.00
10.5	17,419,937	0	0.00000	1.00000	100.00
11.5	11,493,327	0	0.00000	1.00000	100.00
12.5	859,898	0	0.00000	1.00000	100.00
13.5	813,115	0	0.00000	1.00000	100.00
14.5	767,826	0	0.00000	1.00000	100.00
15.5	767,826	0	0.00000	1.00000	100.00
16.5	767,826	0	0.00000	1.00000	100.00
17.5	532,679	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 55308 - Cable Monitor System, Underground > = 60Kv

Placement Band - 2014 - 2015   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 55308 - Cable Monitor System, Underground > = 60Kv

Placement Band - 2014 - 2015   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

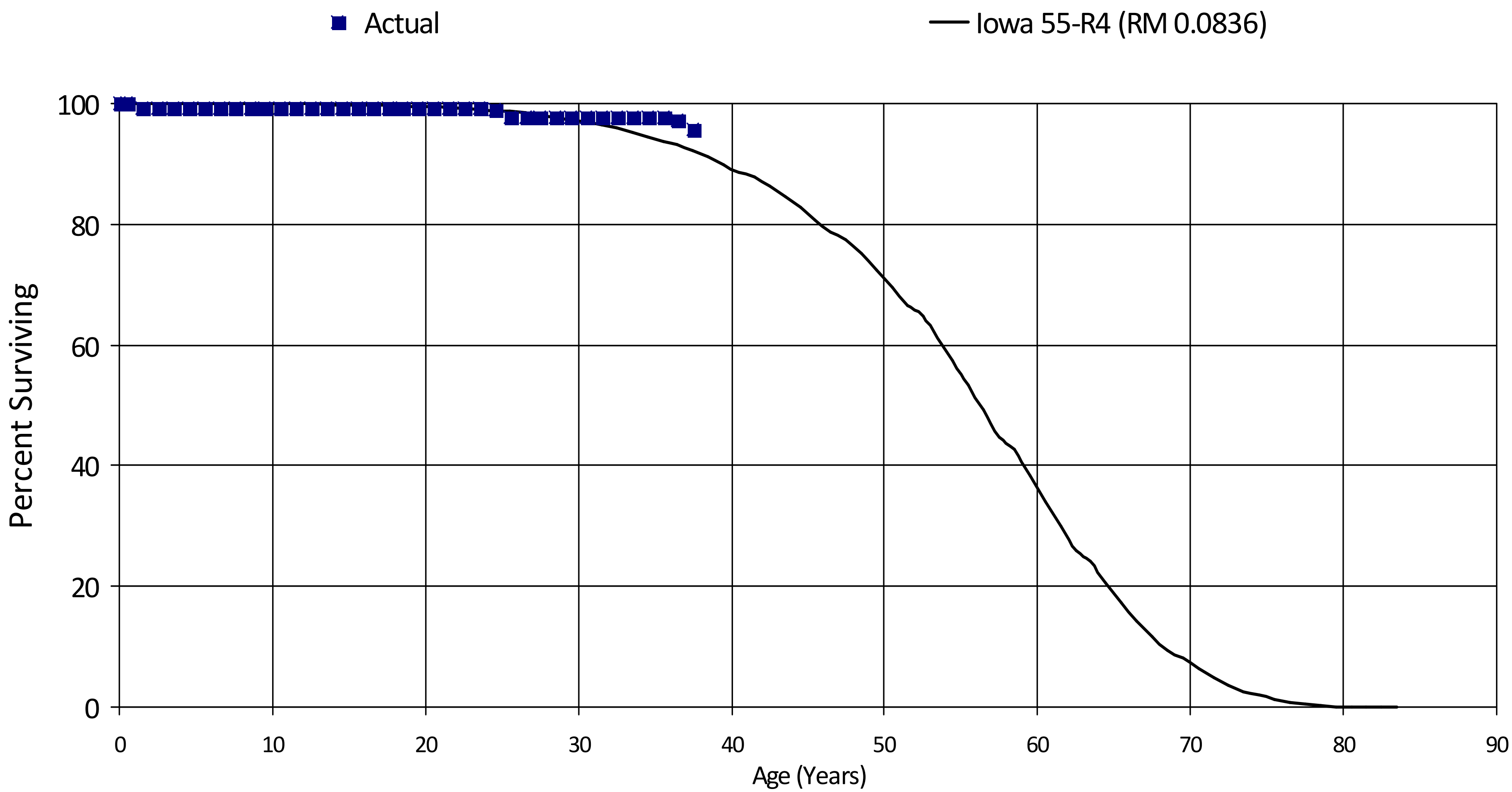
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,185,321	0	0.00000	1.00000	100.00
0.5	2,185,321	0	0.00000	1.00000	100.00
1.5	2,185,321	0	0.00000	1.00000	100.00
2.5	2,185,321	0	0.00000	1.00000	100.00
3.5	2,185,321	0	0.00000	1.00000	100.00
4.5	2,185,321	0	0.00000	1.00000	100.00
5.5	2,140,317	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 55401 - Buswork & Station Conductor

Placement Band - 1967 - 2020 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 55401 - Buswork & Station Conductor

Placement Band - 1967 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	438,262,344	0	0.00000	1.00000	100.00
0.5	436,187,389	2,770,253	0.00635	0.99365	100.00
1.5	405,331,493	0	0.00000	1.00000	99.36
2.5	392,051,910	0	0.00000	1.00000	99.36
3.5	376,243,289	0	0.00000	1.00000	99.36
4.5	343,492,844	0	0.00000	1.00000	99.36
5.5	308,776,070	0	0.00000	1.00000	99.36
6.5	278,873,536	0	0.00000	1.00000	99.36
7.5	255,612,207	0	0.00000	1.00000	99.36
8.5	132,958,321	0	0.00000	1.00000	99.36
9.5	124,631,020	0	0.00000	1.00000	99.36
10.5	101,066,300	115,446	0.00114	0.99886	99.36
11.5	85,652,170	0	0.00000	1.00000	99.25
12.5	76,082,670	0	0.00000	1.00000	99.25
13.5	66,403,752	0	0.00000	1.00000	99.25
14.5	59,671,849	0	0.00000	1.00000	99.25
15.5	54,035,892	0	0.00000	1.00000	99.25
16.5	46,814,536	0	0.00000	1.00000	99.25
17.5	41,214,459	3,580	0.00009	0.99991	99.25
18.5	39,778,203	0	0.00000	1.00000	99.24
19.5	38,239,097	0	0.00000	1.00000	99.24
20.5	36,948,898	0	0.00000	1.00000	99.24
21.5	34,645,015	0	0.00000	1.00000	99.24
22.5	33,082,563	0	0.00000	1.00000	99.24
23.5	32,334,346	74,675	0.00231	0.99769	99.24
24.5	28,292,965	405,769	0.01434	0.98566	99.01
25.5	26,046,152	0	0.00000	1.00000	97.59
26.5	22,636,367	0	0.00000	1.00000	97.59

BC Hydro Power Authority

Account 55401 - Buswork & Station Conductor

Placement Band - 1967 - 2020   Experience Band - 2013 - 2020

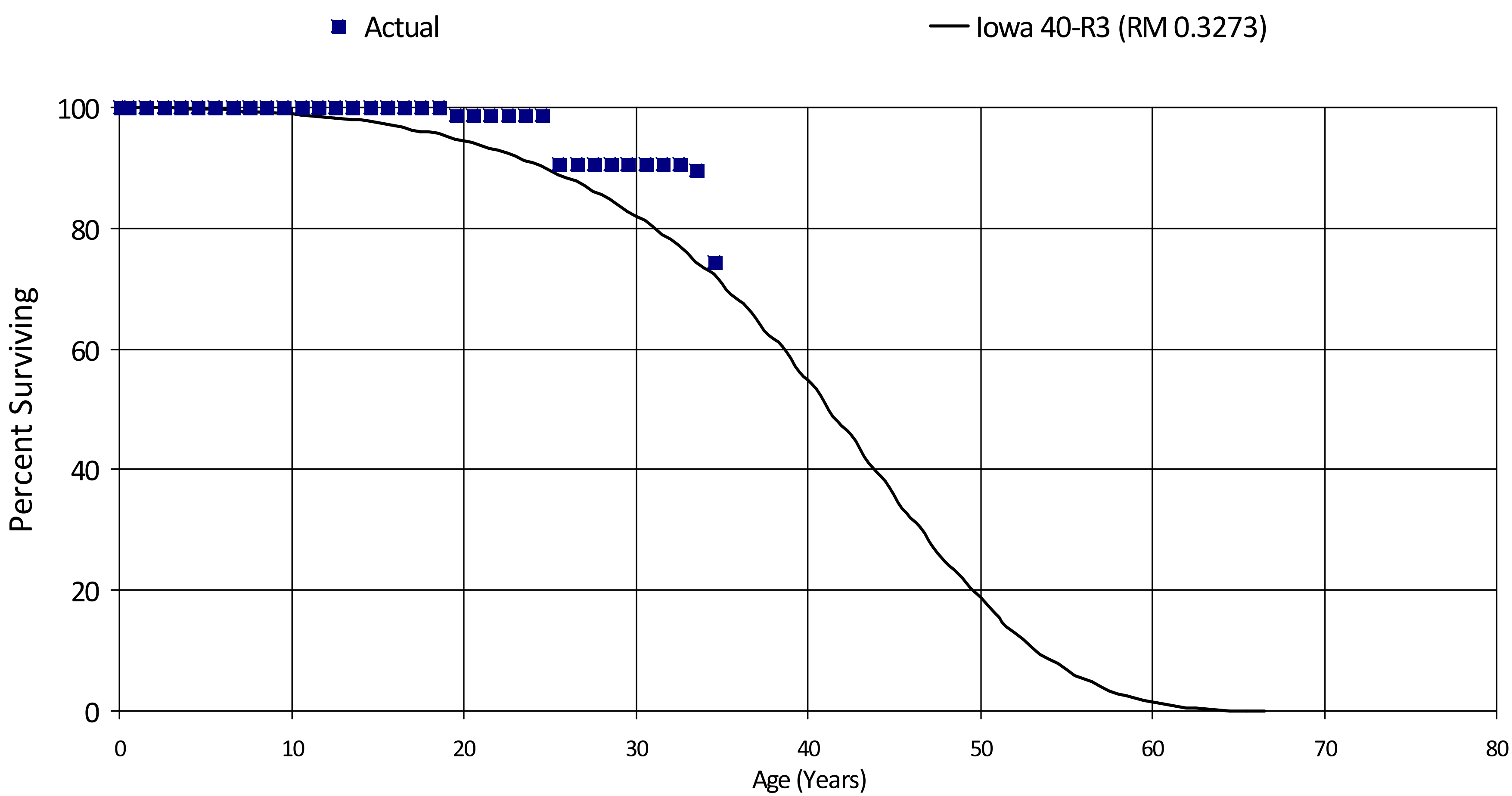
27.5	22,577,743	0	0.00000	1.00000	97.59
28.5	21,410,629	0	0.00000	1.00000	97.59
29.5	19,865,111	0	0.00000	1.00000	97.59
30.5	18,767,128	0	0.00000	1.00000	97.59
31.5	18,524,454	0	0.00000	1.00000	97.59
32.5	18,094,244	0	0.00000	1.00000	97.59
33.5	17,453,389	0	0.00000	1.00000	97.59
34.5	16,878,978	0	0.00000	1.00000	97.59
35.5	12,447,639	62,916	0.00505	0.99495	97.59
36.5	10,084,062	157,954	0.01566	0.98434	97.10
37.5	8,553,946	3,042,041	0.35563	0.64437	95.58
	Totals:	6,632,634			

BC Hydro Power Authority

Account 55501 - Grounding Systems

Placement Band - 1971 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 55501 - Grounding Systems

Placement Band - 1971 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	75,210,550	0	0.00000	1.00000	100.00
0.5	74,370,782	0	0.00000	1.00000	100.00
1.5	72,260,296	0	0.00000	1.00000	100.00
2.5	67,842,542	0	0.00000	1.00000	100.00
3.5	58,630,837	0	0.00000	1.00000	100.00
4.5	46,096,806	0	0.00000	1.00000	100.00
5.5	40,683,122	0	0.00000	1.00000	100.00
6.5	36,973,338	0	0.00000	1.00000	100.00
7.5	32,849,489	0	0.00000	1.00000	100.00
8.5	29,714,423	0	0.00000	1.00000	100.00
9.5	26,421,797	0	0.00000	1.00000	100.00
10.5	23,048,637	0	0.00000	1.00000	100.00
11.5	19,114,762	0	0.00000	1.00000	100.00
12.5	14,353,527	0	0.00000	1.00000	100.00
13.5	8,481,404	0	0.00000	1.00000	100.00
14.5	7,482,123	0	0.00000	1.00000	100.00
15.5	7,275,519	0	0.00000	1.00000	100.00
16.5	6,676,961	0	0.00000	1.00000	100.00
17.5	5,883,175	0	0.00000	1.00000	100.00
18.5	5,680,341	76,895	0.01354	0.98646	100.00
19.5	5,361,706	0	0.00000	1.00000	98.65
20.5	5,142,705	0	0.00000	1.00000	98.65
21.5	4,837,533	0	0.00000	1.00000	98.65
22.5	4,677,526	0	0.00000	1.00000	98.65
23.5	4,411,515	0	0.00000	1.00000	98.65
24.5	4,036,492	328,235	0.08132	0.91868	98.65
25.5	3,520,076	0	0.00000	1.00000	90.63
26.5	3,226,858	0	0.00000	1.00000	90.63

BC Hydro Power Authority

Account 55501 - Grounding Systems

Placement Band - 1971 - 2020 Experience Band - 2013 - 2020

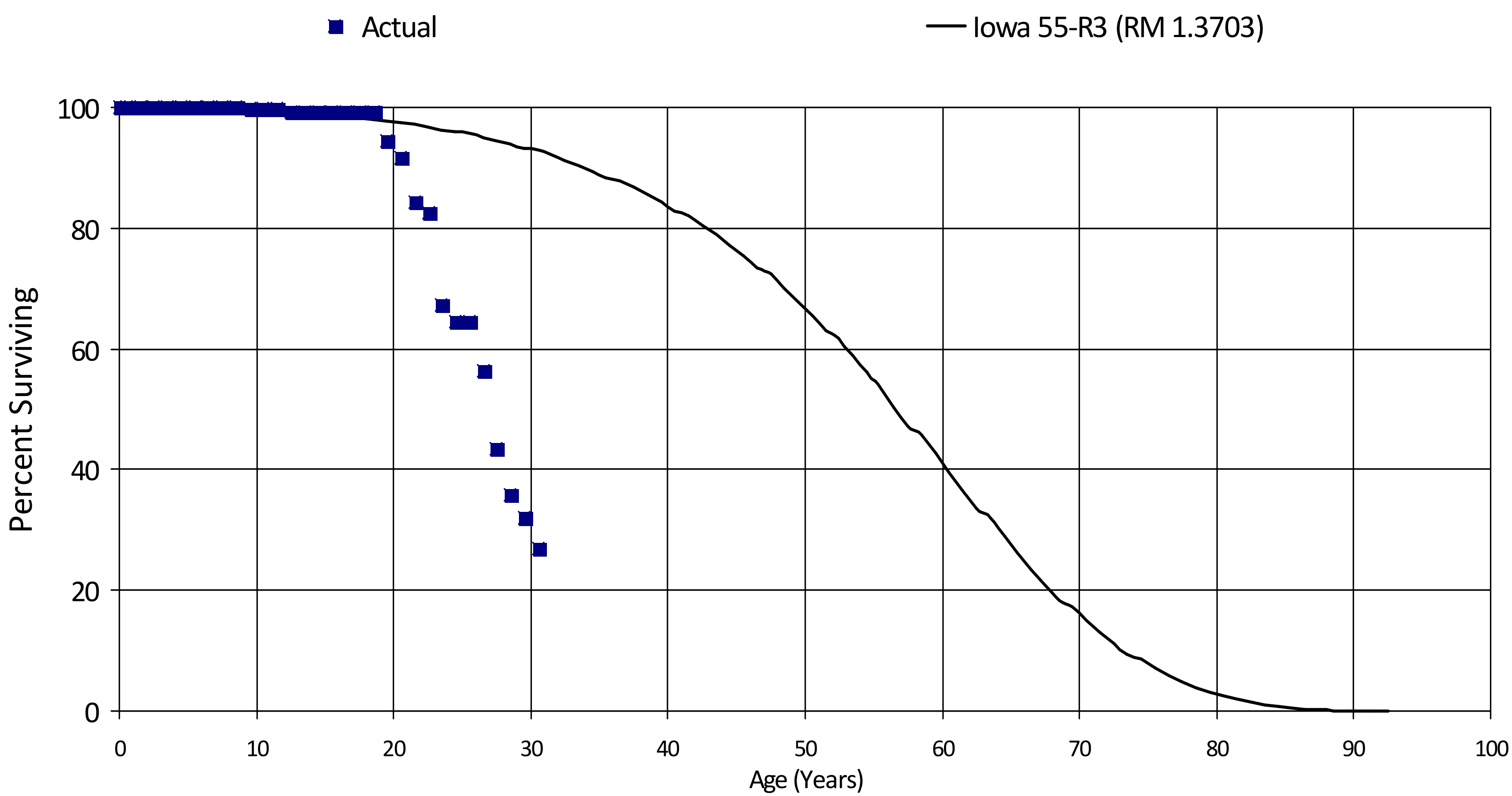
27.5	3,226,331	0	0.00000	1.00000	90.63
28.5	3,191,961	0	0.00000	1.00000	90.63
29.5	3,046,478	0	0.00000	1.00000	90.63
30.5	2,531,166	0	0.00000	1.00000	90.63
31.5	2,380,632	0	0.00000	1.00000	90.63
32.5	2,364,683	27,575	0.01166	0.98834	90.63
33.5	2,282,515	388,353	0.17014	0.82986	89.57
34.5	1,726,830	857,150	0.49637	0.50363	74.33
	Totals:	1,678,208			

BC Hydro Power Authority

Account 56001 - Insulators

Placement Band - 1967 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 56001 - Insulators

Placement Band - 1967 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	109,139,109	0	0.00000	1.00000	100.00
0.5	108,993,707	0	0.00000	1.00000	100.00
1.5	107,796,319	0	0.00000	1.00000	100.00
2.5	106,177,272	0	0.00000	1.00000	100.00
3.5	104,328,124	0	0.00000	1.00000	100.00
4.5	100,335,217	0	0.00000	1.00000	100.00
5.5	91,725,922	0	0.00000	1.00000	100.00
6.5	88,053,974	0	0.00000	1.00000	100.00
7.5	74,110,986	73,151	0.00099	0.99901	100.00
8.5	71,538,211	91,894	0.00128	0.99872	99.90
9.5	67,110,542	0	0.00000	1.00000	99.77
10.5	57,955,708	0	0.00000	1.00000	99.77
11.5	49,190,322	205,454	0.00418	0.99582	99.77
12.5	44,979,389	0	0.00000	1.00000	99.35
13.5	16,106,287	0	0.00000	1.00000	99.35
14.5	11,822,027	0	0.00000	1.00000	99.35
15.5	8,250,127	0	0.00000	1.00000	99.35
16.5	7,777,322	0	0.00000	1.00000	99.35
17.5	6,201,007	7,774	0.00125	0.99875	99.35
18.5	4,102,718	196,141	0.04781	0.95219	99.23
19.5	3,906,577	118,104	0.03023	0.96977	94.49
20.5	3,788,473	307,216	0.08109	0.91891	91.63
21.5	3,481,257	74,085	0.02128	0.97872	84.20
22.5	3,407,172	629,343	0.18471	0.81529	82.41
23.5	2,777,829	110,808	0.03989	0.96011	67.19
24.5	2,667,021	666	0.00025	0.99975	64.51
25.5	2,666,355	332,930	0.12486	0.87514	64.49
26.5	2,333,426	543,583	0.23295	0.76705	56.44

BC Hydro Power Authority

Account 56001 - Insulators

Placement Band - 1967 - 2020 Experience Band - 2013 - 2020

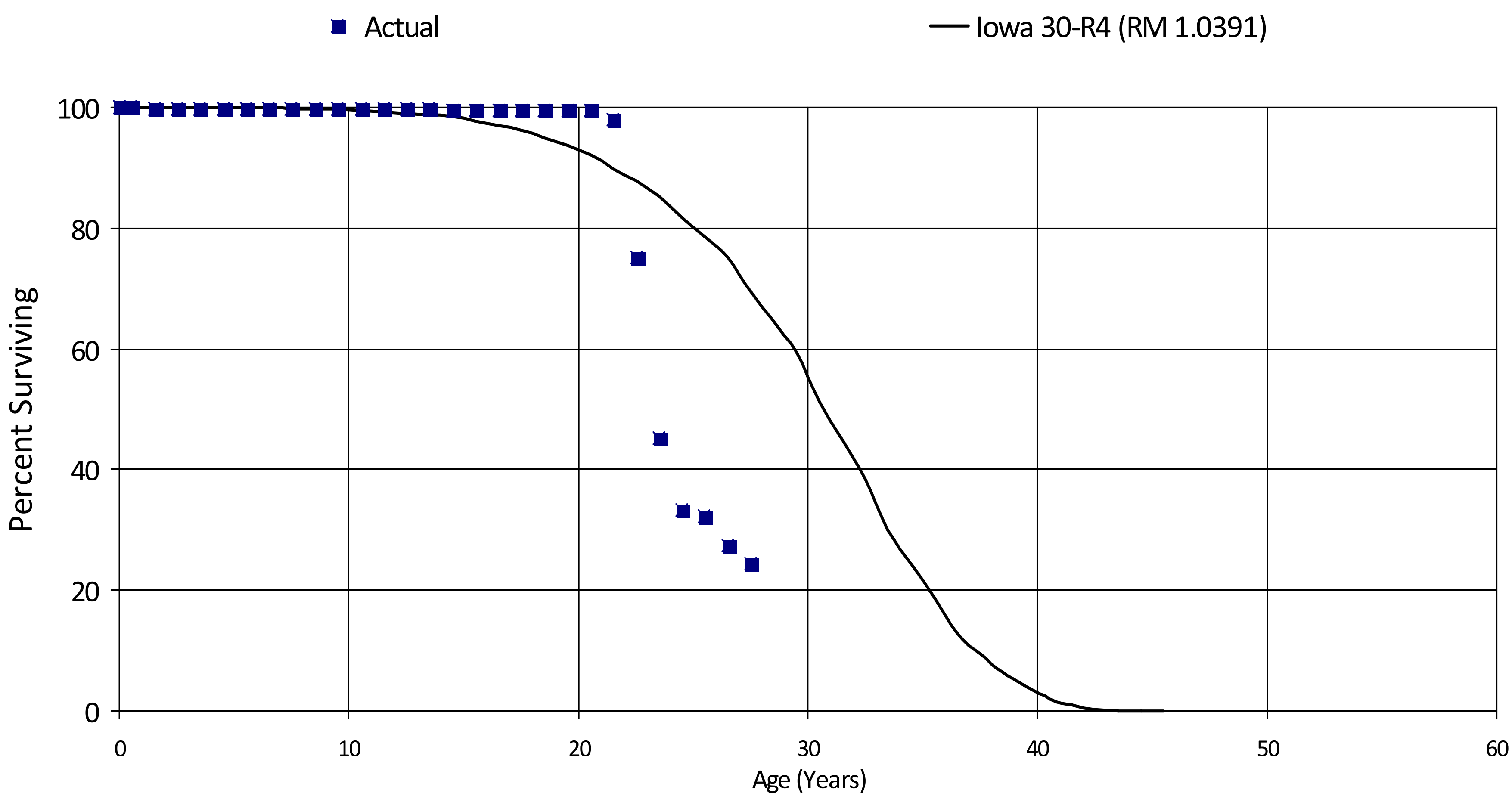
27.5	1,789,843	307,165	0.17162	0.82838	43.29
28.5	1,482,678	160,511	0.10826	0.89174	35.86
29.5	1,322,167	212,142	0.16045	0.83955	31.98
30.5	1,110,024	709,923	0.63956	0.36044	26.85
	Totals:	4,080,890			

BC Hydro Power Authority

Account 57001 - Arrestor, Surge

Placement Band - 1981 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 57001 - Arrestor, Surge

Placement Band - 1981 - 2020 Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	54,505,150	0	0.00000	1.00000	100.00
0.5	54,161,638	86,841	0.00160	0.99840	100.00
1.5	51,417,561	0	0.00000	1.00000	99.84
2.5	49,653,085	0	0.00000	1.00000	99.84
3.5	46,499,288	0	0.00000	1.00000	99.84
4.5	42,546,641	0	0.00000	1.00000	99.84
5.5	36,662,978	0	0.00000	1.00000	99.84
6.5	30,131,275	0	0.00000	1.00000	99.84
7.5	28,139,846	16,955	0.00060	0.99940	99.84
8.5	26,678,654	0	0.00000	1.00000	99.78
9.5	24,606,438	0	0.00000	1.00000	99.78
10.5	17,961,017	0	0.00000	1.00000	99.78
11.5	17,074,106	0	0.00000	1.00000	99.78
12.5	14,555,588	0	0.00000	1.00000	99.78
13.5	11,269,541	19,343	0.00172	0.99828	99.78
14.5	7,025,927	0	0.00000	1.00000	99.61
15.5	6,284,299	0	0.00000	1.00000	99.61
16.5	3,586,221	0	0.00000	1.00000	99.61
17.5	3,123,363	0	0.00000	1.00000	99.61
18.5	2,781,560	0	0.00000	1.00000	99.61
19.5	2,738,298	0	0.00000	1.00000	99.61
20.5	2,662,621	47,106	0.01769	0.98231	99.61
21.5	2,569,772	596,243	0.23202	0.76798	97.85
22.5	1,973,529	788,637	0.39961	0.60039	75.15
23.5	1,184,892	311,422	0.26283	0.73717	45.12
24.5	873,470	30,042	0.03439	0.96561	33.26
25.5	843,428	123,040	0.14588	0.85412	32.12
26.5	720,388	81,784	0.11353	0.88647	27.43

BC Hydro Power Authority

Account 57001 - Arrestor, Surge

Placement Band - 1981 - 2020 Experience Band - 2013 - 2020

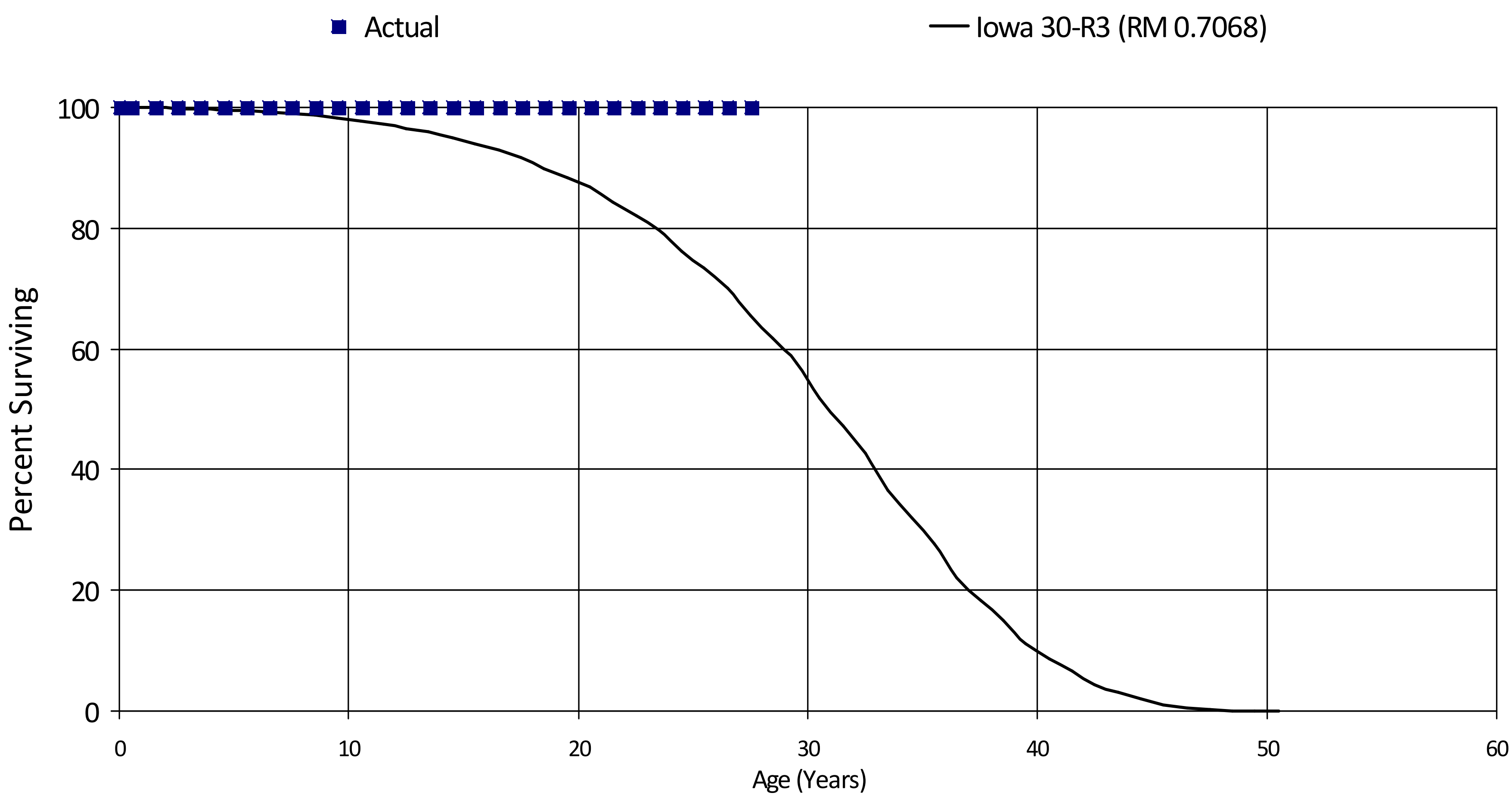
27.5	638,605	263,098	0.41199	0.58801	24.32
	Totals:	2,364,511			

BC Hydro Power Authority

Account 58001 - Converter

Placement Band - 1952 - 2020 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 58001 - Converter

Placement Band - 1952 - 2020 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	156,283	0	0.00000	1.00000	100.00
0.5	149,114	0	0.00000	1.00000	100.00
1.5	39,448	0	0.00000	1.00000	100.00
2.5	39,448	0	0.00000	1.00000	100.00
3.5	39,448	0	0.00000	1.00000	100.00
4.5	39,448	0	0.00000	1.00000	100.00
5.5	39,448	0	0.00000	1.00000	100.00
6.5	39,448	0	0.00000	1.00000	100.00
7.5	39,448	0	0.00000	1.00000	100.00
8.5	39,448	0	0.00000	1.00000	100.00
9.5	39,448	0	0.00000	1.00000	100.00
10.5	39,448	0	0.00000	1.00000	100.00
11.5	39,448	0	0.00000	1.00000	100.00
12.5	39,448	0	0.00000	1.00000	100.00
13.5	39,448	0	0.00000	1.00000	100.00
14.5	39,448	0	0.00000	1.00000	100.00
15.5	39,448	0	0.00000	1.00000	100.00
16.5	39,448	0	0.00000	1.00000	100.00
17.5	39,448	0	0.00000	1.00000	100.00
18.5	39,448	0	0.00000	1.00000	100.00
19.5	39,448	0	0.00000	1.00000	100.00
20.5	32,785	0	0.00000	1.00000	100.00
21.5	32,785	0	0.00000	1.00000	100.00
22.5	32,785	0	0.00000	1.00000	100.00
23.5	32,785	0	0.00000	1.00000	100.00
24.5	32,785	0	0.00000	1.00000	100.00
25.5	4,447	0	0.00000	1.00000	100.00
26.5	4,447	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 58001 - Converter

Placement Band - 1952 - 2020   Experience Band - 2020 - 2020

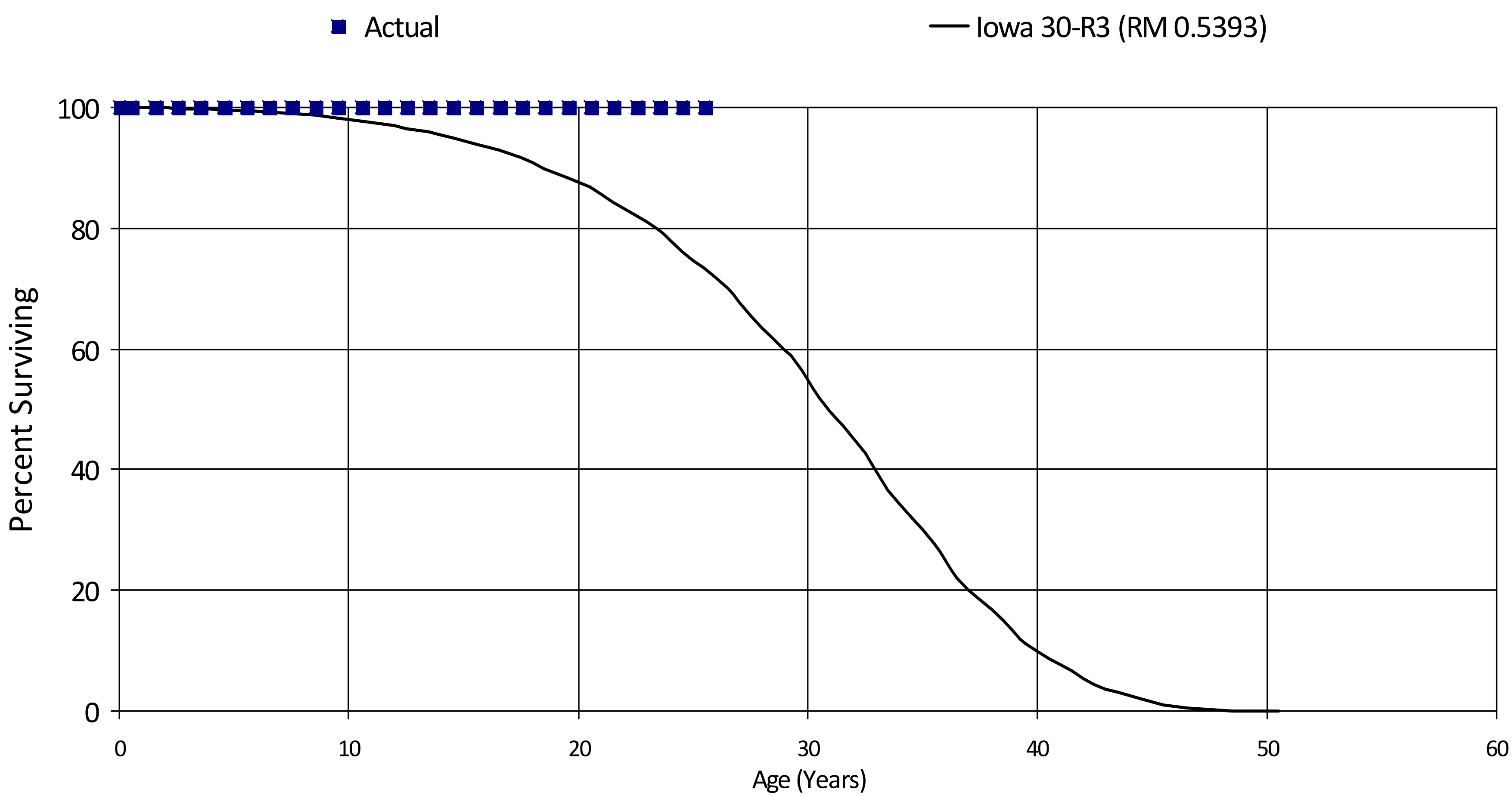
27.5	1,613	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 58002 - Inverter

Placement Band - 1968 - 2017   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 58002 - Inverter

Placement Band - 1968 - 2017   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

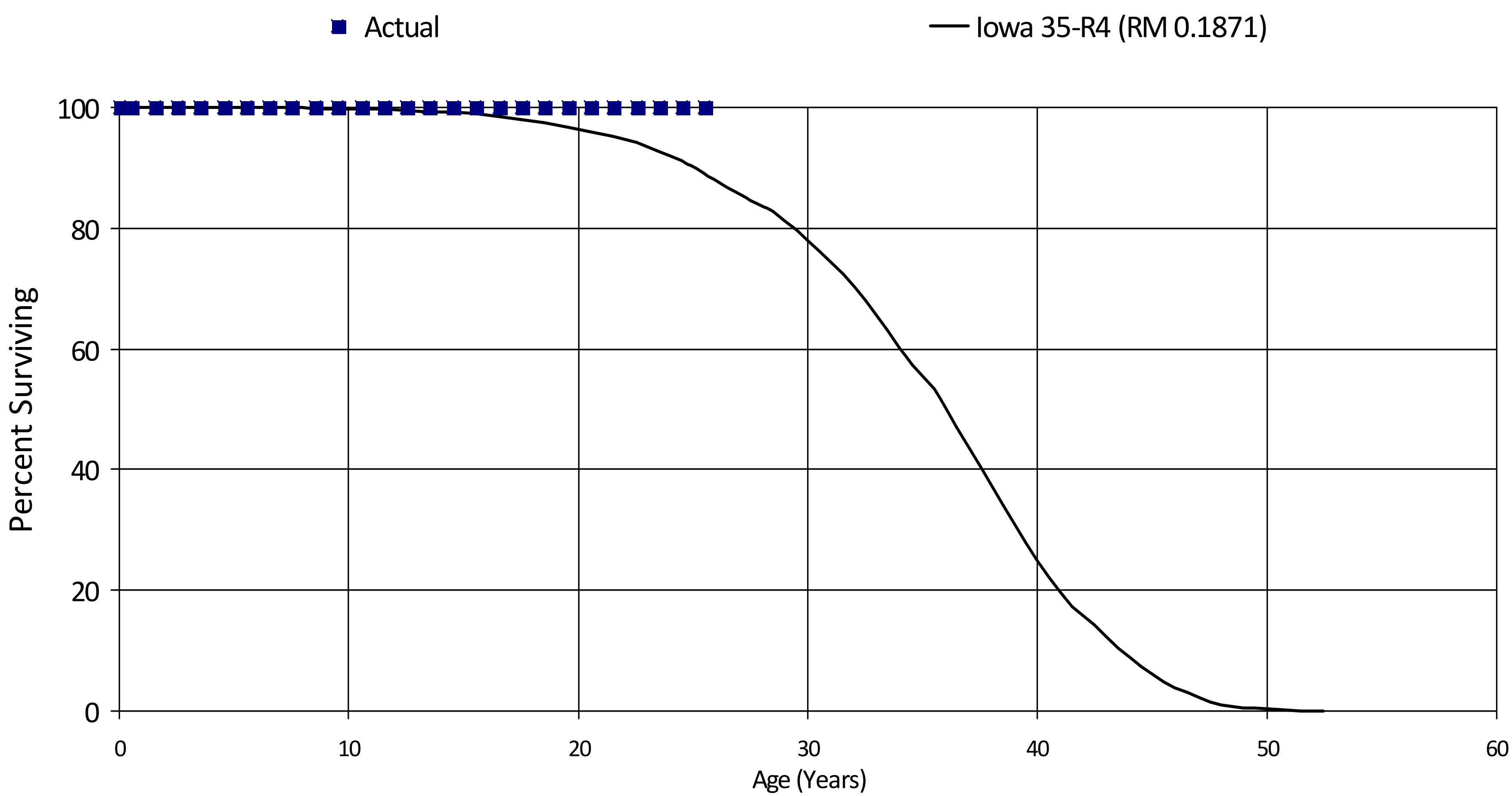
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,129,037	0	0.00000	1.00000	100.00
0.5	1,129,037	0	0.00000	1.00000	100.00
1.5	1,129,037	0	0.00000	1.00000	100.00
2.5	1,129,037	0	0.00000	1.00000	100.00
3.5	990,799	0	0.00000	1.00000	100.00
4.5	806,894	0	0.00000	1.00000	100.00
5.5	806,894	0	0.00000	1.00000	100.00
6.5	806,894	0	0.00000	1.00000	100.00
7.5	806,894	0	0.00000	1.00000	100.00
8.5	232,889	0	0.00000	1.00000	100.00
9.5	232,889	0	0.00000	1.00000	100.00
10.5	232,889	0	0.00000	1.00000	100.00
11.5	232,889	0	0.00000	1.00000	100.00
12.5	232,889	0	0.00000	1.00000	100.00
13.5	181,124	0	0.00000	1.00000	100.00
14.5	181,124	0	0.00000	1.00000	100.00
15.5	181,124	0	0.00000	1.00000	100.00
16.5	181,124	0	0.00000	1.00000	100.00
17.5	181,124	0	0.00000	1.00000	100.00
18.5	181,124	0	0.00000	1.00000	100.00
19.5	181,124	0	0.00000	1.00000	100.00
20.5	181,124	0	0.00000	1.00000	100.00
21.5	172,828	0	0.00000	1.00000	100.00
22.5	35,758	0	0.00000	1.00000	100.00
23.5	35,758	0	0.00000	1.00000	100.00
24.5	35,758	0	0.00000	1.00000	100.00
25.5	35,758	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 58101 - Var Compensator, Static

Placement Band - 1994 - 2009   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 58101 - Var Compensator, Static

Placement Band - 1994 - 2009   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

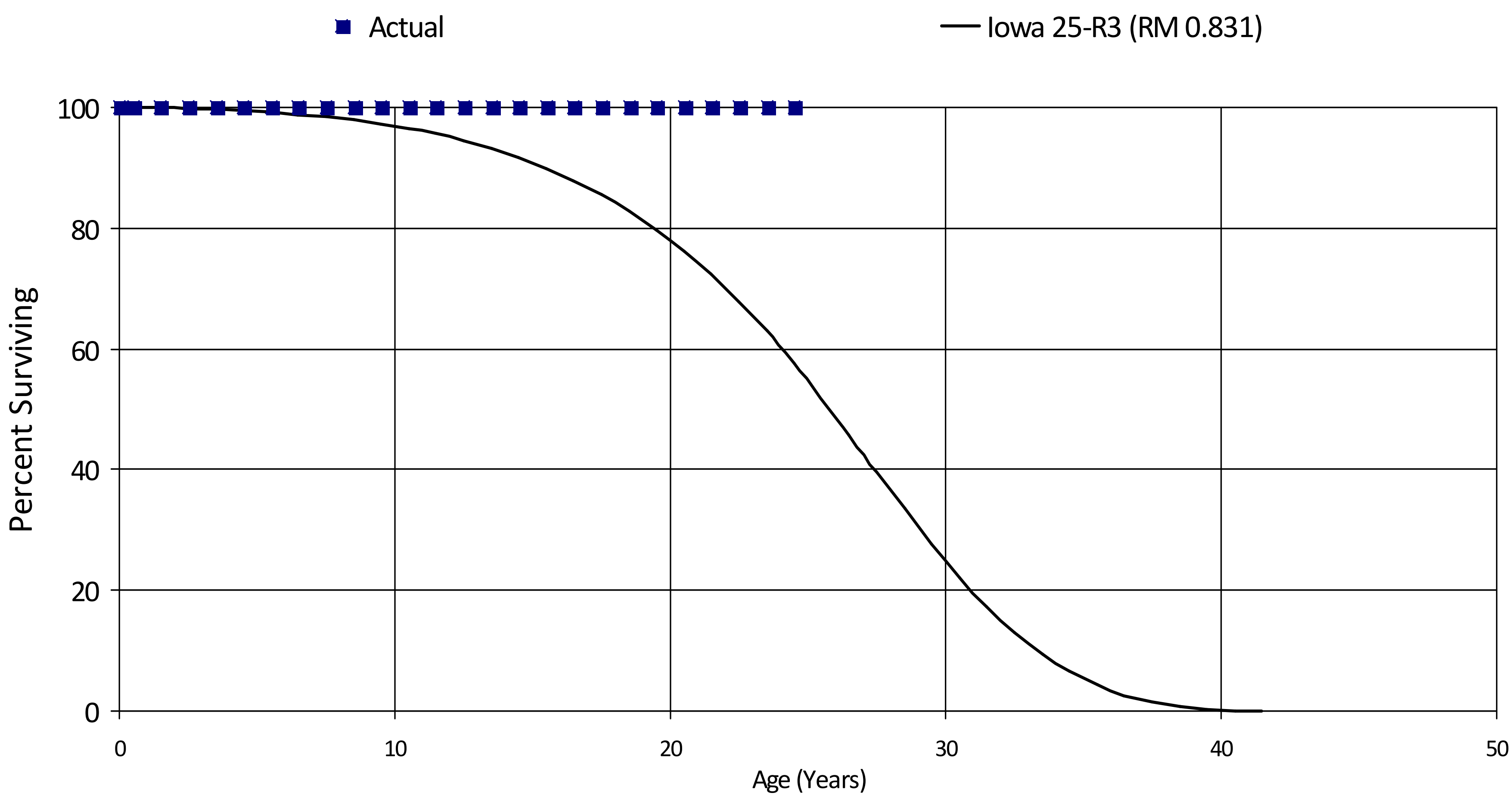
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	12,484,909	0	0.00000	1.00000	100.00
0.5	12,484,909	0	0.00000	1.00000	100.00
1.5	12,484,909	0	0.00000	1.00000	100.00
2.5	12,484,909	0	0.00000	1.00000	100.00
3.5	12,484,909	0	0.00000	1.00000	100.00
4.5	12,484,909	0	0.00000	1.00000	100.00
5.5	12,484,909	0	0.00000	1.00000	100.00
6.5	12,484,909	0	0.00000	1.00000	100.00
7.5	12,484,909	0	0.00000	1.00000	100.00
8.5	12,484,909	0	0.00000	1.00000	100.00
9.5	12,484,909	0	0.00000	1.00000	100.00
10.5	12,484,909	0	0.00000	1.00000	100.00
11.5	11,315,598	0	0.00000	1.00000	100.00
12.5	11,315,598	0	0.00000	1.00000	100.00
13.5	2,964,782	0	0.00000	1.00000	100.00
14.5	2,964,782	0	0.00000	1.00000	100.00
15.5	2,964,782	0	0.00000	1.00000	100.00
16.5	2,964,782	0	0.00000	1.00000	100.00
17.5	1,599,314	0	0.00000	1.00000	100.00
18.5	1,599,314	0	0.00000	1.00000	100.00
19.5	1,599,314	0	0.00000	1.00000	100.00
20.5	1,599,314	0	0.00000	1.00000	100.00
21.5	1,599,314	0	0.00000	1.00000	100.00
22.5	1,599,314	0	0.00000	1.00000	100.00
23.5	1,599,314	0	0.00000	1.00000	100.00
24.5	1,599,314	0	0.00000	1.00000	100.00
25.5	1,599,314	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 58201 - Resistor, Anode Damping

Placement Band - 1995 - 2016   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 58201 - Resistor, Anode Damping

Placement Band - 1995 - 2016   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

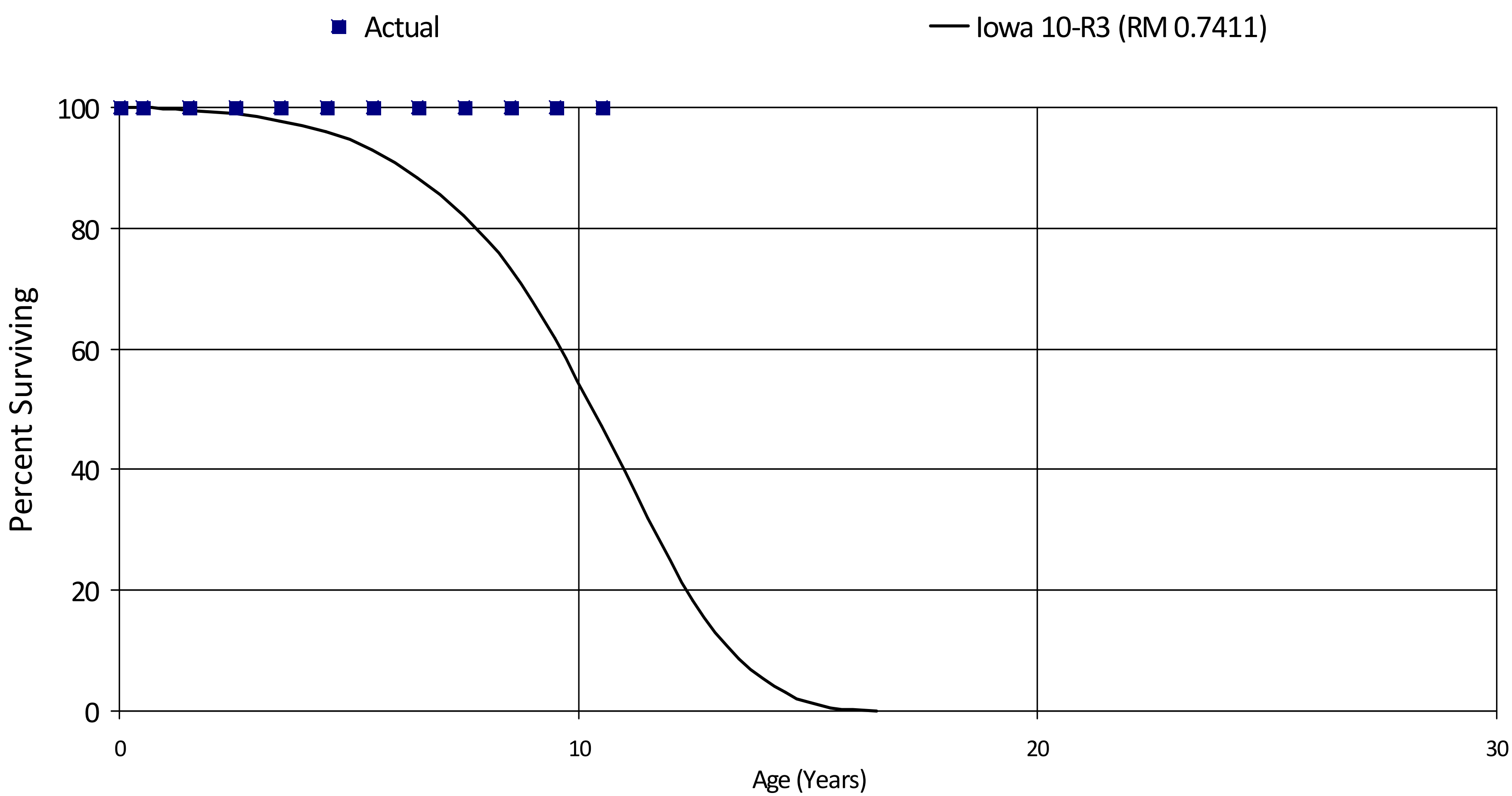
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	198,236	0	0.00000	1.00000	100.00
0.5	198,236	0	0.00000	1.00000	100.00
1.5	198,236	0	0.00000	1.00000	100.00
2.5	198,236	0	0.00000	1.00000	100.00
3.5	198,236	0	0.00000	1.00000	100.00
4.5	148,435	0	0.00000	1.00000	100.00
5.5	148,435	0	0.00000	1.00000	100.00
6.5	148,435	0	0.00000	1.00000	100.00
7.5	66,927	0	0.00000	1.00000	100.00
8.5	66,927	0	0.00000	1.00000	100.00
9.5	66,927	0	0.00000	1.00000	100.00
10.5	66,927	0	0.00000	1.00000	100.00
11.5	66,927	0	0.00000	1.00000	100.00
12.5	66,927	0	0.00000	1.00000	100.00
13.5	66,927	0	0.00000	1.00000	100.00
14.5	66,927	0	0.00000	1.00000	100.00
15.5	66,927	0	0.00000	1.00000	100.00
16.5	66,927	0	0.00000	1.00000	100.00
17.5	66,927	0	0.00000	1.00000	100.00
18.5	66,927	0	0.00000	1.00000	100.00
19.5	66,927	0	0.00000	1.00000	100.00
20.5	66,927	0	0.00000	1.00000	100.00
21.5	66,927	0	0.00000	1.00000	100.00
22.5	66,927	0	0.00000	1.00000	100.00
23.5	66,927	0	0.00000	1.00000	100.00
24.5	66,927	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 58901 - Power Supply, Solar Panel

Placement Band - 2002 - 2017   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 58901 - Power Supply, Solar Panel

Placement Band - 2002 - 2017   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

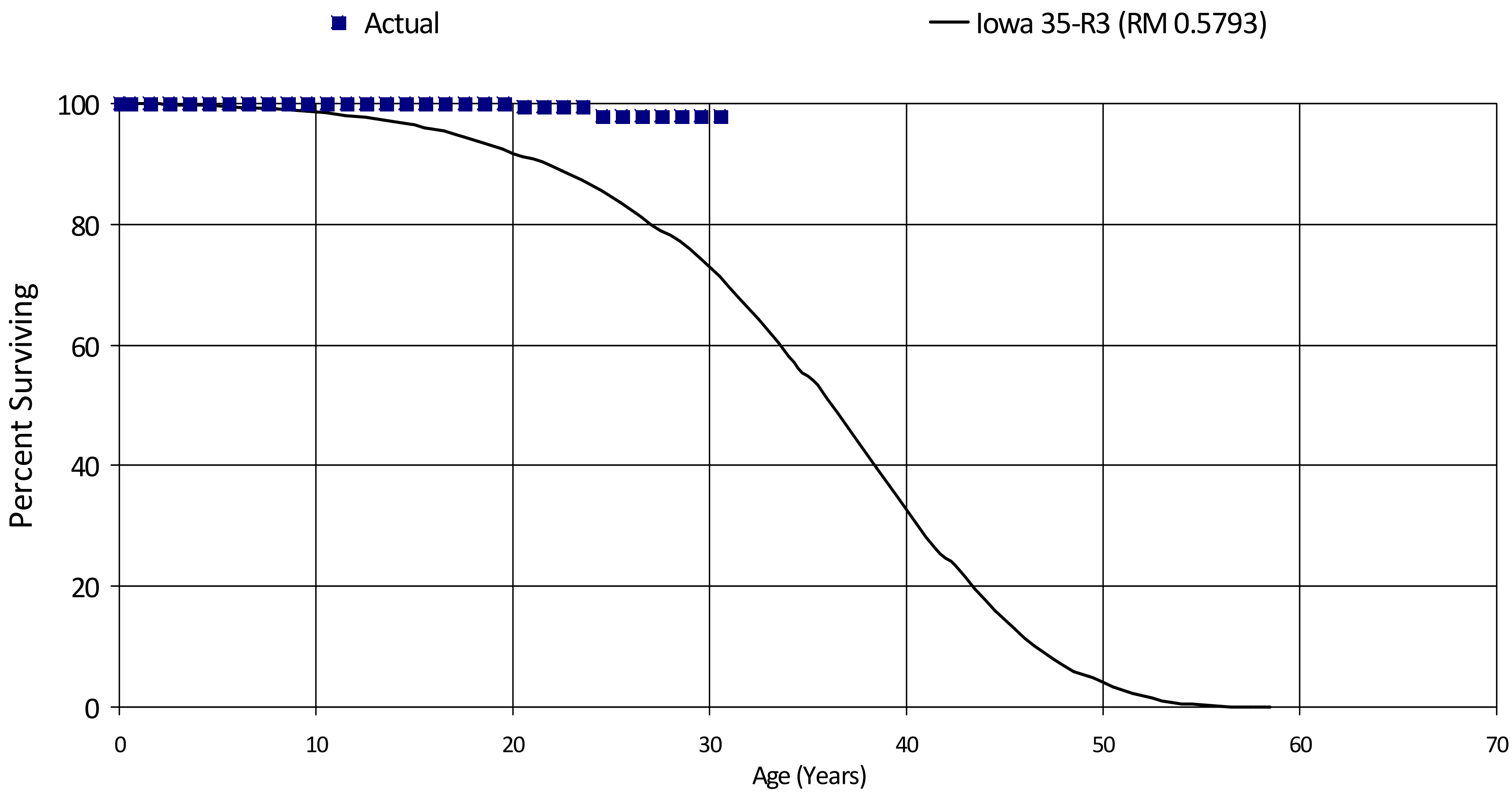
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,899,036	0	0.00000	1.00000	100.00
0.5	1,899,036	0	0.00000	1.00000	100.00
1.5	1,899,036	0	0.00000	1.00000	100.00
2.5	1,899,036	0	0.00000	1.00000	100.00
3.5	1,714,367	0	0.00000	1.00000	100.00
4.5	1,714,367	0	0.00000	1.00000	100.00
5.5	1,356,856	0	0.00000	1.00000	100.00
6.5	971,686	0	0.00000	1.00000	100.00
7.5	703,562	0	0.00000	1.00000	100.00
8.5	460,862	0	0.00000	1.00000	100.00
9.5	314,607	0	0.00000	1.00000	100.00
10.5	113,349	29,128	0.25698	0.74302	100.00
	Totals:	29,128			

BC Hydro Power Authority

Account 59101 - Regulator, Feeder Circuit

Placement Band - 1939 - 2019   Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 59101 - Regulator, Feeder Circuit

Placement Band - 1939 - 2019   Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	20,624,360	0	0.00000	1.00000	100.00
0.5	20,624,360	0	0.00000	1.00000	100.00
1.5	19,894,642	0	0.00000	1.00000	100.00
2.5	19,072,574	0	0.00000	1.00000	100.00
3.5	16,499,727	0	0.00000	1.00000	100.00
4.5	12,379,520	0	0.00000	1.00000	100.00
5.5	12,379,520	0	0.00000	1.00000	100.00
6.5	10,531,577	0	0.00000	1.00000	100.00
7.5	10,522,047	0	0.00000	1.00000	100.00
8.5	7,100,557	0	0.00000	1.00000	100.00
9.5	3,627,590	0	0.00000	1.00000	100.00
10.5	2,625,563	0	0.00000	1.00000	100.00
11.5	2,605,956	0	0.00000	1.00000	100.00
12.5	1,237,483	0	0.00000	1.00000	100.00
13.5	1,086,529	0	0.00000	1.00000	100.00
14.5	1,044,033	0	0.00000	1.00000	100.00
15.5	1,013,151	0	0.00000	1.00000	100.00
16.5	852,466	0	0.00000	1.00000	100.00
17.5	384,391	0	0.00000	1.00000	100.00
18.5	384,391	0	0.00000	1.00000	100.00
19.5	384,391	1,864	0.00485	0.99515	100.00
20.5	353,273	0	0.00000	1.00000	99.52
21.5	353,273	0	0.00000	1.00000	99.52
22.5	353,273	0	0.00000	1.00000	99.52
23.5	353,273	5,223	0.01478	0.98522	99.52
24.5	348,050	0	0.00000	1.00000	98.05
25.5	312,923	0	0.00000	1.00000	98.05
26.5	234,301	0	0.00000	1.00000	98.05

BC Hydro Power Authority

Account 59101 - Regulator, Feeder Circuit

Placement Band - 1939 - 2019   Experience Band - 2014 - 2020

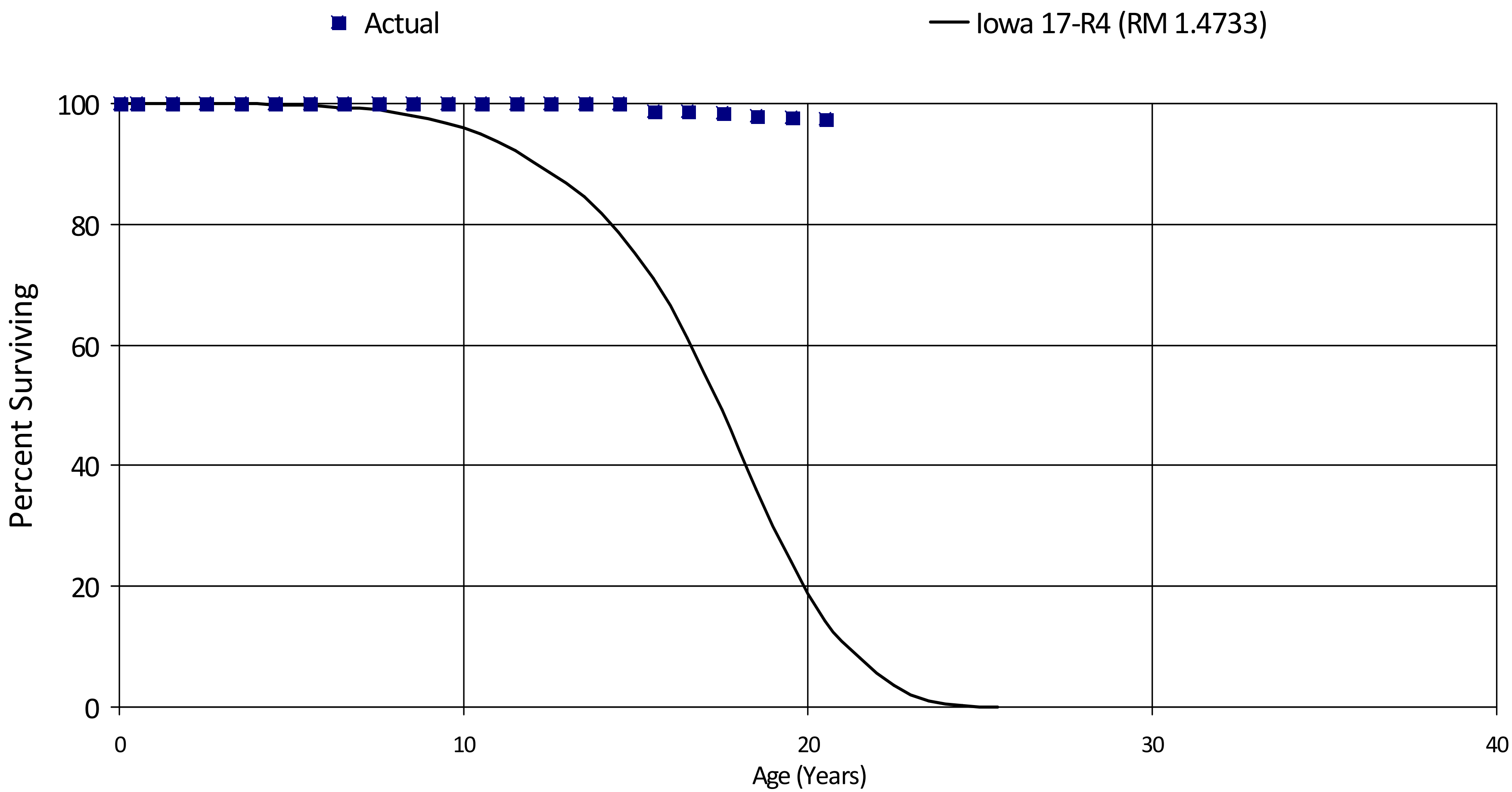
27.5	234,301	0	0.00000	1.00000	98.05
28.5	223,325	0	0.00000	1.00000	98.05
29.5	217,528	0	0.00000	1.00000	98.05
30.5	216,293	1,197	0.00553	0.99447	98.05
	Totals:	8,284			

BC Hydro Power Authority

Account 59201 - Charger System, Battery

Placement Band - 1992 - 2020 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 59201 - Charger System, Battery

Placement Band - 1992 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

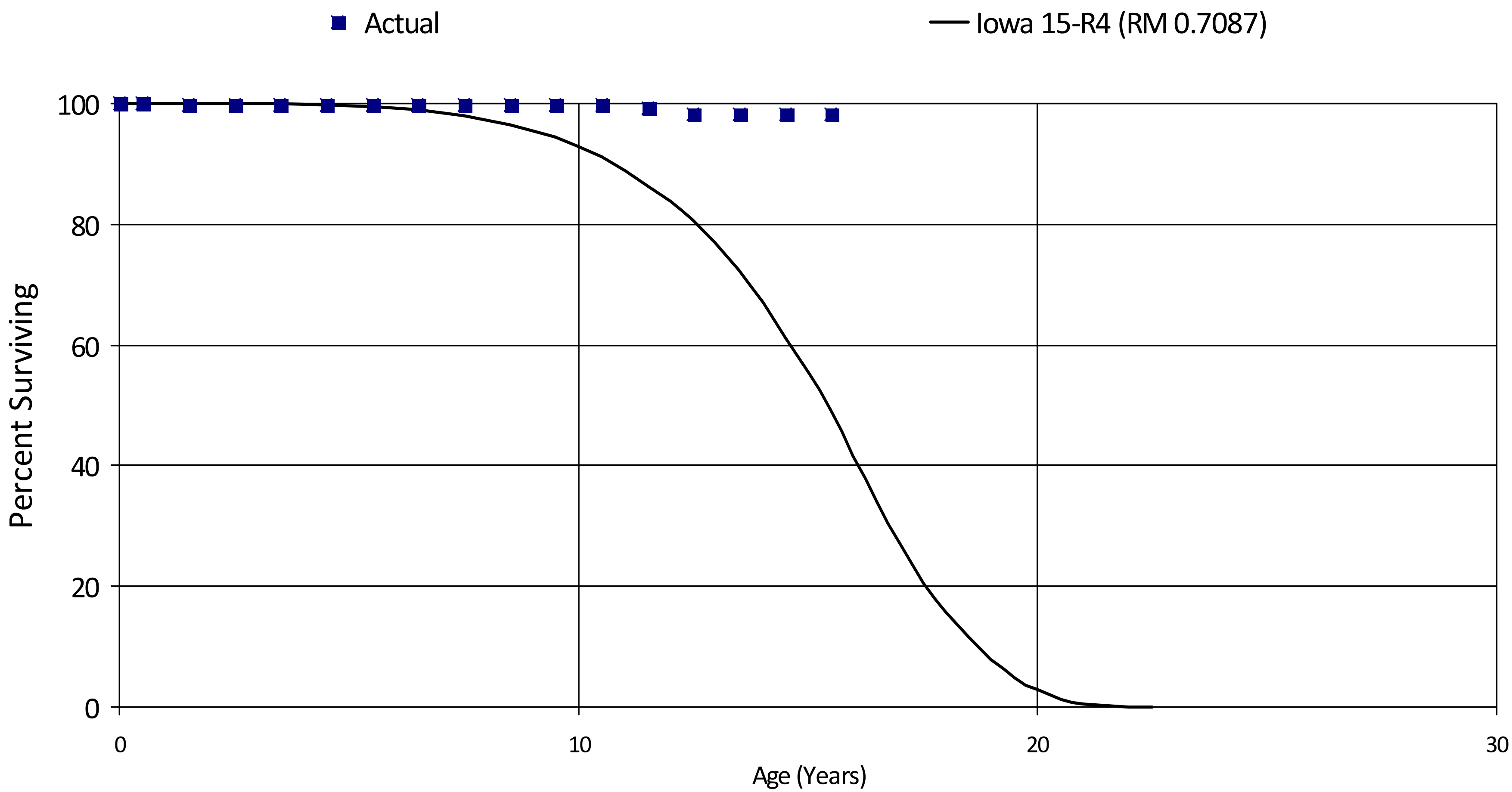
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	24,404,336	0	0.00000	1.00000	100.00
0.5	22,432,892	0	0.00000	1.00000	100.00
1.5	21,204,221	0	0.00000	1.00000	100.00
2.5	19,328,018	0	0.00000	1.00000	100.00
3.5	17,632,025	0	0.00000	1.00000	100.00
4.5	13,777,941	0	0.00000	1.00000	100.00
5.5	11,677,584	0	0.00000	1.00000	100.00
6.5	11,302,035	0	0.00000	1.00000	100.00
7.5	9,786,890	0	0.00000	1.00000	100.00
8.5	6,241,823	0	0.00000	1.00000	100.00
9.5	5,898,297	0	0.00000	1.00000	100.00
10.5	4,983,370	1,171	0.00023	0.99977	100.00
11.5	3,941,424	0	0.00000	1.00000	99.98
12.5	3,201,383	672	0.00021	0.99979	99.98
13.5	2,842,563	1,318	0.00046	0.99954	99.96
14.5	2,332,970	28,277	0.01212	0.98788	99.91
15.5	1,777,573	0	0.00000	1.00000	98.70
16.5	1,287,458	3,013	0.00234	0.99766	98.70
17.5	1,132,230	6,963	0.00615	0.99385	98.47
18.5	1,053,809	1,776	0.00169	0.99831	97.86
19.5	341,431	866	0.00254	0.99746	97.69
20.5	271,469	204,755	0.75425	0.24575	97.44
	Totals:	248,811			

BC Hydro Power Authority

Account 59301 - Storage Batteries, Bank

Placement Band - 1997 - 2020 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 59301 - Storage Batteries, Bank

Placement Band - 1997 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

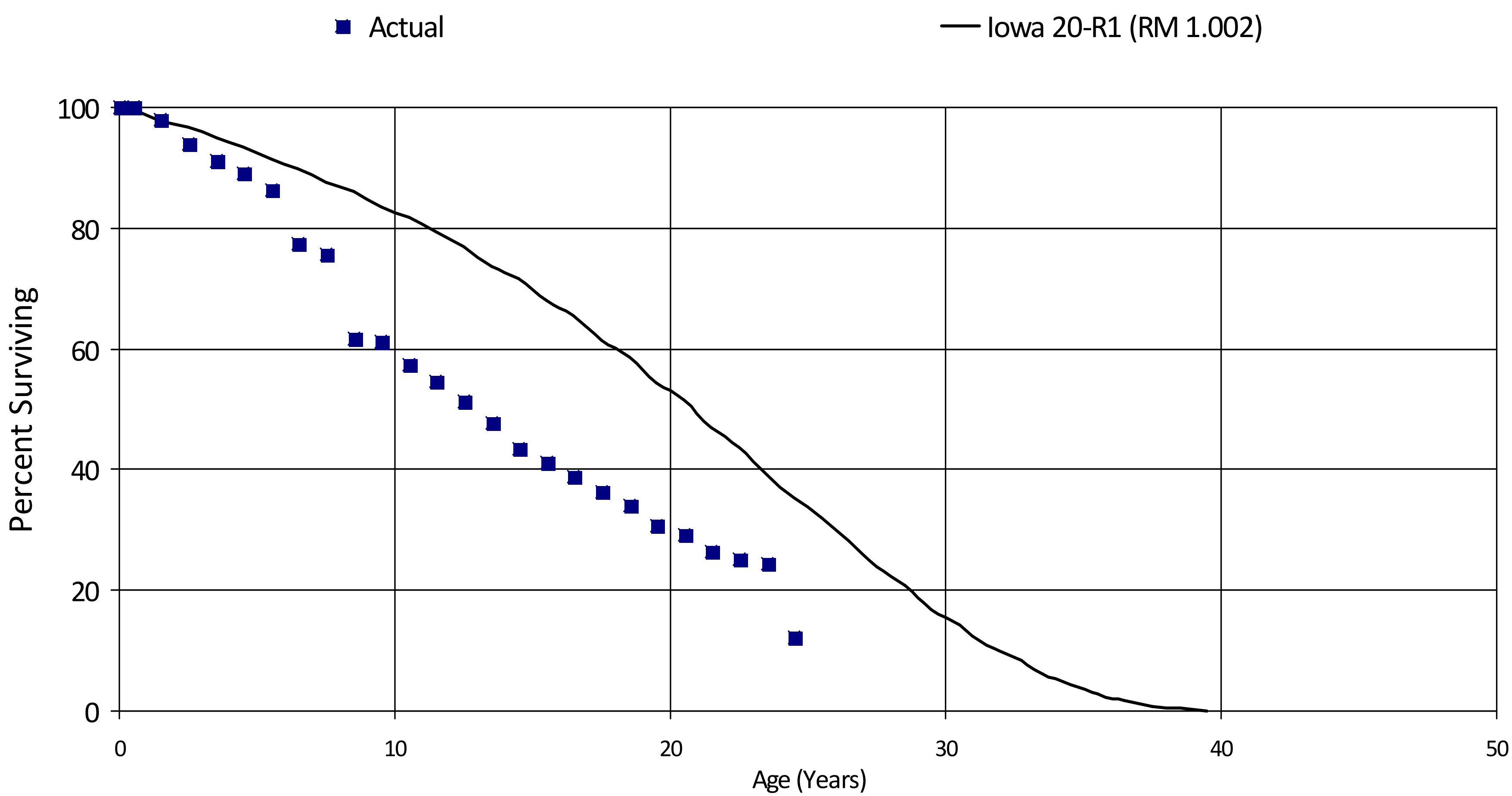
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	34,421,931	0	0.00000	1.00000	100.00
0.5	33,848,572	57,236	0.00169	0.99831	100.00
1.5	32,814,783	0	0.00000	1.00000	99.83
2.5	17,483,285	0	0.00000	1.00000	99.83
3.5	13,531,530	0	0.00000	1.00000	99.83
4.5	13,151,540	0	0.00000	1.00000	99.83
5.5	11,813,388	0	0.00000	1.00000	99.83
6.5	11,165,281	0	0.00000	1.00000	99.83
7.5	9,381,661	0	0.00000	1.00000	99.83
8.5	6,397,945	0	0.00000	1.00000	99.83
9.5	5,856,393	2,179	0.00037	0.99963	99.83
10.5	5,016,729	33,060	0.00659	0.99341	99.79
11.5	3,453,552	33,535	0.00971	0.99029	99.13
12.5	2,550,112	0	0.00000	1.00000	98.17
13.5	2,161,977	830	0.00038	0.99962	98.17
14.5	1,601,130	0	0.00000	1.00000	98.13
15.5	825,792	0	0.00000	1.00000	98.13
	Totals:	126,840			

BC Hydro Power Authority

Account 59401 - Meters, Billing, Distribution

Placement Band - 1986 - 2020 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 59401 - Meters, Billing, Distribution

Placement Band - 1986 - 2020 Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

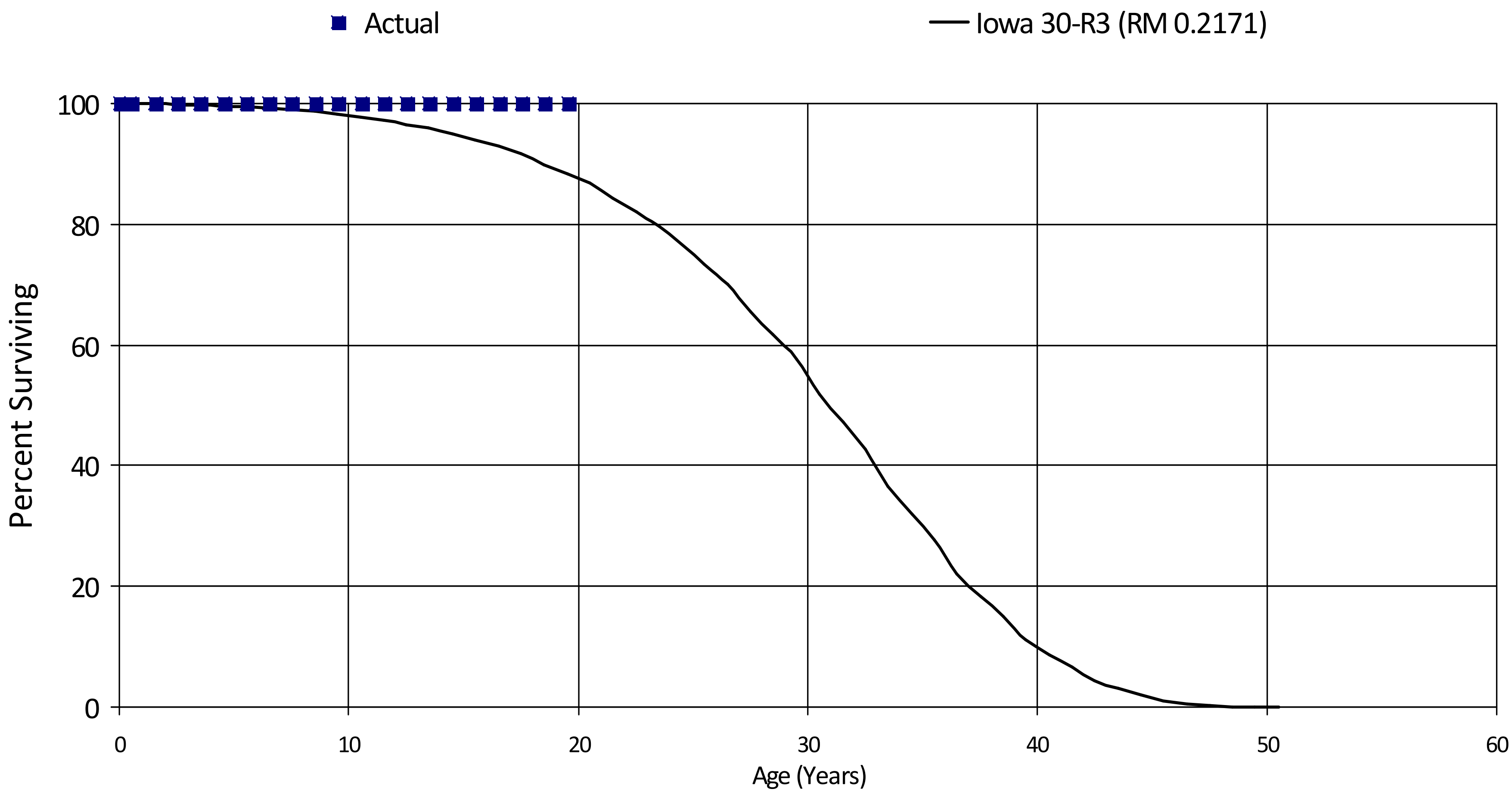
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	134,454,286	0	0.00000	1.00000	100.00
0.5	134,204,352	2,771,619	0.02065	0.97935	100.00
1.5	130,383,560	5,439,399	0.04172	0.95828	97.93
2.5	122,286,900	3,666,293	0.02998	0.97002	93.84
3.5	115,677,664	2,312,371	0.01999	0.98001	91.03
4.5	110,103,885	3,443,330	0.03127	0.96873	89.21
5.5	105,825,997	10,975,019	0.10371	0.89629	86.42
6.5	90,895,164	2,015,686	0.02218	0.97782	77.46
7.5	84,236,838	15,782,775	0.18736	0.81264	75.74
8.5	62,148,104	350,817	0.00564	0.99436	61.55
9.5	59,324,929	3,795,034	0.06397	0.93603	61.20
10.5	53,903,217	2,519,299	0.04674	0.95326	57.29
11.5	50,365,975	3,153,772	0.06262	0.93738	54.61
12.5	45,674,384	3,168,026	0.06936	0.93064	51.19
13.5	37,602,030	3,345,580	0.08897	0.91103	47.64
14.5	33,356,884	1,816,147	0.05445	0.94555	43.40
15.5	24,322,173	1,383,003	0.05686	0.94314	41.04
16.5	22,790,696	1,396,781	0.06129	0.93871	38.71
17.5	19,705,417	1,330,341	0.06751	0.93249	36.34
18.5	17,271,080	1,582,473	0.09163	0.90837	33.89
19.5	14,327,915	708,469	0.04945	0.95055	30.78
20.5	12,286,478	1,200,712	0.09773	0.90227	29.26
21.5	9,722,622	464,561	0.04778	0.95222	26.40
22.5	8,548,806	266,216	0.03114	0.96886	25.14
23.5	7,772,930	3,869,307	0.49779	0.50221	24.36
24.5	3,741,107	2,673,145	0.71453	0.28547	12.23
	Totals:	79,430,175			

BC Hydro Power Authority

Account 59402 - Meters, Transmission

Placement Band - 1996 - 2019 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 59402 - Meters, Transmission

Placement Band - 1996 - 2019   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

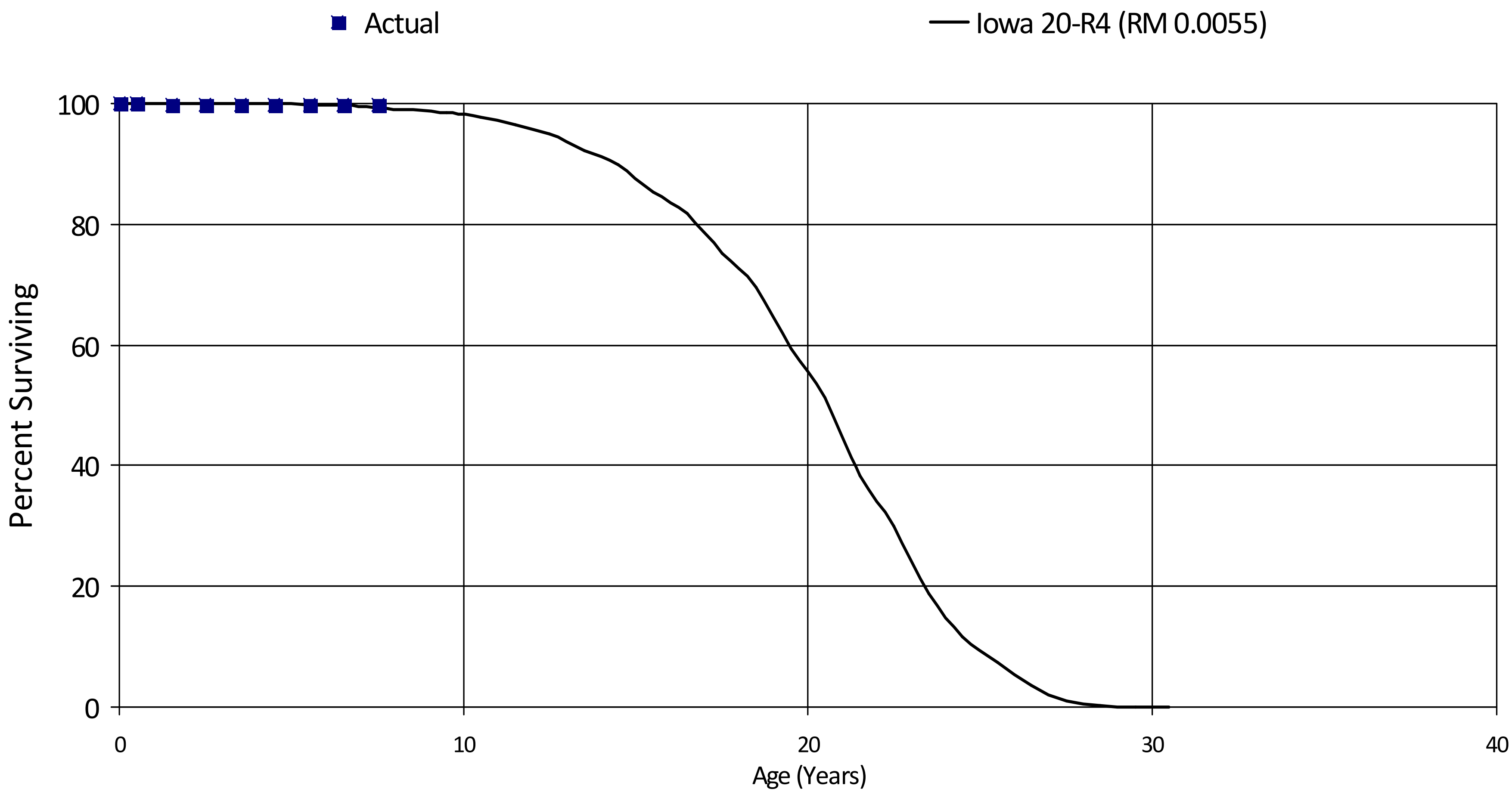
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	7,721,395	0	0.00000	1.00000	100.00
0.5	7,721,395	0	0.00000	1.00000	100.00
1.5	6,823,574	0	0.00000	1.00000	100.00
2.5	5,036,317	0	0.00000	1.00000	100.00
3.5	3,713,613	0	0.00000	1.00000	100.00
4.5	1,984,082	0	0.00000	1.00000	100.00
5.5	1,632,647	0	0.00000	1.00000	100.00
6.5	504,322	0	0.00000	1.00000	100.00
7.5	388,896	0	0.00000	1.00000	100.00
8.5	388,896	0	0.00000	1.00000	100.00
9.5	333,911	0	0.00000	1.00000	100.00
10.5	333,911	0	0.00000	1.00000	100.00
11.5	333,911	0	0.00000	1.00000	100.00
12.5	333,911	0	0.00000	1.00000	100.00
13.5	333,911	0	0.00000	1.00000	100.00
14.5	325,981	0	0.00000	1.00000	100.00
15.5	325,981	0	0.00000	1.00000	100.00
16.5	294,493	0	0.00000	1.00000	100.00
17.5	160,600	0	0.00000	1.00000	100.00
18.5	113,200	0	0.00000	1.00000	100.00
19.5	98,828	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 59403 - Automated Meters, Distribution

Placement Band - 2012 - 2020 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 59403 - Automated Meters, Distribution

Placement Band - 2012 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

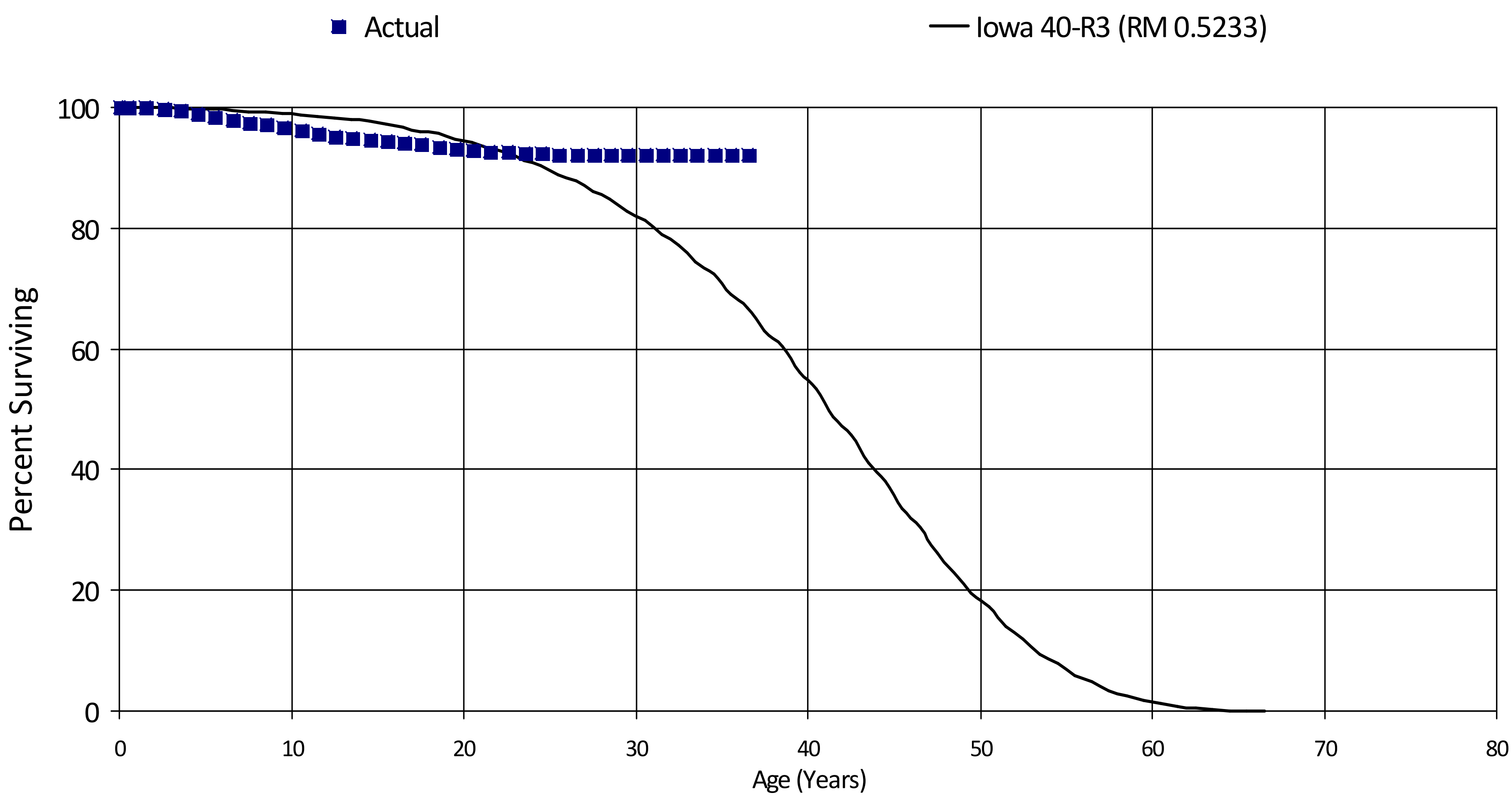
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	397,742,177	0	0.00000	1.00000	100.00
0.5	397,742,103	746,035	0.00188	0.99812	100.00
1.5	392,139,104	0	0.00000	1.00000	99.81
2.5	385,818,443	0	0.00000	1.00000	99.81
3.5	382,800,679	0	0.00000	1.00000	99.81
4.5	351,469,674	0	0.00000	1.00000	99.81
5.5	304,341,553	0	0.00000	1.00000	99.81
6.5	296,431,864	0	0.00000	1.00000	99.81
7.5	267,605,975	0	0.00000	1.00000	99.81
	Totals:	746,035			

BC Hydro Power Authority

Account 59501 - Street Lights, Distribution, Owned

Placement Band - 1972 - 2020 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 59501 - Street Lights, Distribution, Owned

Placement Band - 1972 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	31,281,520	0	0.00000	1.00000	100.00
0.5	30,541,588	13,592	0.00045	0.99955	100.00
1.5	28,441,443	45,327	0.00159	0.99841	99.96
2.5	26,341,281	99,735	0.00379	0.99621	99.80
3.5	24,578,430	127,155	0.00517	0.99483	99.42
4.5	23,076,083	85,233	0.00369	0.99631	98.91
5.5	22,126,673	117,569	0.00531	0.99469	98.55
6.5	20,851,370	105,490	0.00506	0.99494	98.03
7.5	19,981,693	81,470	0.00408	0.99592	97.53
8.5	18,055,765	93,271	0.00517	0.99483	97.13
9.5	16,967,170	75,962	0.00448	0.99552	96.63
10.5	16,052,898	83,908	0.00523	0.99477	96.20
11.5	15,153,189	76,305	0.00504	0.99496	95.70
12.5	14,160,194	52,023	0.00367	0.99633	95.22
13.5	13,377,846	31,361	0.00234	0.99766	94.87
14.5	12,708,772	31,424	0.00247	0.99753	94.65
15.5	12,164,890	39,342	0.00323	0.99677	94.42
16.5	11,585,899	34,492	0.00298	0.99702	94.12
17.5	10,757,431	45,224	0.00420	0.99580	93.84
18.5	10,280,453	31,560	0.00307	0.99693	93.45
19.5	9,771,389	28,636	0.00293	0.99707	93.16
20.5	9,331,674	14,162	0.00152	0.99848	92.89
21.5	8,789,288	12,797	0.00146	0.99854	92.75
22.5	8,429,715	10,390	0.00123	0.99877	92.61
23.5	7,902,047	17,083	0.00216	0.99784	92.50
24.5	7,244,534	6,683	0.00092	0.99908	92.30
25.5	6,579,362	0	0.00000	1.00000	92.22
26.5	5,345,620	0	0.00000	1.00000	92.22

BC Hydro Power Authority

Account 59501 - Street Lights, Distribution, Owned

Placement Band - 1972 - 2020 Experience Band - 2013 - 2020

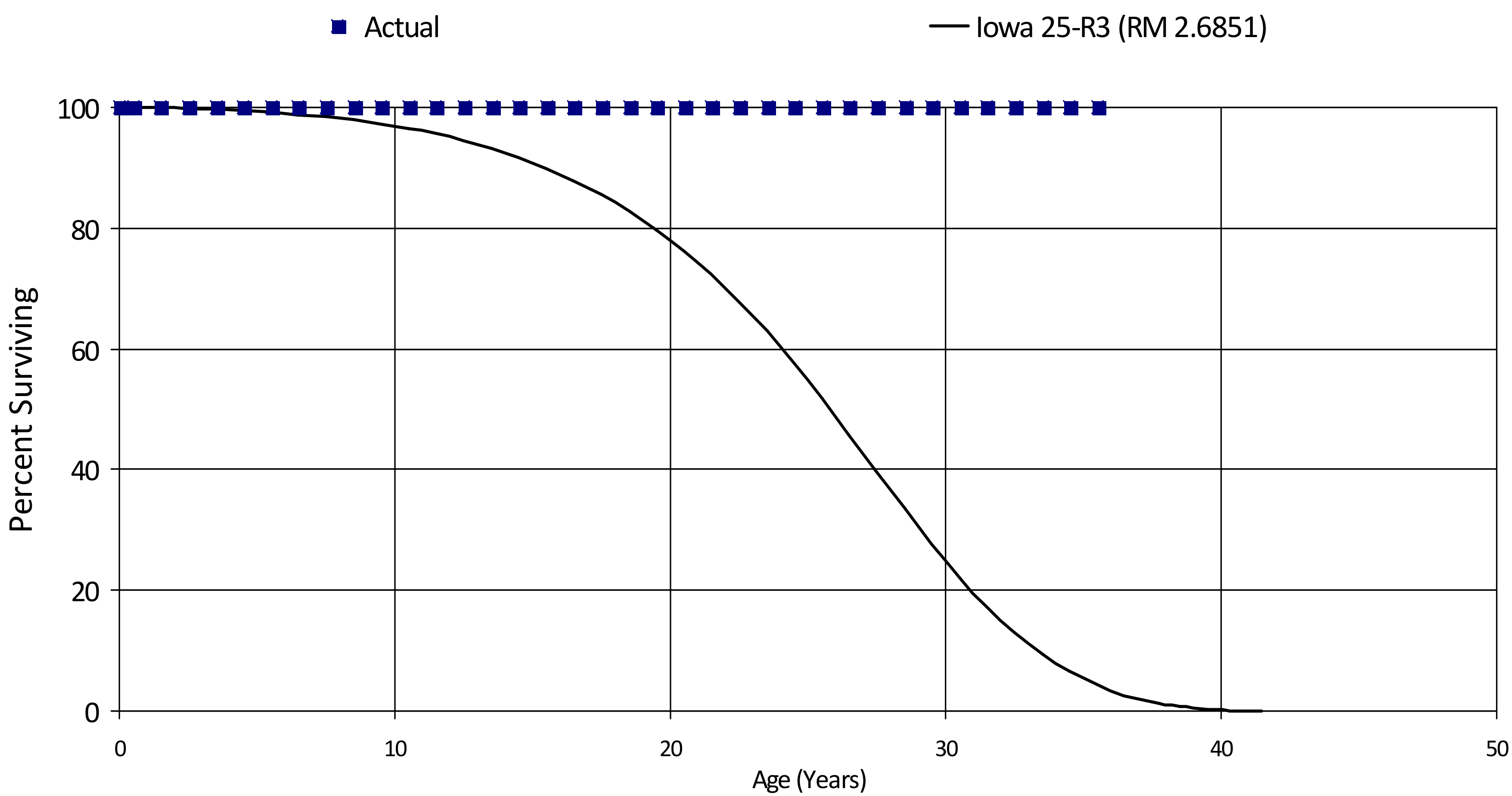
27.5	3,572,573	0	0.00000	1.00000	92.22
28.5	2,250,876	0	0.00000	1.00000	92.22
29.5	1,976,387	0	0.00000	1.00000	92.22
30.5	1,742,139	0	0.00000	1.00000	92.22
31.5	1,676,457	0	0.00000	1.00000	92.22
32.5	1,031,888	0	0.00000	1.00000	92.22
33.5	826,377	0	0.00000	1.00000	92.22
34.5	632,159	0	0.00000	1.00000	92.22
35.5	562,829	0	0.00000	1.00000	92.22
36.5	348,048	0	0.00000	1.00000	92.22
	Totals:	1,360,194			

BC Hydro Power Authority

Account 59601 - Metering, Dcp, Trolleys

Placement Band - 1981 - 2010   Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 59601 - Metering, Dcp, Trolleys

Placement Band - 1981 - 2010   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,676,836	0	0.00000	1.00000	100.00
0.5	1,676,836	0	0.00000	1.00000	100.00
1.5	1,676,836	0	0.00000	1.00000	100.00
2.5	1,676,836	0	0.00000	1.00000	100.00
3.5	1,676,836	0	0.00000	1.00000	100.00
4.5	1,676,836	0	0.00000	1.00000	100.00
5.5	1,676,836	0	0.00000	1.00000	100.00
6.5	1,676,836	0	0.00000	1.00000	100.00
7.5	1,676,836	0	0.00000	1.00000	100.00
8.5	1,676,836	0	0.00000	1.00000	100.00
9.5	1,676,836	0	0.00000	1.00000	100.00
10.5	918,063	0	0.00000	1.00000	100.00
11.5	918,063	0	0.00000	1.00000	100.00
12.5	918,063	0	0.00000	1.00000	100.00
13.5	918,063	0	0.00000	1.00000	100.00
14.5	918,063	0	0.00000	1.00000	100.00
15.5	893,627	0	0.00000	1.00000	100.00
16.5	893,627	0	0.00000	1.00000	100.00
17.5	780,527	0	0.00000	1.00000	100.00
18.5	780,527	0	0.00000	1.00000	100.00
19.5	780,527	0	0.00000	1.00000	100.00
20.5	780,527	0	0.00000	1.00000	100.00
21.5	780,527	0	0.00000	1.00000	100.00
22.5	777,011	0	0.00000	1.00000	100.00
23.5	770,129	0	0.00000	1.00000	100.00
24.5	728,818	0	0.00000	1.00000	100.00
25.5	702,699	0	0.00000	1.00000	100.00
26.5	424,228	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 59601 - Metering, Dcp, Trolleys

Placement Band - 1981 - 2010   Experience Band - 2017 - 2020

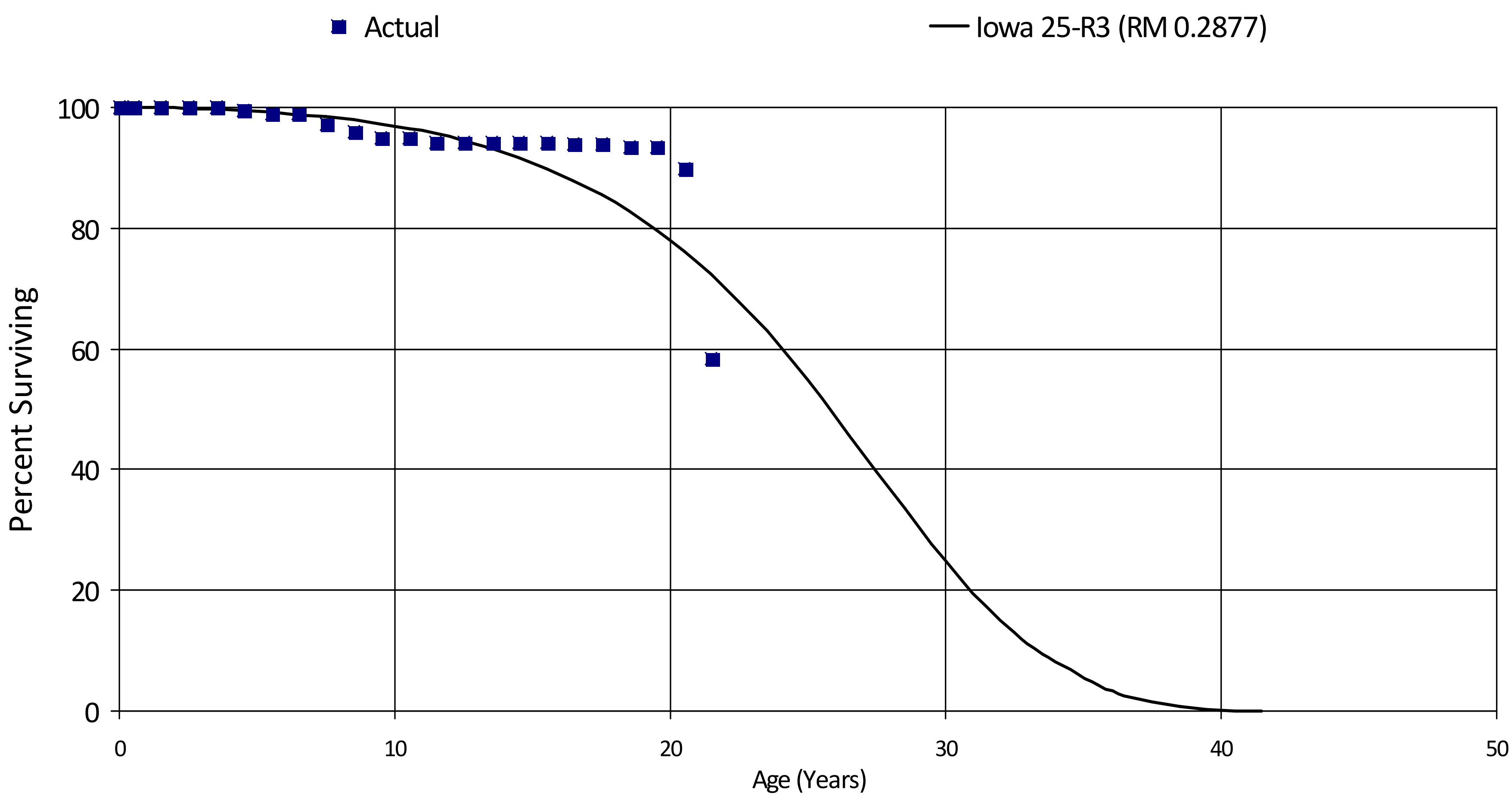
27.5	420,348	0	0.00000	1.00000	100.00
28.5	407,334	0	0.00000	1.00000	100.00
29.5	366,462	0	0.00000	1.00000	100.00
30.5	283,864	0	0.00000	1.00000	100.00
31.5	218,267	0	0.00000	1.00000	100.00
32.5	175,568	0	0.00000	1.00000	100.00
33.5	140,548	0	0.00000	1.00000	100.00
34.5	127,184	0	0.00000	1.00000	100.00
35.5	123,125	119,881	0.97366	0.02634	100.00
	Totals:	119,881			

BC Hydro Power Authority

Account 61001 - Fencing

Placement Band - 1986 - 2020 Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 61001 - Fencing

Placement Band - 1986 - 2020 Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

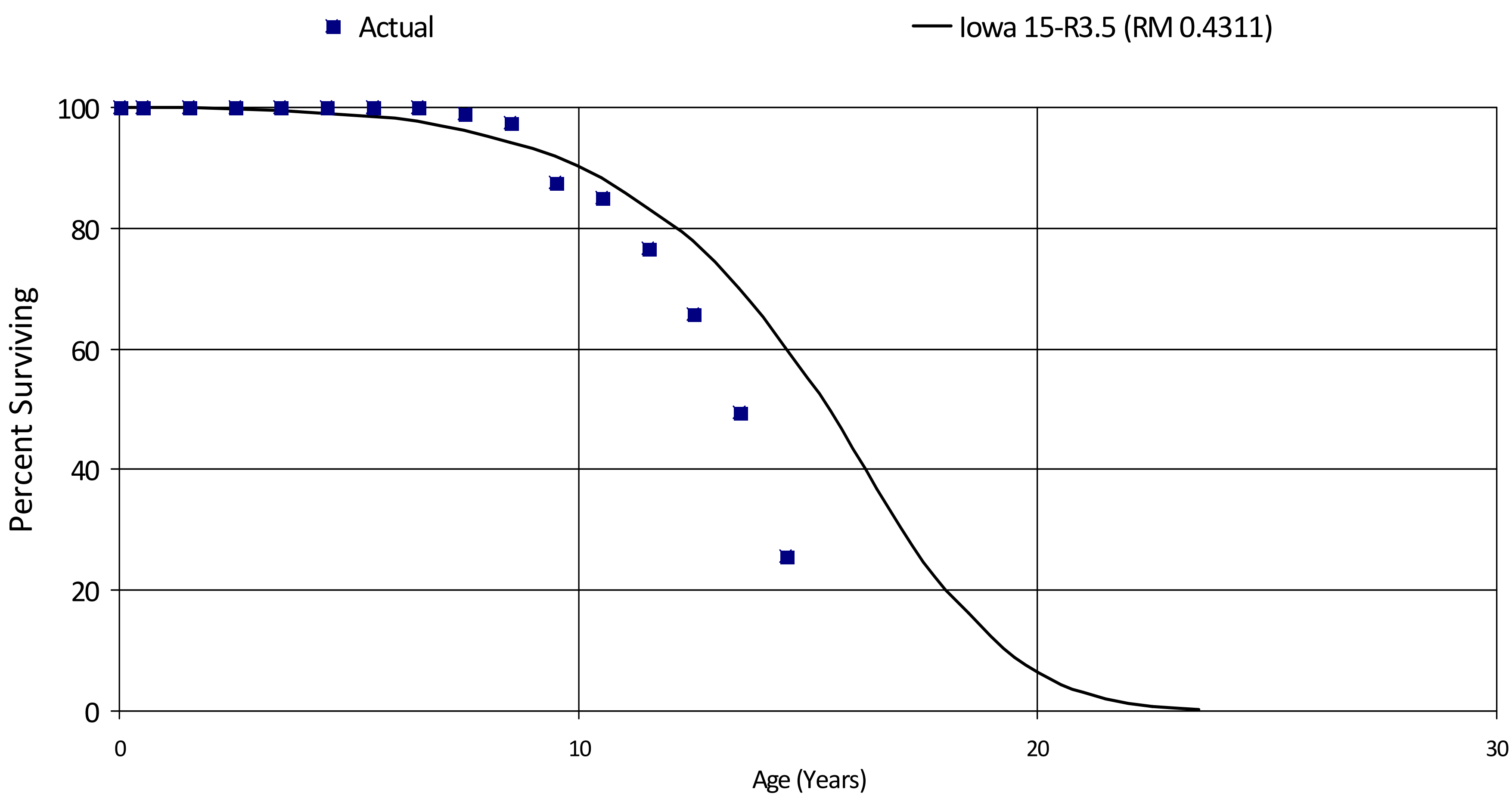
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	45,237,683	0	0.00000	1.00000	100.00
0.5	44,835,954	0	0.00000	1.00000	100.00
1.5	41,742,343	0	0.00000	1.00000	100.00
2.5	39,400,941	9,727	0.00025	0.99975	100.00
3.5	34,963,661	144,384	0.00413	0.99587	99.98
4.5	31,114,653	163,755	0.00526	0.99474	99.57
5.5	28,441,608	2	0.00000	1.00000	99.05
6.5	27,106,139	507,166	0.01871	0.98129	99.05
7.5	25,493,344	352,022	0.01381	0.98619	97.20
8.5	21,946,154	213,801	0.00974	0.99026	95.86
9.5	13,361,885	4,635	0.00035	0.99965	94.93
10.5	12,211,259	79,733	0.00653	0.99347	94.90
11.5	8,607,482	0	0.00000	1.00000	94.28
12.5	6,302,886	0	0.00000	1.00000	94.28
13.5	4,827,396	0	0.00000	1.00000	94.28
14.5	4,405,408	10,212	0.00232	0.99768	94.28
15.5	3,099,078	988	0.00032	0.99968	94.06
16.5	3,009,328	4,055	0.00135	0.99865	94.03
17.5	2,513,441	11,746	0.00467	0.99533	93.90
18.5	2,288,763	0	0.00000	1.00000	93.46
19.5	2,025,303	80,685	0.03984	0.96016	93.46
20.5	1,831,044	639,387	0.34919	0.65081	89.74
21.5	854,597	745,466	0.87230	0.12770	58.40
	Totals:	2,967,764			

BC Hydro Power Authority

Account 61101 - Alarm / Security System

Placement Band - 1993 - 2020 Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 61101 - Alarm / Security System

Placement Band - 1993 - 2020   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

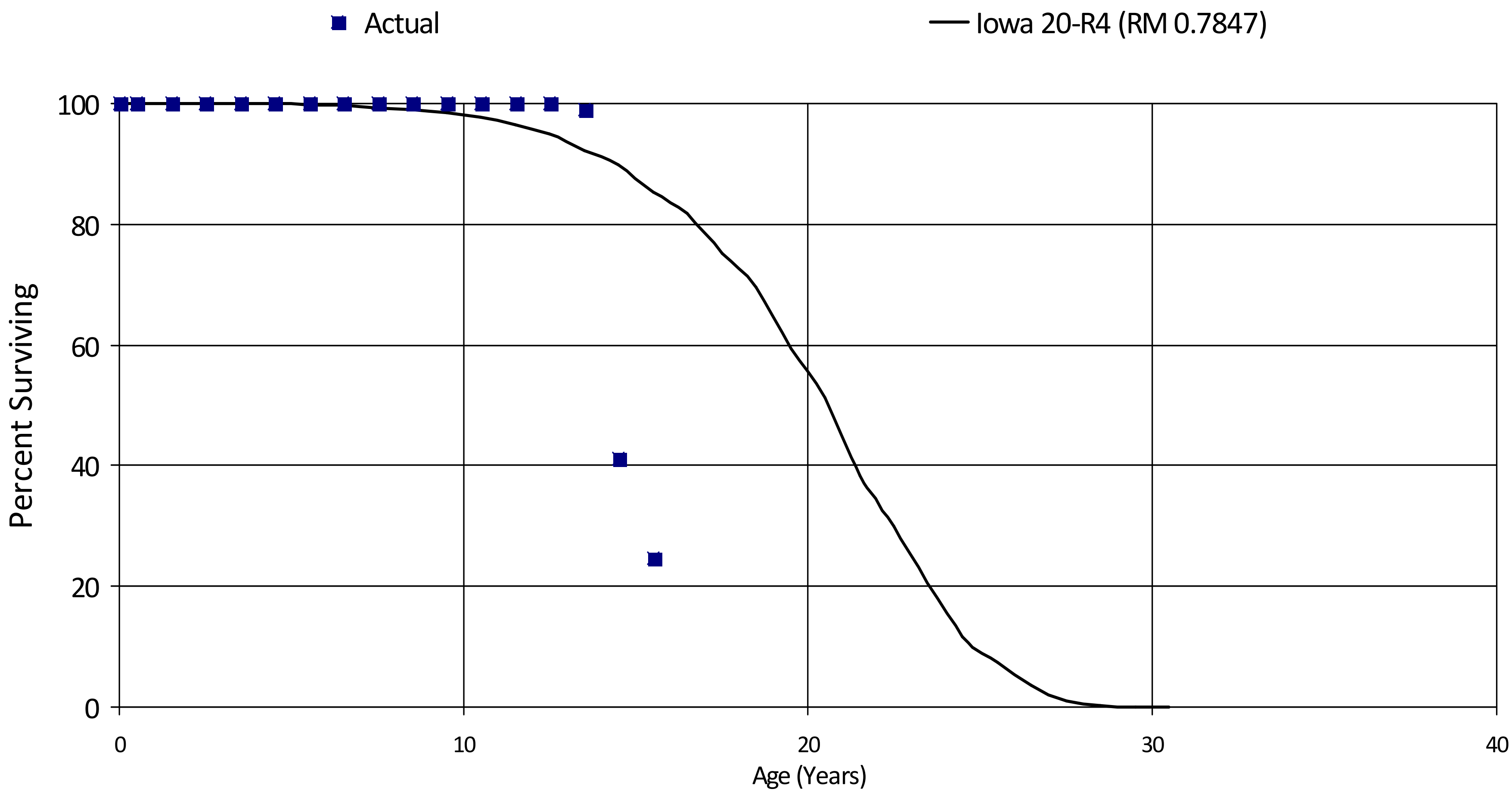
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	77,076,065	0	0.00000	1.00000	100.00
0.5	76,746,053	0	0.00000	1.00000	100.00
1.5	68,366,983	0	0.00000	1.00000	100.00
2.5	66,303,197	0	0.00000	1.00000	100.00
3.5	59,174,410	0	0.00000	1.00000	100.00
4.5	56,682,314	0	0.00000	1.00000	100.00
5.5	49,622,853	17	0.00000	1.00000	100.00
6.5	45,240,144	505,597	0.01118	0.98882	100.00
7.5	40,963,244	560,105	0.01367	0.98633	98.88
8.5	34,005,060	3,513,928	0.10334	0.89666	97.53
9.5	22,367,420	631,220	0.02822	0.97178	87.45
10.5	11,701,850	1,156,990	0.09887	0.90113	84.98
11.5	5,799,665	817,193	0.14090	0.85910	76.58
12.5	4,017,736	991,799	0.24686	0.75314	65.79
13.5	2,406,200	1,158,520	0.48147	0.51853	49.55
14.5	1,050,175	757,819	0.72161	0.27839	25.69
	Totals:	10,093,188			

BC Hydro Power Authority

Account 61201 - Booms, Floating

Placement Band - 1997 - 2018 Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 61201 - Booms, Floating

Placement Band - 1997 - 2018   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

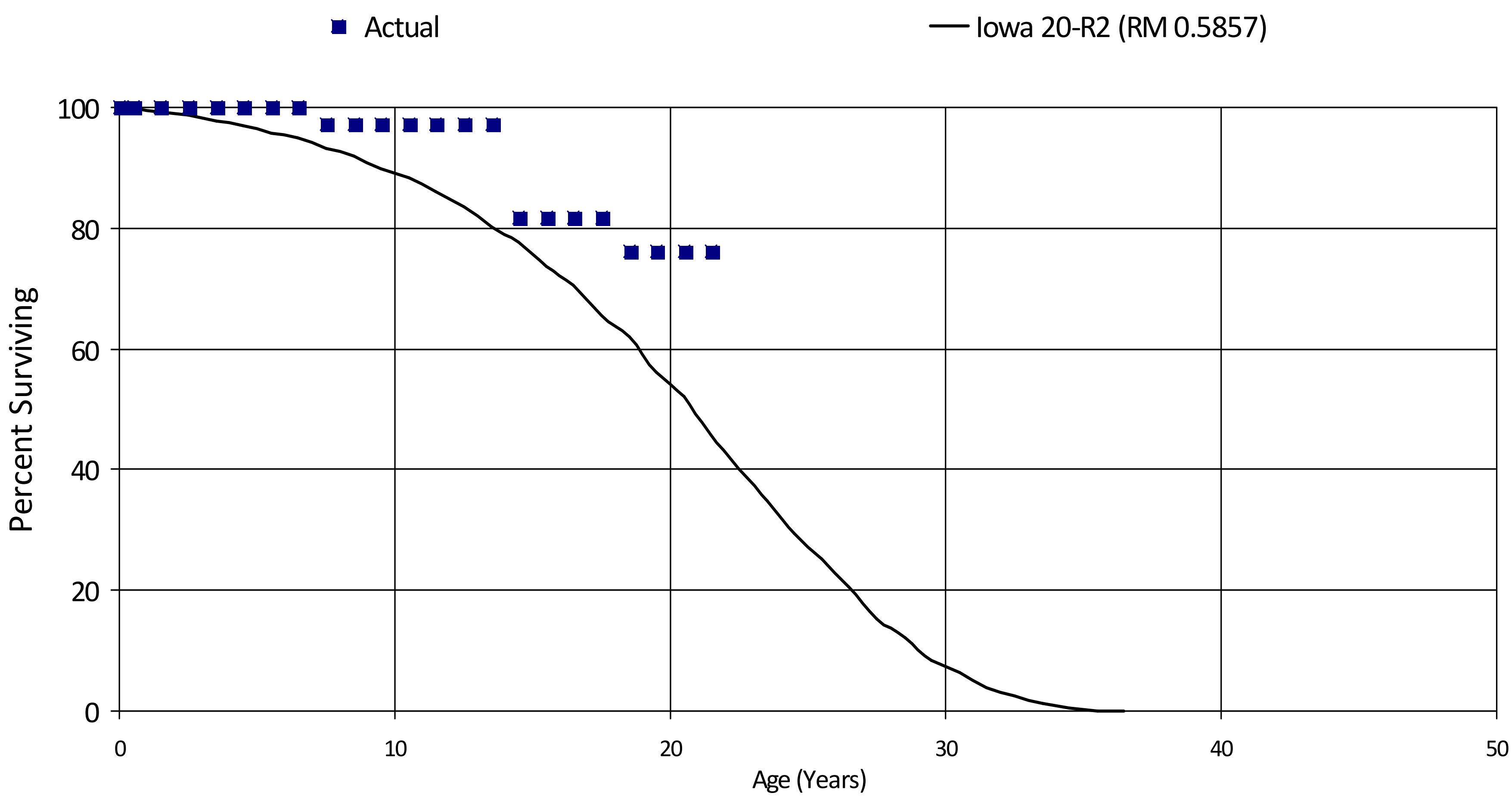
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	7,212,929	0	0.00000	1.00000	100.00
0.5	7,212,929	0	0.00000	1.00000	100.00
1.5	7,212,929	0	0.00000	1.00000	100.00
2.5	4,740,016	0	0.00000	1.00000	100.00
3.5	4,740,016	0	0.00000	1.00000	100.00
4.5	3,626,403	0	0.00000	1.00000	100.00
5.5	1,894,845	0	0.00000	1.00000	100.00
6.5	1,768,053	0	0.00000	1.00000	100.00
7.5	1,256,768	0	0.00000	1.00000	100.00
8.5	1,168,183	0	0.00000	1.00000	100.00
9.5	1,168,183	0	0.00000	1.00000	100.00
10.5	961,062	0	0.00000	1.00000	100.00
11.5	925,716	0	0.00000	1.00000	100.00
12.5	853,742	8,586	0.01006	0.98994	100.00
13.5	845,155	494,308	0.58487	0.41513	98.99
14.5	215,088	86,051	0.40007	0.59993	41.09
15.5	129,037	71,173	0.55157	0.44843	24.65
	Totals:	660,118			

BC Hydro Power Authority

Account 61202 - Booms, Floating Cedar

Placement Band - 1998 - 2020 Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 61202 - Booms, Floating Cedar

Placement Band - 1998 - 2020   Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

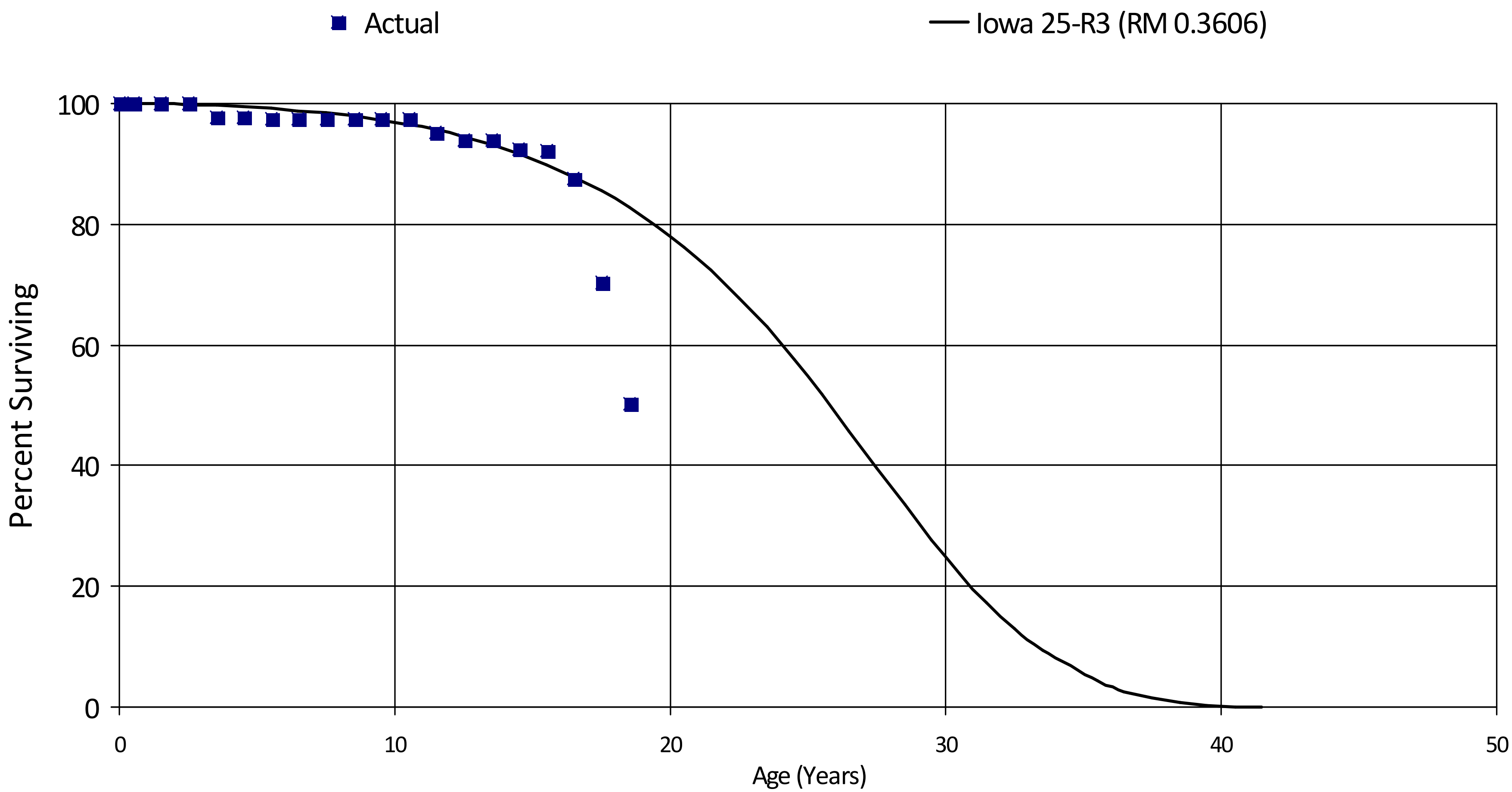
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	7,853,832	0	0.00000	1.00000	100.00
0.5	4,069,536	0	0.00000	1.00000	100.00
1.5	3,881,373	0	0.00000	1.00000	100.00
2.5	3,881,373	0	0.00000	1.00000	100.00
3.5	1,811,242	0	0.00000	1.00000	100.00
4.5	1,811,242	0	0.00000	1.00000	100.00
5.5	1,811,242	0	0.00000	1.00000	100.00
6.5	1,811,242	52,342	0.02890	0.97110	100.00
7.5	1,758,901	0	0.00000	1.00000	97.11
8.5	1,543,998	0	0.00000	1.00000	97.11
9.5	1,543,998	0	0.00000	1.00000	97.11
10.5	1,543,998	0	0.00000	1.00000	97.11
11.5	1,543,998	0	0.00000	1.00000	97.11
12.5	1,349,199	0	0.00000	1.00000	97.11
13.5	1,329,336	210,397	0.15827	0.84173	97.11
14.5	881,681	0	0.00000	1.00000	81.74
15.5	881,681	0	0.00000	1.00000	81.74
16.5	735,772	0	0.00000	1.00000	81.74
17.5	735,772	49,846	0.06775	0.93225	81.74
18.5	403,436	0	0.00000	1.00000	76.20
19.5	403,436	0	0.00000	1.00000	76.20
20.5	391,377	0	0.00000	1.00000	76.20
21.5	230,254	0	0.00000	1.00000	76.20
	Totals:	312,585			

BC Hydro Power Authority

Account 62001 - Fire Protection System

Placement Band - 1986 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 62001 - Fire Protection System

Placement Band - 1986 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

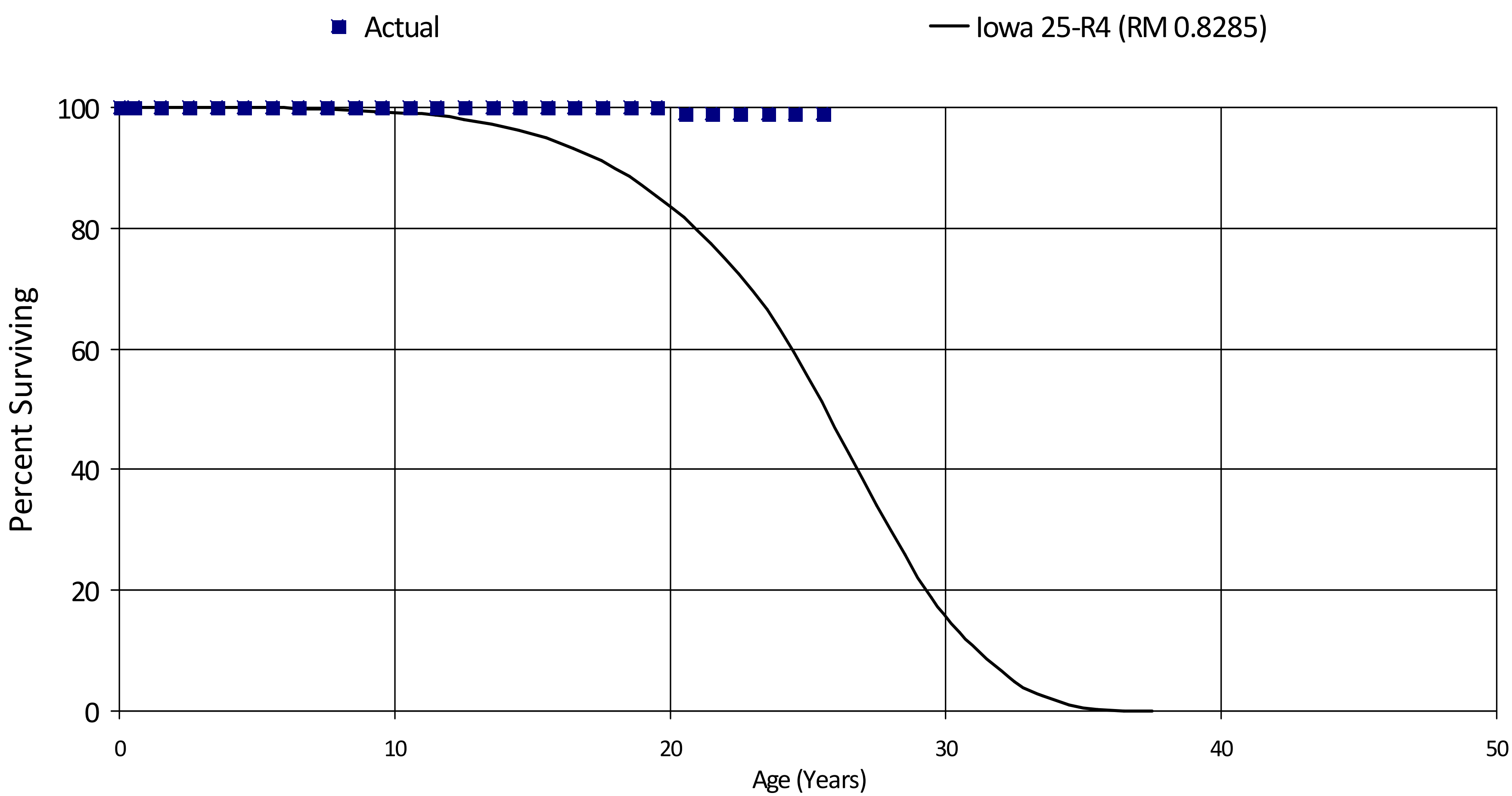
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	113,854,508	0	0.00000	1.00000	100.00
0.5	97,897,404	0	0.00000	1.00000	100.00
1.5	91,431,999	0	0.00000	1.00000	100.00
2.5	81,914,278	1,854,000	0.02263	0.97737	100.00
3.5	75,404,615	0	0.00000	1.00000	97.74
4.5	70,388,034	198,009	0.00281	0.99719	97.74
5.5	65,282,955	0	0.00000	1.00000	97.47
6.5	56,034,894	0	0.00000	1.00000	97.47
7.5	53,946,955	0	0.00000	1.00000	97.47
8.5	45,137,553	0	0.00000	1.00000	97.47
9.5	45,137,553	0	0.00000	1.00000	97.47
10.5	32,763,419	800,153	0.02442	0.97558	97.47
11.5	27,995,658	373,866	0.01335	0.98665	95.09
12.5	27,160,903	0	0.00000	1.00000	93.82
13.5	26,218,718	401,069	0.01530	0.98470	93.82
14.5	12,346,235	28,476	0.00231	0.99769	92.38
15.5	10,081,558	507,185	0.05031	0.94969	92.17
16.5	5,328,127	1,044,994	0.19613	0.80387	87.53
17.5	3,761,521	1,068,260	0.28400	0.71600	70.36
18.5	1,892,212	261,955	0.13844	0.86156	50.38
	Totals:	6,537,967			

BC Hydro Power Authority

Account 62501 - Firefighting Equipment

Placement Band - 1989 - 2019 Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 62501 - Firefighting Equipment

Placement Band - 1989 - 2019 Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

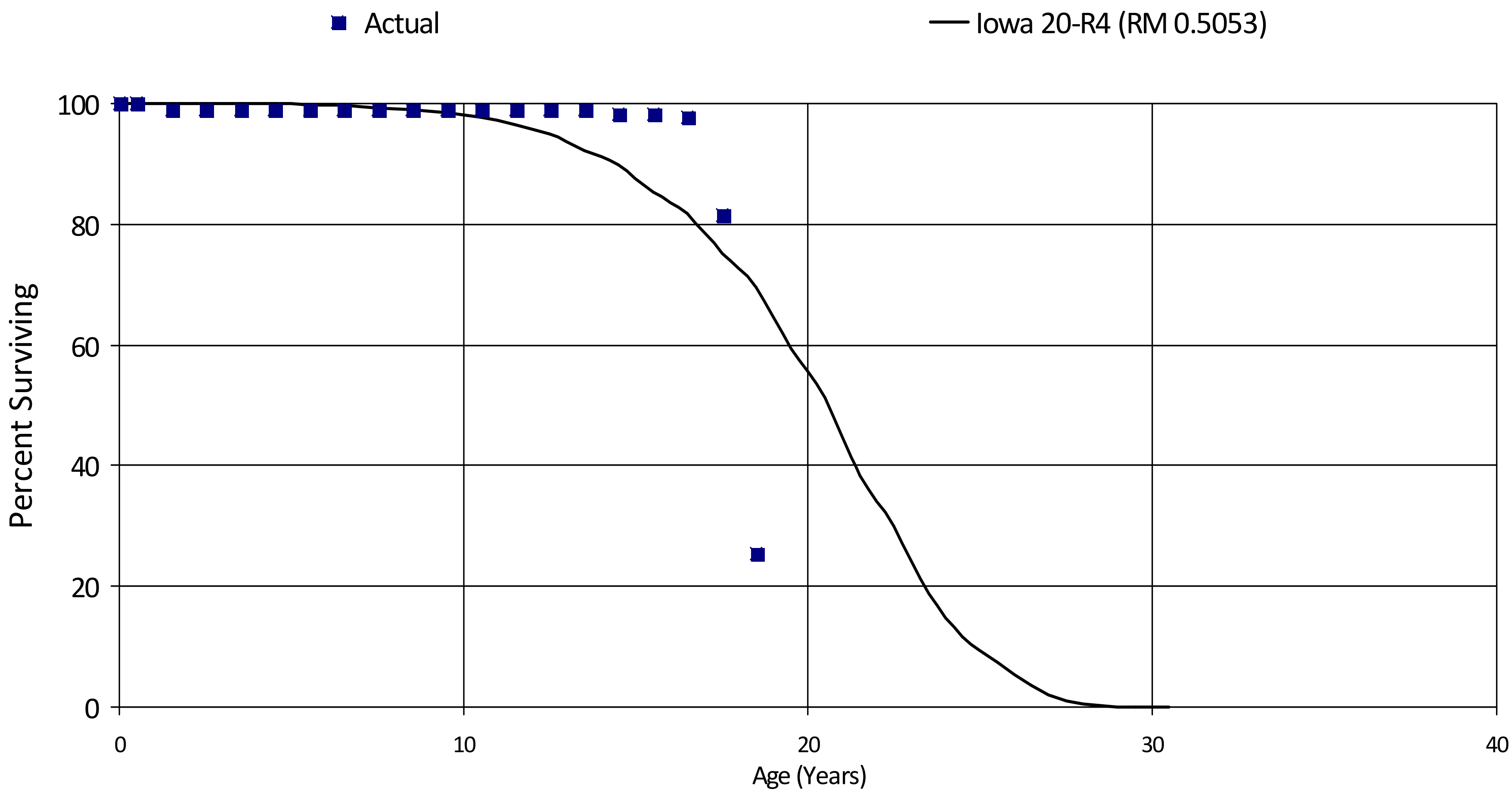
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	3,784,869	0	0.00000	1.00000	100.00
0.5	3,784,869	0	0.00000	1.00000	100.00
1.5	3,704,746	0	0.00000	1.00000	100.00
2.5	348,205	0	0.00000	1.00000	100.00
3.5	266,584	0	0.00000	1.00000	100.00
4.5	256,404	0	0.00000	1.00000	100.00
5.5	243,159	0	0.00000	1.00000	100.00
6.5	243,159	0	0.00000	1.00000	100.00
7.5	243,159	0	0.00000	1.00000	100.00
8.5	218,209	0	0.00000	1.00000	100.00
9.5	218,209	0	0.00000	1.00000	100.00
10.5	218,209	0	0.00000	1.00000	100.00
11.5	115,604	0	0.00000	1.00000	100.00
12.5	115,604	0	0.00000	1.00000	100.00
13.5	114,596	0	0.00000	1.00000	100.00
14.5	114,596	0	0.00000	1.00000	100.00
15.5	114,596	0	0.00000	1.00000	100.00
16.5	114,596	0	0.00000	1.00000	100.00
17.5	81,085	0	0.00000	1.00000	100.00
18.5	81,085	0	0.00000	1.00000	100.00
19.5	69,169	785	0.01135	0.98865	100.00
20.5	68,383	0	0.00000	1.00000	98.86
21.5	62,695	0	0.00000	1.00000	98.86
22.5	62,695	0	0.00000	1.00000	98.86
23.5	62,695	0	0.00000	1.00000	98.86
24.5	60,067	0	0.00000	1.00000	98.86
25.5	59,955	46,313	0.77247	0.22753	98.86
	Totals:	47,098			

BC Hydro Power Authority

Account 65001 - Protection and Control Equipment and Relay

Placement Band - 1987 - 2020 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 65001 - Protection and Control Equipment and Relay

Placement Band - 1987 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

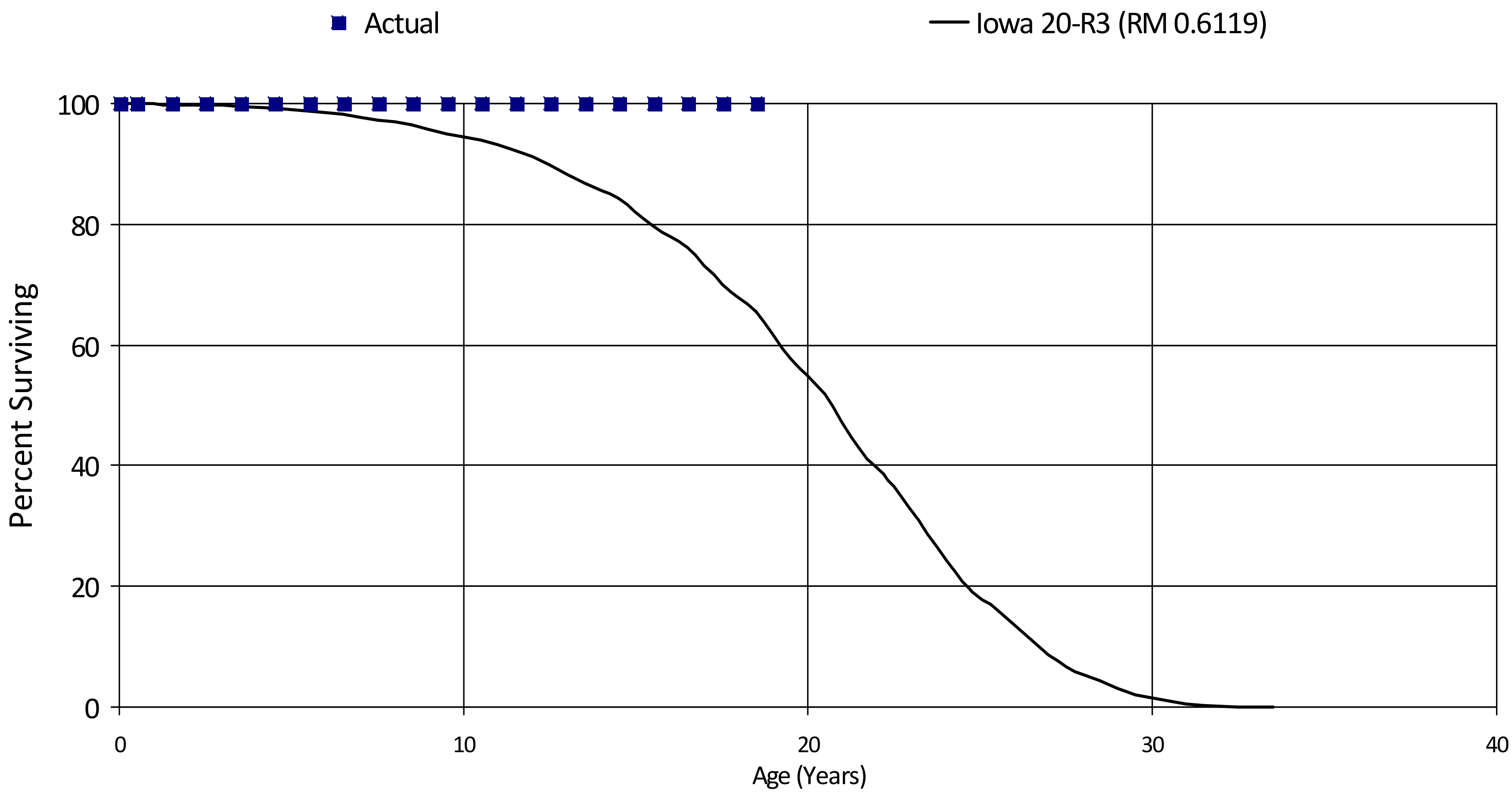
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	516,244,024	0	0.00000	1.00000	100.00
0.5	512,294,752	4,617,038	0.00901	0.99099	100.00
1.5	445,683,606	0	0.00000	1.00000	99.10
2.5	422,116,176	0	0.00000	1.00000	99.10
3.5	380,023,211	0	0.00000	1.00000	99.10
4.5	330,123,185	0	0.00000	1.00000	99.10
5.5	273,561,694	0	0.00000	1.00000	99.10
6.5	238,586,619	0	0.00000	1.00000	99.10
7.5	213,679,760	0	0.00000	1.00000	99.10
8.5	182,476,664	0	0.00000	1.00000	99.10
9.5	153,499,651	931	0.00001	0.99999	99.10
10.5	130,061,835	3,133	0.00002	0.99998	99.10
11.5	101,648,237	0	0.00000	1.00000	99.10
12.5	87,987,516	152,063	0.00173	0.99827	99.10
13.5	73,768,905	480,944	0.00652	0.99348	98.93
14.5	59,233,443	287	0.00000	1.00000	98.28
15.5	48,376,249	314,807	0.00651	0.99349	98.28
16.5	37,619,842	6,182,646	0.16435	0.83565	97.64
17.5	23,334,088	16,043,332	0.68755	0.31245	81.59
18.5	7,290,755	7,226,682	0.99121	0.00879	25.49
	Totals:	35,021,863			

BC Hydro Power Authority

Account 65101 - Fault Locating & Reporting

Placement Band - 1997 - 2019   Experience Band - 2018 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 65101 - Fault Locating & Reporting

Placement Band - 1997 - 2019 Experience Band - 2018 - 2020

RETIREMENT RATE ANALYSIS

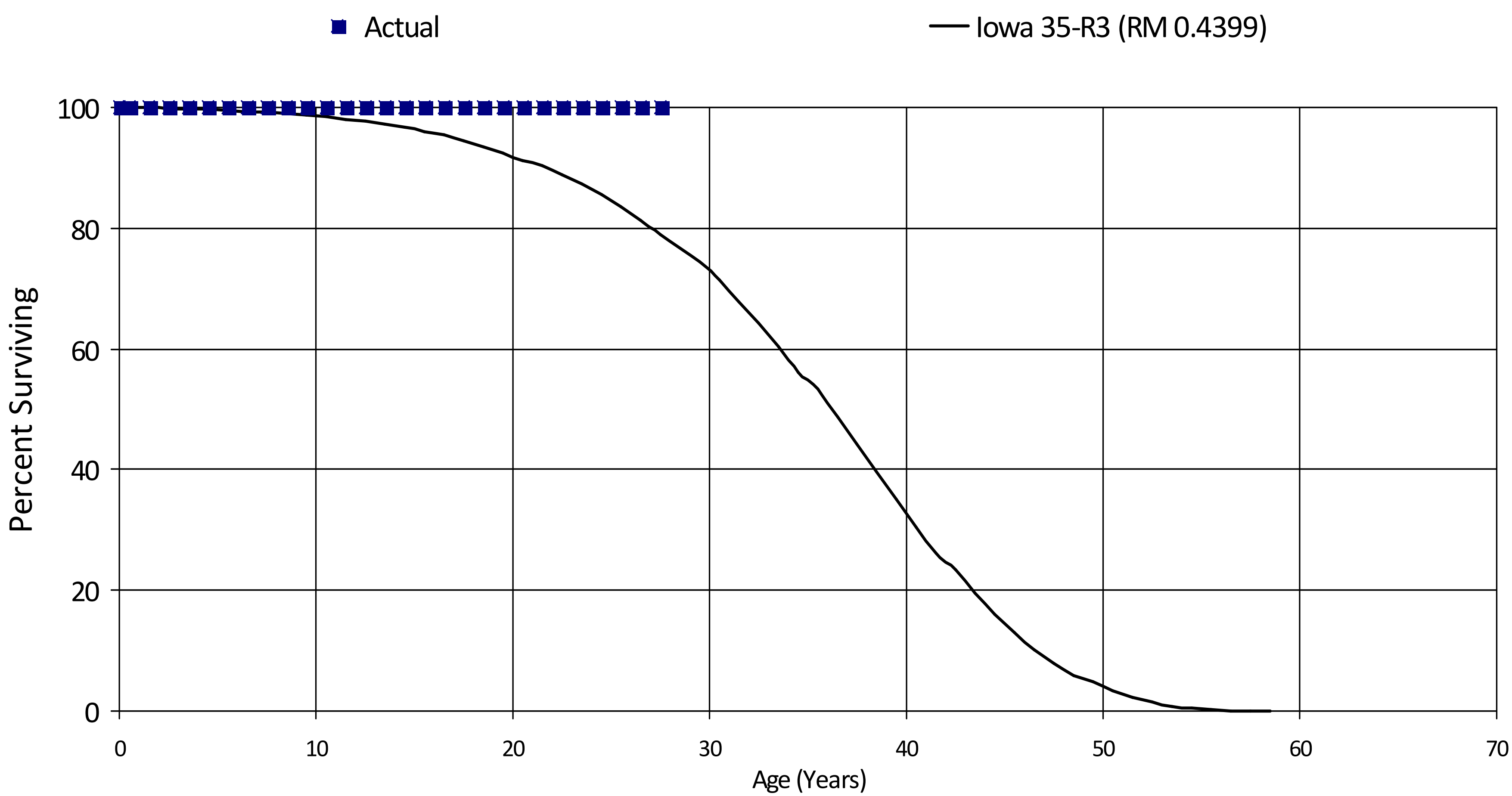
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	5,928,638	0	0.00000	1.00000	100.00
0.5	5,928,638	0	0.00000	1.00000	100.00
1.5	4,354,318	0	0.00000	1.00000	100.00
2.5	4,331,760	0	0.00000	1.00000	100.00
3.5	4,226,676	0	0.00000	1.00000	100.00
4.5	2,945,689	0	0.00000	1.00000	100.00
5.5	2,636,804	0	0.00000	1.00000	100.00
6.5	2,529,984	0	0.00000	1.00000	100.00
7.5	2,529,984	0	0.00000	1.00000	100.00
8.5	2,411,648	0	0.00000	1.00000	100.00
9.5	2,361,315	0	0.00000	1.00000	100.00
10.5	773,713	0	0.00000	1.00000	100.00
11.5	773,713	0	0.00000	1.00000	100.00
12.5	424,388	0	0.00000	1.00000	100.00
13.5	382,267	0	0.00000	1.00000	100.00
14.5	292,590	0	0.00000	1.00000	100.00
15.5	118,627	0	0.00000	1.00000	100.00
16.5	118,627	0	0.00000	1.00000	100.00
17.5	108,647	0	0.00000	1.00000	100.00
18.5	65,372	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 67001 - Liner, Pvc, Spill Containment

Placement Band - 1992 - 2003 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 67001 - Liner, Pvc, Spill Containment

Placement Band - 1992 - 2003   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	379,695	0	0.00000	1.00000	100.00
0.5	379,695	0	0.00000	1.00000	100.00
1.5	379,695	0	0.00000	1.00000	100.00
2.5	379,695	0	0.00000	1.00000	100.00
3.5	379,695	0	0.00000	1.00000	100.00
4.5	379,695	0	0.00000	1.00000	100.00
5.5	379,695	0	0.00000	1.00000	100.00
6.5	379,695	0	0.00000	1.00000	100.00
7.5	379,695	0	0.00000	1.00000	100.00
8.5	379,695	0	0.00000	1.00000	100.00
9.5	379,695	0	0.00000	1.00000	100.00
10.5	379,695	0	0.00000	1.00000	100.00
11.5	379,695	0	0.00000	1.00000	100.00
12.5	379,695	0	0.00000	1.00000	100.00
13.5	379,695	0	0.00000	1.00000	100.00
14.5	379,695	0	0.00000	1.00000	100.00
15.5	379,695	0	0.00000	1.00000	100.00
16.5	379,695	0	0.00000	1.00000	100.00
17.5	379,694	0	0.00000	1.00000	100.00
18.5	335,771	0	0.00000	1.00000	100.00
19.5	335,770	0	0.00000	1.00000	100.00
20.5	332,694	0	0.00000	1.00000	100.00
21.5	309,506	0	0.00000	1.00000	100.00
22.5	245,288	0	0.00000	1.00000	100.00
23.5	185,278	0	0.00000	1.00000	100.00
24.5	151,159	0	0.00000	1.00000	100.00
25.5	37,884	0	0.00000	1.00000	100.00
26.5	33,492	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 67001 - Liner, Pvc, Spill Containment

Placement Band - 1992 - 2003 Experience Band - 2020 - 2020

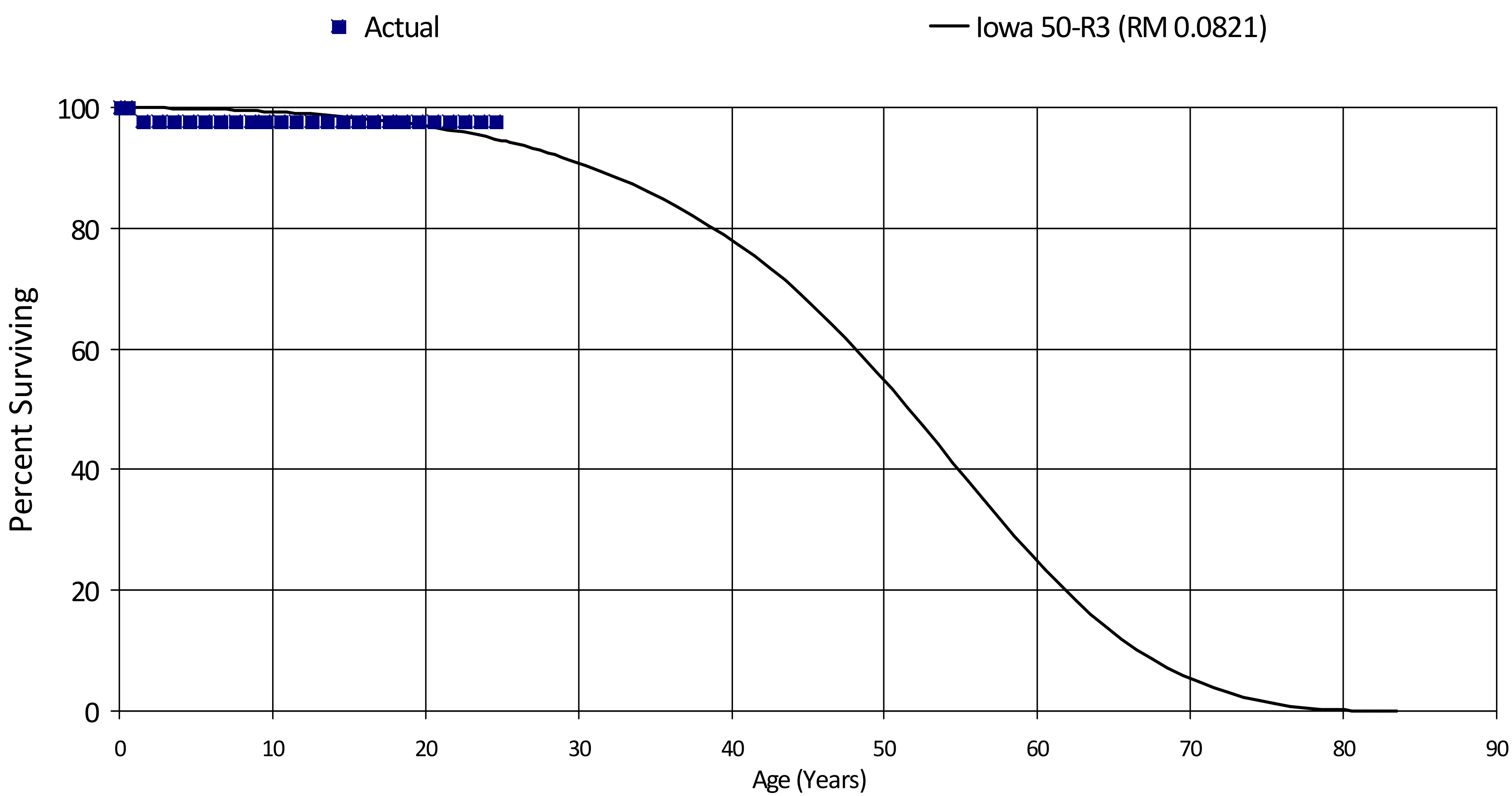
27.5	6,840	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 67003 - Containment Facility, Concrete

Placement Band - 1994 - 2017   Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 67003 - Containment Facility, Concrete

Placement Band - 1994 - 2017   Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

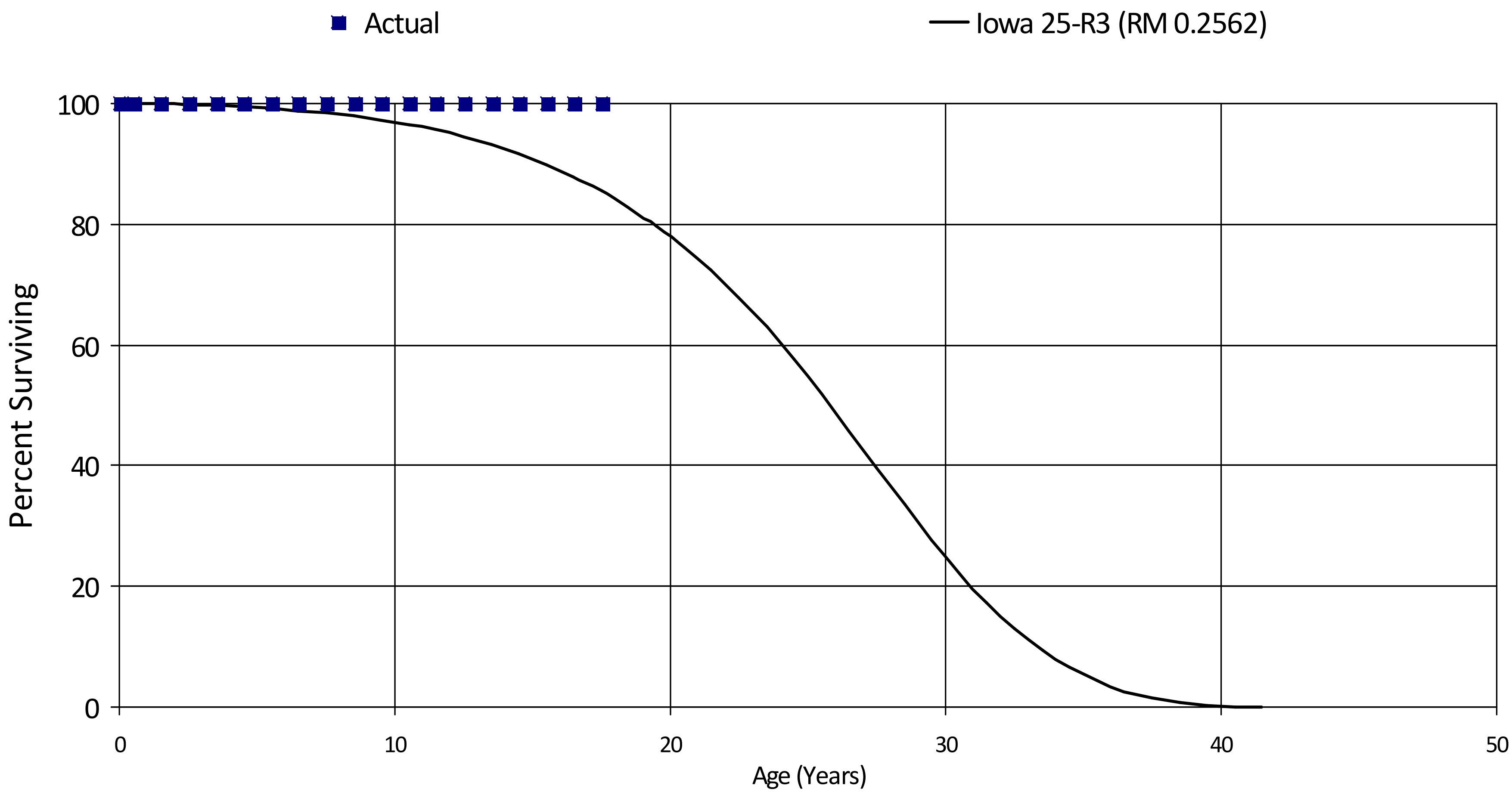
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	27,679,379	0	0.00000	1.00000	100.00
0.5	27,679,379	651,317	0.02353	0.97647	100.00
1.5	27,028,062	0	0.00000	1.00000	97.65
2.5	27,028,062	0	0.00000	1.00000	97.65
3.5	24,681,606	0	0.00000	1.00000	97.65
4.5	21,127,917	0	0.00000	1.00000	97.65
5.5	20,442,889	0	0.00000	1.00000	97.65
6.5	19,277,806	0	0.00000	1.00000	97.65
7.5	18,408,462	0	0.00000	1.00000	97.65
8.5	12,915,202	0	0.00000	1.00000	97.65
9.5	12,531,399	0	0.00000	1.00000	97.65
10.5	10,465,039	0	0.00000	1.00000	97.65
11.5	7,825,105	0	0.00000	1.00000	97.65
12.5	4,966,292	0	0.00000	1.00000	97.65
13.5	4,513,978	0	0.00000	1.00000	97.65
14.5	3,677,878	0	0.00000	1.00000	97.65
15.5	3,335,219	0	0.00000	1.00000	97.65
16.5	3,133,565	0	0.00000	1.00000	97.65
17.5	3,133,565	0	0.00000	1.00000	97.65
18.5	3,110,873	0	0.00000	1.00000	97.65
19.5	2,852,801	0	0.00000	1.00000	97.65
20.5	2,598,113	0	0.00000	1.00000	97.65
21.5	1,869,074	0	0.00000	1.00000	97.65
22.5	1,541,703	0	0.00000	1.00000	97.65
23.5	1,293,607	0	0.00000	1.00000	97.65
24.5	1,191,882	0	0.00000	1.00000	97.65
	Totals:	651,317			

BC Hydro Power Authority

Account 67004 - Spill Pond, Natural

Placement Band - 2002 - 2003   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 67004 - Spill Pond, Natural

Placement Band - 2002 - 2003 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

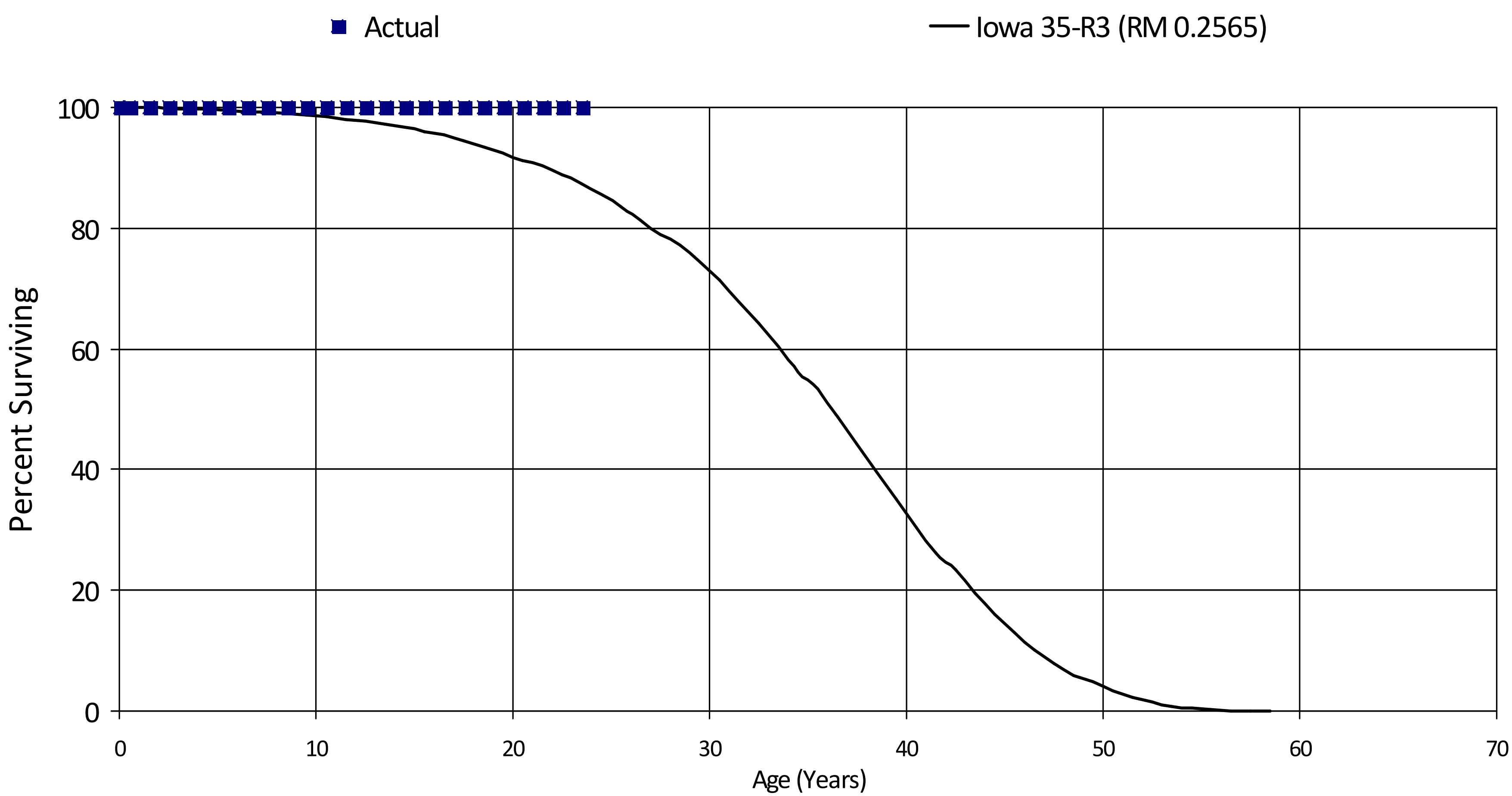
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	67,216	0	0.00000	1.00000	100.00
0.5	67,216	0	0.00000	1.00000	100.00
1.5	67,216	0	0.00000	1.00000	100.00
2.5	67,216	0	0.00000	1.00000	100.00
3.5	67,216	0	0.00000	1.00000	100.00
4.5	67,216	0	0.00000	1.00000	100.00
5.5	67,216	0	0.00000	1.00000	100.00
6.5	67,216	0	0.00000	1.00000	100.00
7.5	67,216	0	0.00000	1.00000	100.00
8.5	67,216	0	0.00000	1.00000	100.00
9.5	67,216	0	0.00000	1.00000	100.00
10.5	67,216	0	0.00000	1.00000	100.00
11.5	67,216	0	0.00000	1.00000	100.00
12.5	67,216	0	0.00000	1.00000	100.00
13.5	67,216	0	0.00000	1.00000	100.00
14.5	67,216	0	0.00000	1.00000	100.00
15.5	67,216	0	0.00000	1.00000	100.00
16.5	67,216	0	0.00000	1.00000	100.00
17.5	66,106	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 67005 - Oil Spill Containment

Placement Band - 1996 - 2018 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 67005 - Oil Spill Containment

Placement Band - 1996 - 2018   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

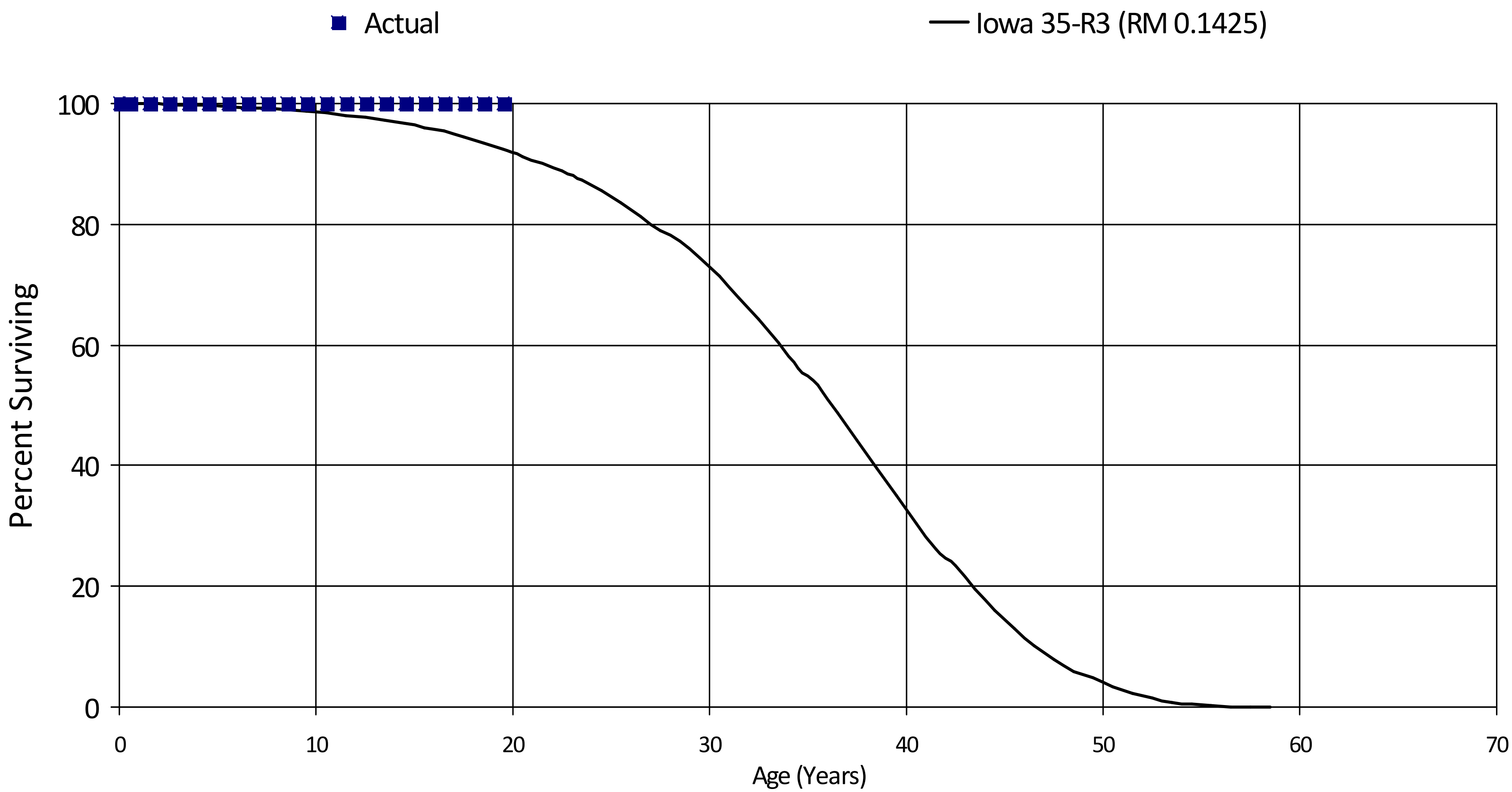
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	8,202,904	0	0.00000	1.00000	100.00
0.5	8,202,904	0	0.00000	1.00000	100.00
1.5	8,202,904	0	0.00000	1.00000	100.00
2.5	7,661,589	0	0.00000	1.00000	100.00
3.5	7,278,431	0	0.00000	1.00000	100.00
4.5	6,751,957	0	0.00000	1.00000	100.00
5.5	6,204,490	0	0.00000	1.00000	100.00
6.5	6,051,344	0	0.00000	1.00000	100.00
7.5	6,051,344	0	0.00000	1.00000	100.00
8.5	5,597,640	0	0.00000	1.00000	100.00
9.5	5,577,153	0	0.00000	1.00000	100.00
10.5	5,271,457	0	0.00000	1.00000	100.00
11.5	5,268,642	0	0.00000	1.00000	100.00
12.5	4,924,677	0	0.00000	1.00000	100.00
13.5	4,271,009	0	0.00000	1.00000	100.00
14.5	3,815,749	0	0.00000	1.00000	100.00
15.5	3,815,749	0	0.00000	1.00000	100.00
16.5	3,812,594	0	0.00000	1.00000	100.00
17.5	3,602,734	0	0.00000	1.00000	100.00
18.5	3,121,678	0	0.00000	1.00000	100.00
19.5	3,067,867	0	0.00000	1.00000	100.00
20.5	2,971,281	0	0.00000	1.00000	100.00
21.5	2,733,463	0	0.00000	1.00000	100.00
22.5	1,807,798	0	0.00000	1.00000	100.00
23.5	1,807,798	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 67006 - Containment System, Oil Spill

Placement Band - 1999 - 2019   Experience Band - 2015 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 67006 - Containment System, Oil Spill

Placement Band - 1999 - 2019   Experience Band - 2015 - 2020

RETIREMENT RATE ANALYSIS

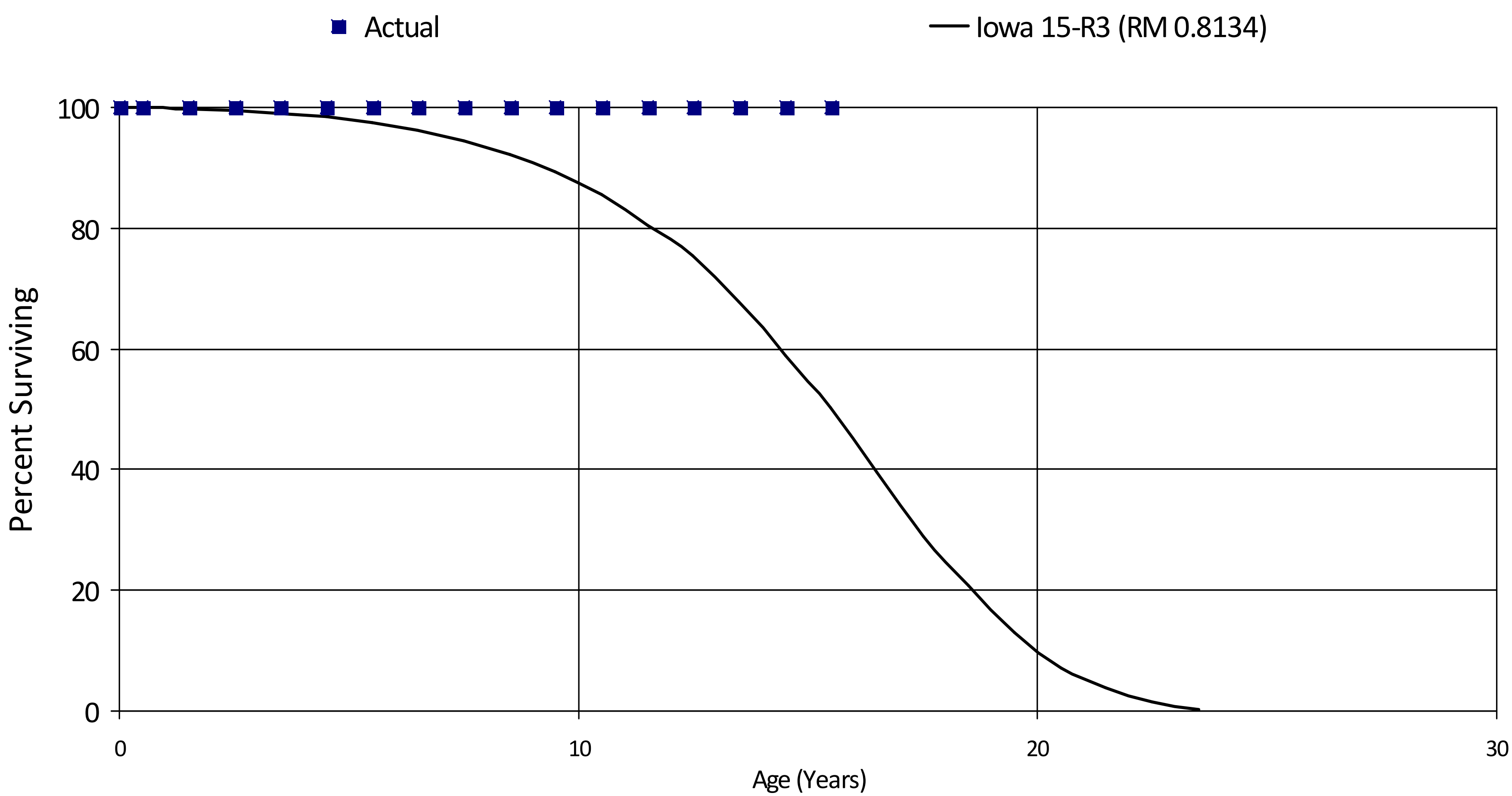
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	14,914,880	0	0.00000	1.00000	100.00
0.5	14,914,880	0	0.00000	1.00000	100.00
1.5	13,229,245	0	0.00000	1.00000	100.00
2.5	12,113,943	0	0.00000	1.00000	100.00
3.5	12,062,801	0	0.00000	1.00000	100.00
4.5	12,062,801	0	0.00000	1.00000	100.00
5.5	12,062,801	0	0.00000	1.00000	100.00
6.5	10,229,590	0	0.00000	1.00000	100.00
7.5	10,223,443	0	0.00000	1.00000	100.00
8.5	10,223,443	0	0.00000	1.00000	100.00
9.5	10,223,443	0	0.00000	1.00000	100.00
10.5	9,611,505	0	0.00000	1.00000	100.00
11.5	9,001,025	0	0.00000	1.00000	100.00
12.5	8,258,497	0	0.00000	1.00000	100.00
13.5	5,787,844	0	0.00000	1.00000	100.00
14.5	3,055,022	0	0.00000	1.00000	100.00
15.5	2,785,297	0	0.00000	1.00000	100.00
16.5	2,232,073	0	0.00000	1.00000	100.00
17.5	872,485	0	0.00000	1.00000	100.00
18.5	872,485	0	0.00000	1.00000	100.00
19.5	360,190	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 68001 - Carrier System, Power Line

Placement Band - 1996 - 2017   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68001 - Carrier System, Power Line

Placement Band - 1996 - 2017   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

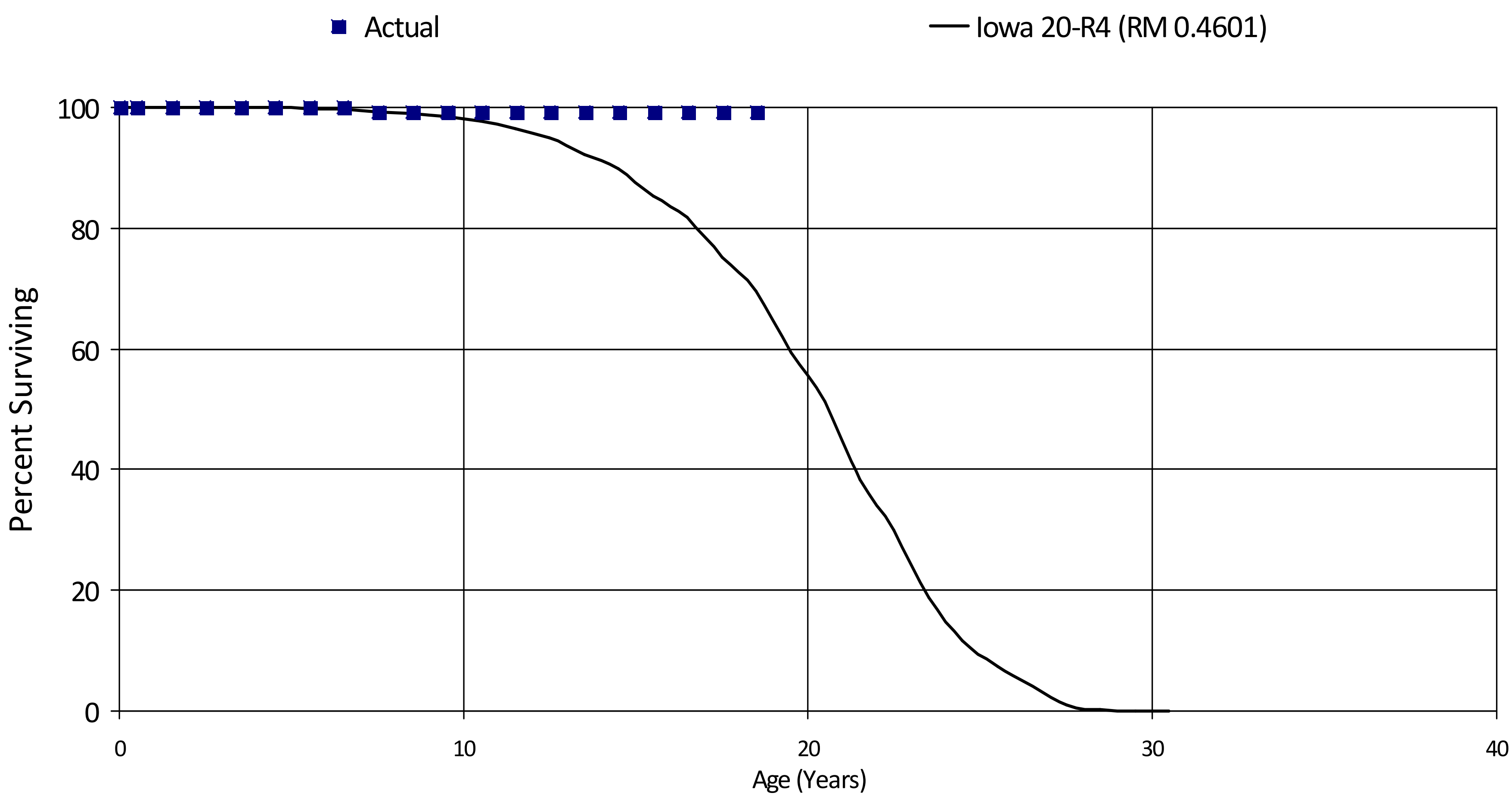
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	7,290,947	0	0.00000	1.00000	100.00
0.5	7,290,947	0	0.00000	1.00000	100.00
1.5	7,290,947	0	0.00000	1.00000	100.00
2.5	7,290,947	0	0.00000	1.00000	100.00
3.5	6,878,962	0	0.00000	1.00000	100.00
4.5	6,878,962	0	0.00000	1.00000	100.00
5.5	6,827,088	0	0.00000	1.00000	100.00
6.5	6,797,861	0	0.00000	1.00000	100.00
7.5	6,492,393	0	0.00000	1.00000	100.00
8.5	5,357,772	0	0.00000	1.00000	100.00
9.5	4,751,329	0	0.00000	1.00000	100.00
10.5	4,507,008	0	0.00000	1.00000	100.00
11.5	2,977,600	0	0.00000	1.00000	100.00
12.5	2,667,843	0	0.00000	1.00000	100.00
13.5	1,647,494	0	0.00000	1.00000	100.00
14.5	382,922	0	0.00000	1.00000	100.00
15.5	308,796	268,585	0.86978	0.13022	100.00
	Totals:	268,585			

BC Hydro Power Authority

Account 68101 - Antennae & Waveguide, Microwave

Placement Band - 1994 - 2020   Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68101 - Antennae & Waveguide, Microwave

Placement Band - 1994 - 2020   Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

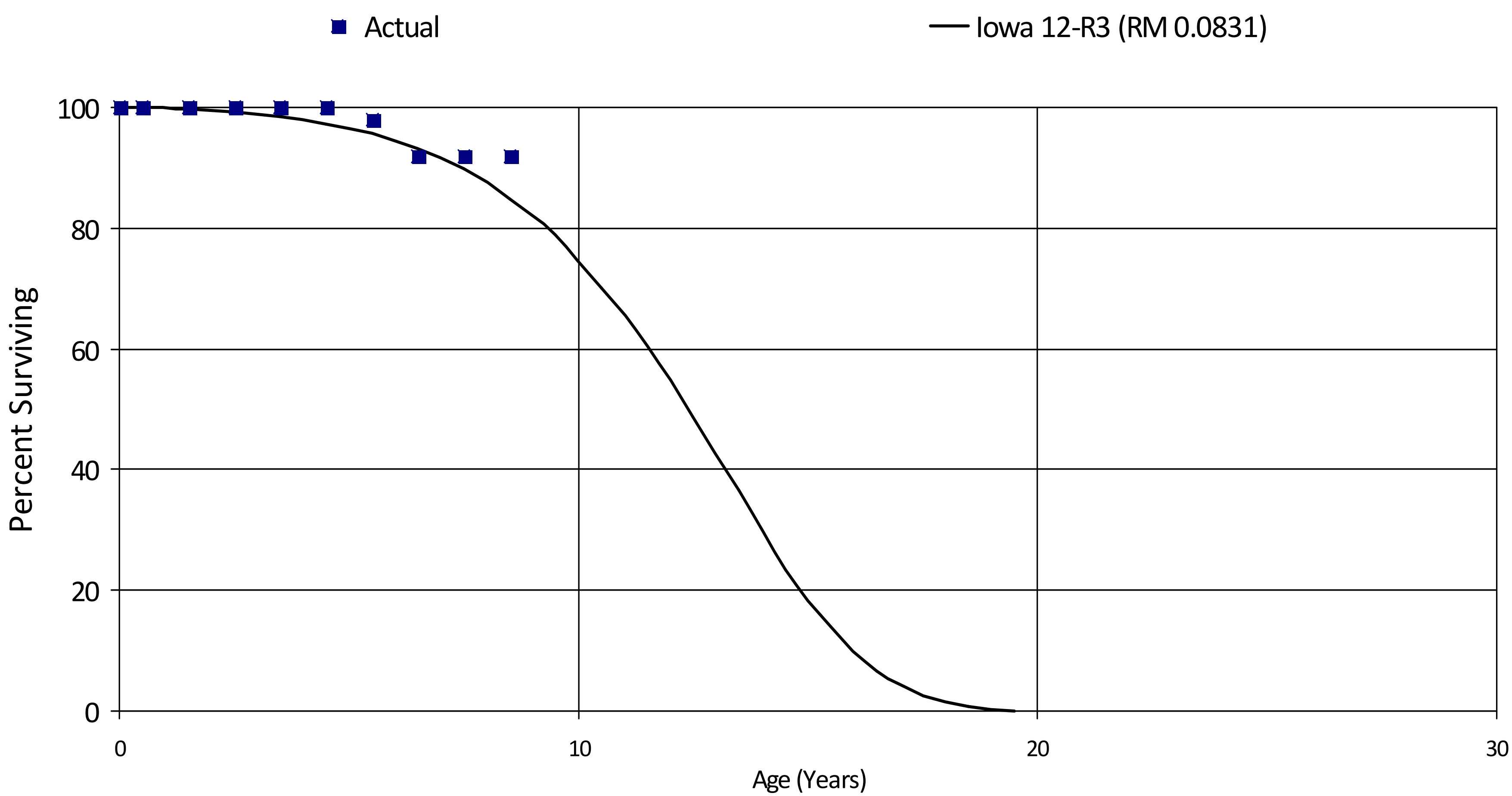
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	29,744,029	0	0.00000	1.00000	100.00
0.5	28,661,610	0	0.00000	1.00000	100.00
1.5	28,160,161	0	0.00000	1.00000	100.00
2.5	26,100,821	0	0.00000	1.00000	100.00
3.5	18,732,502	0	0.00000	1.00000	100.00
4.5	12,235,959	0	0.00000	1.00000	100.00
5.5	8,926,150	0	0.00000	1.00000	100.00
6.5	6,780,892	56,588	0.00835	0.99165	100.00
7.5	6,398,107	0	0.00000	1.00000	99.16
8.5	6,398,107	0	0.00000	1.00000	99.16
9.5	4,116,749	0	0.00000	1.00000	99.16
10.5	3,370,999	0	0.00000	1.00000	99.16
11.5	3,104,962	0	0.00000	1.00000	99.16
12.5	3,016,563	0	0.00000	1.00000	99.16
13.5	2,051,029	0	0.00000	1.00000	99.16
14.5	1,984,494	0	0.00000	1.00000	99.16
15.5	1,939,563	0	0.00000	1.00000	99.16
16.5	1,534,744	0	0.00000	1.00000	99.16
17.5	1,495,521	0	0.00000	1.00000	99.16
18.5	1,431,837	63,755	0.04453	0.95547	99.16
	Totals:	120,343			

BC Hydro Power Authority

Account 68201 - Control Centre (Master Equip)

Placement Band - 1927 - 2020   Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68201 - Control Centre (Master Equip)

Placement Band - 1927 - 2020   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

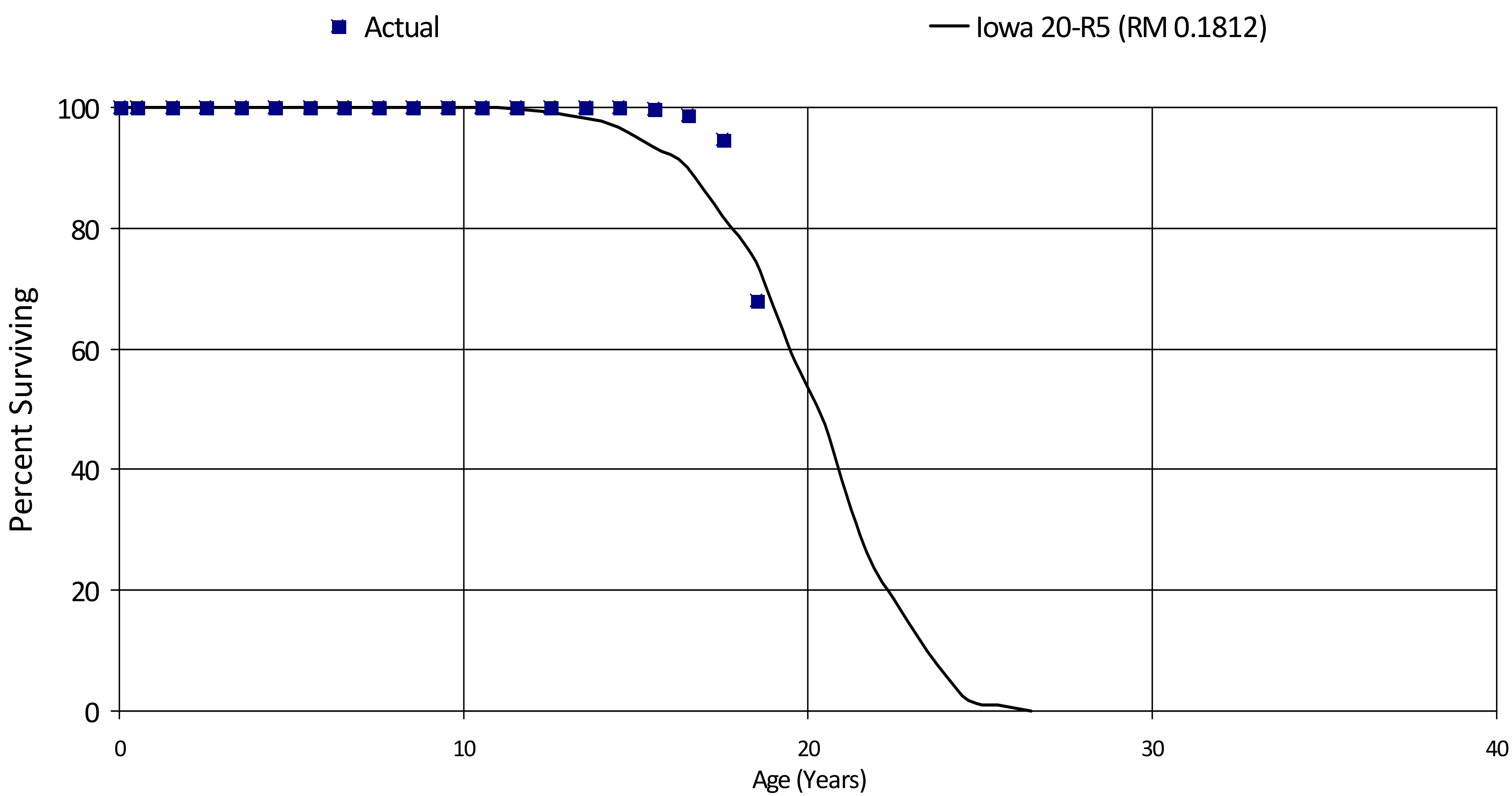
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	48,236,596	0	0.00000	1.00000	100.00
0.5	46,474,917	0	0.00000	1.00000	100.00
1.5	46,436,669	0	0.00000	1.00000	100.00
2.5	46,409,296	0	0.00000	1.00000	100.00
3.5	43,610,174	44,840	0.00103	0.99897	100.00
4.5	35,694,603	669,669	0.01876	0.98124	99.90
5.5	15,182,793	970,925	0.06395	0.93605	98.03
6.5	11,616,309	0	0.00000	1.00000	91.76
7.5	5,985,467	0	0.00000	1.00000	91.76
8.5	894,016	0	0.00000	1.00000	91.76
	Totals:	1,685,434			

BC Hydro Power Authority

Account 68202 - Terminal Unit, Remote (Slave)

Placement Band - 1997 - 2020 Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68202 - Terminal Unit, Remote (Slave)

Placement Band - 1997 - 2020   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

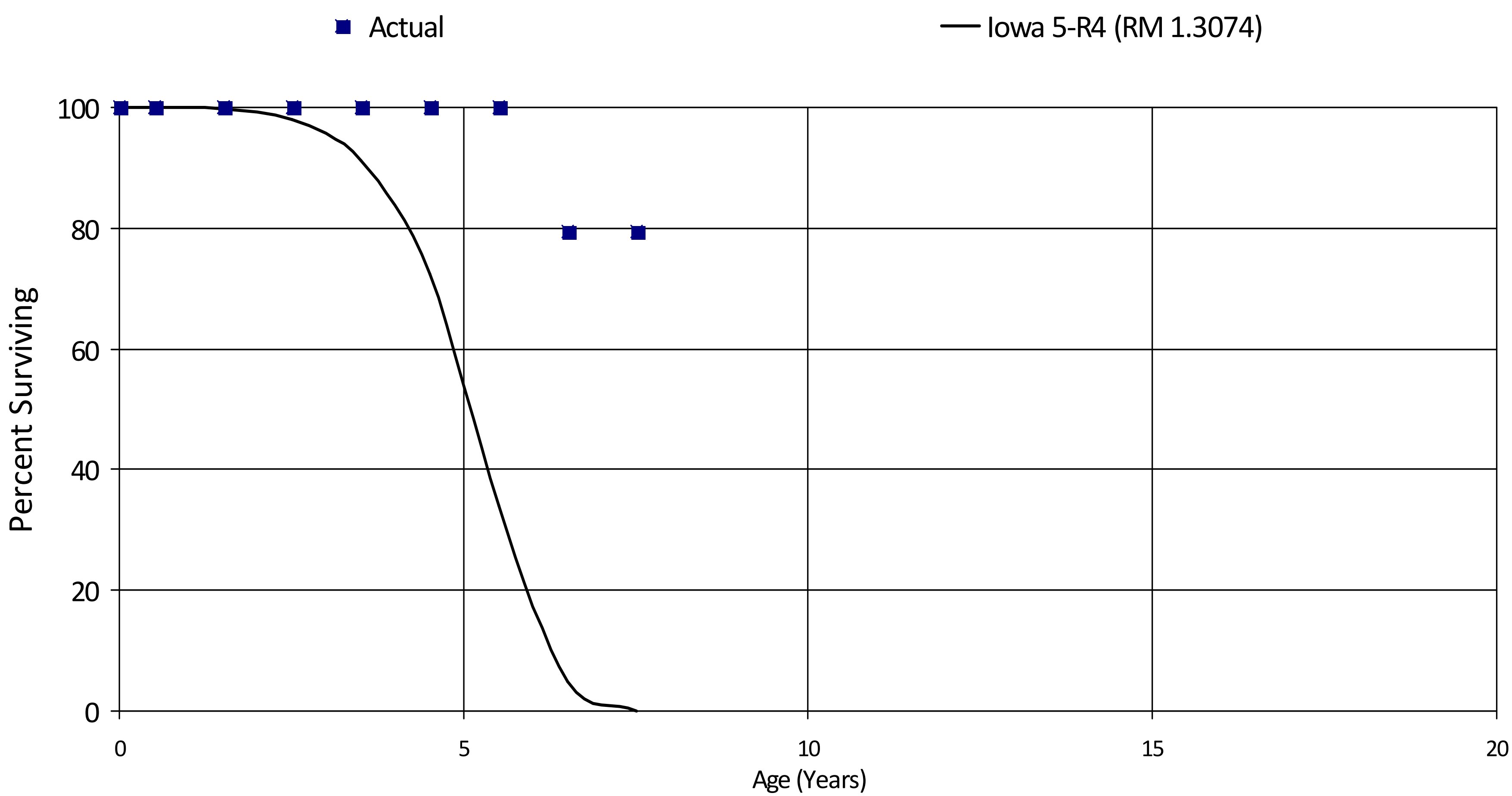
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	38,693,300	0	0.00000	1.00000	100.00
0.5	37,663,746	0	0.00000	1.00000	100.00
1.5	35,969,218	0	0.00000	1.00000	100.00
2.5	34,423,710	0	0.00000	1.00000	100.00
3.5	28,524,669	0	0.00000	1.00000	100.00
4.5	21,098,706	0	0.00000	1.00000	100.00
5.5	19,632,856	0	0.00000	1.00000	100.00
6.5	18,876,152	0	0.00000	1.00000	100.00
7.5	18,313,384	0	0.00000	1.00000	100.00
8.5	15,715,692	0	0.00000	1.00000	100.00
9.5	13,692,460	0	0.00000	1.00000	100.00
10.5	11,399,102	0	0.00000	1.00000	100.00
11.5	7,431,350	0	0.00000	1.00000	100.00
12.5	5,769,129	0	0.00000	1.00000	100.00
13.5	4,307,379	0	0.00000	1.00000	100.00
14.5	2,790,616	4,246	0.00152	0.99848	100.00
15.5	2,199,076	23,898	0.01087	0.98913	99.85
16.5	1,721,818	71,510	0.04153	0.95847	98.76
17.5	887,419	248,888	0.28046	0.71954	94.66
18.5	573,138	451,367	0.78754	0.21246	68.11
	Totals:	799,909			

BC Hydro Power Authority

Account 68203 - Integrated Control / Data (Icda)

Placement Band - 1996 - 2020   Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68203 - Integrated Control / Data (Icda)

Placement Band - 1996 - 2020   Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

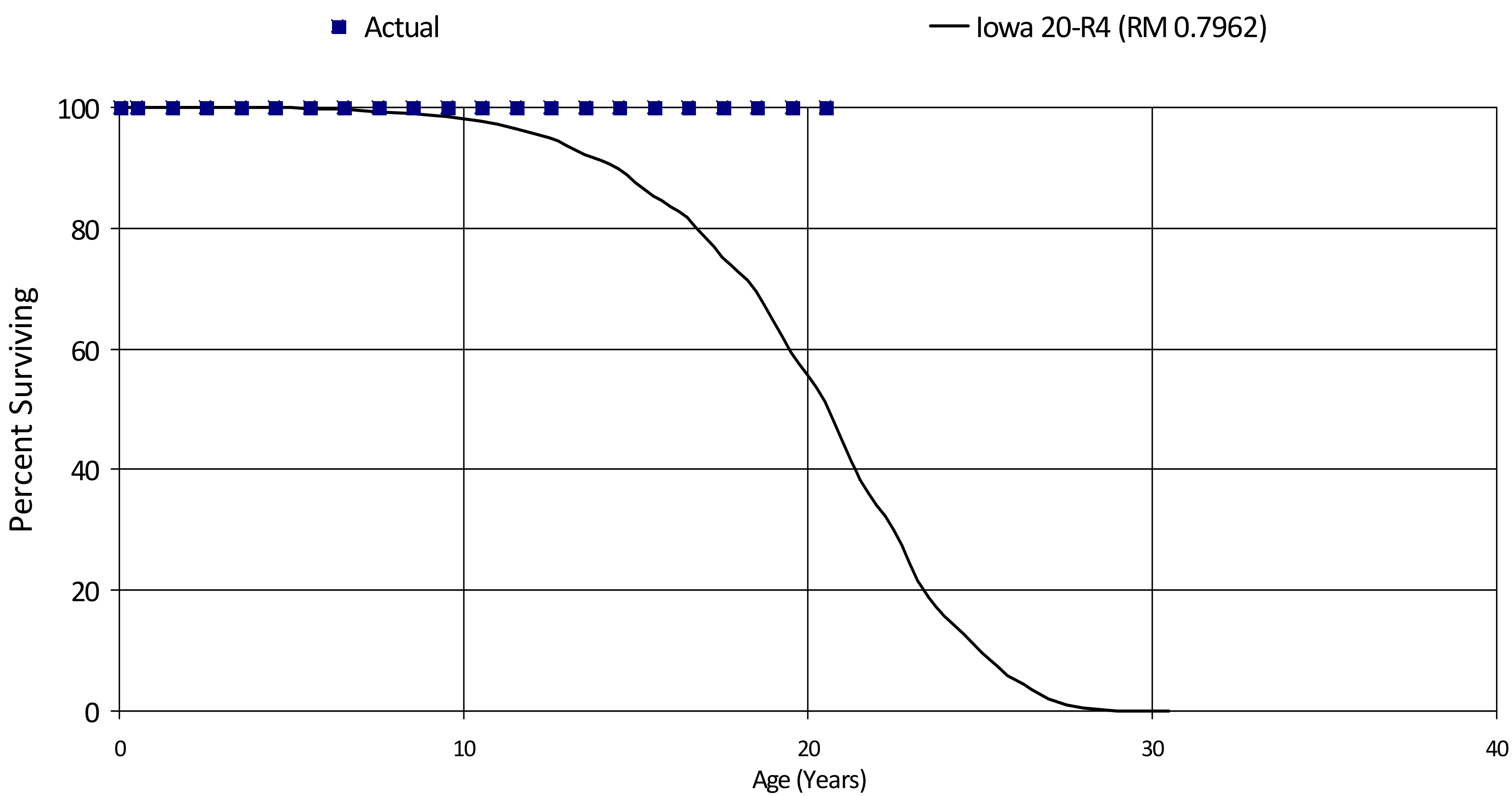
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	967,413	0	0.00000	1.00000	100.00
0.5	946,088	0	0.00000	1.00000	100.00
1.5	946,088	0	0.00000	1.00000	100.00
2.5	946,088	0	0.00000	1.00000	100.00
3.5	946,088	0	0.00000	1.00000	100.00
4.5	594,177	0	0.00000	1.00000	100.00
5.5	594,177	121,975	0.20528	0.79472	100.00
6.5	472,202	0	0.00000	1.00000	79.47
7.5	425,593	0	0.00000	1.00000	79.47
	Totals:	121,975			

BC Hydro Power Authority

Account 68204 - Distributed Control System

Placement Band - 1996 - 2020 Experience Band - 2019 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68204 - Distributed Control System

Placement Band - 1996 - 2020   Experience Band - 2019 - 2020

RETIREMENT RATE ANALYSIS

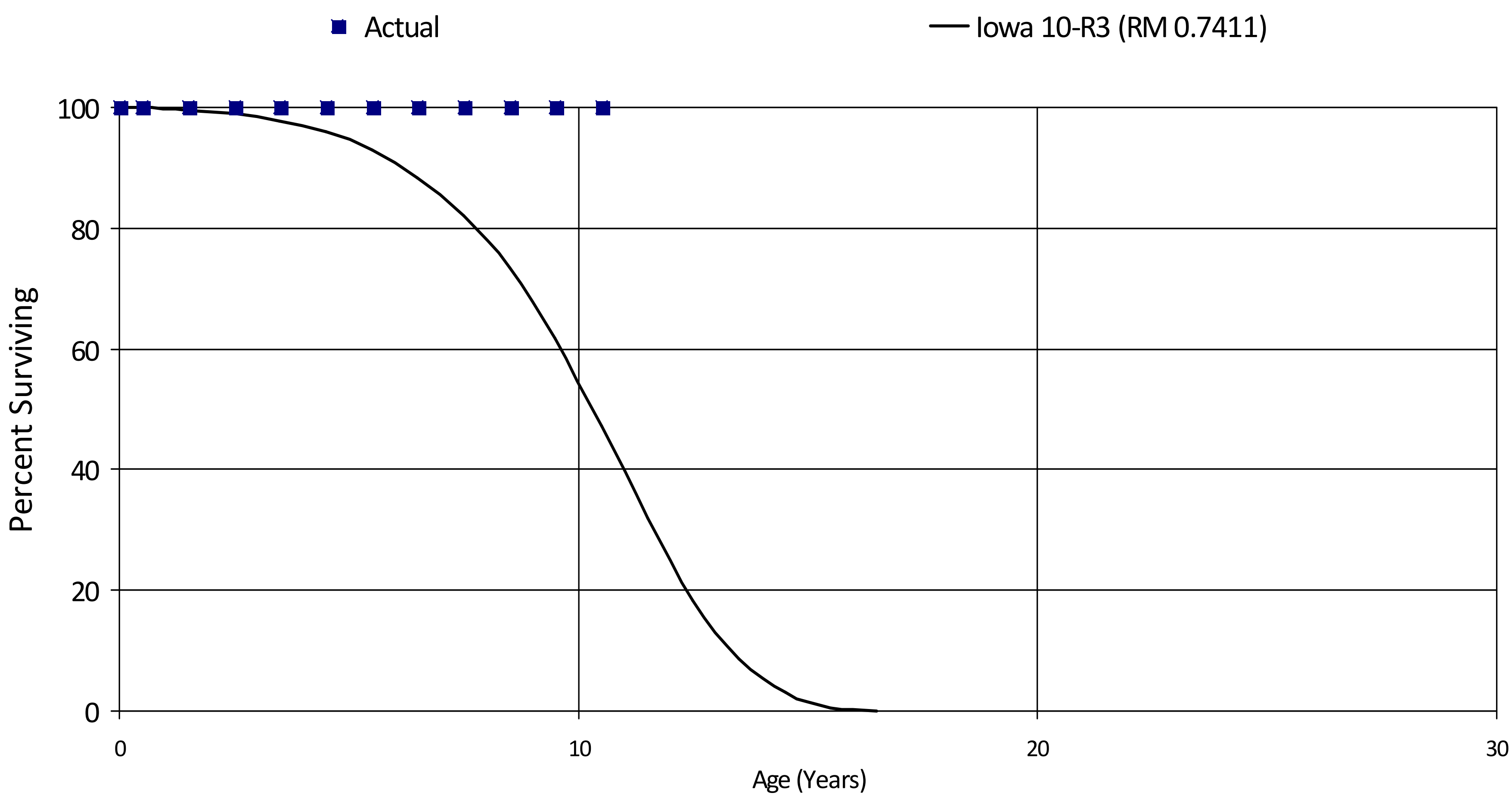
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	24,937,216	0	0.00000	1.00000	100.00
0.5	18,392,301	0	0.00000	1.00000	100.00
1.5	14,430,976	0	0.00000	1.00000	100.00
2.5	9,306,536	0	0.00000	1.00000	100.00
3.5	8,440,177	928	0.00011	0.99989	100.00
4.5	8,261,483	0	0.00000	1.00000	99.99
5.5	8,630,978	0	0.00000	1.00000	99.99
6.5	3,182,951	0	0.00000	1.00000	99.99
7.5	2,145,151	0	0.00000	1.00000	99.99
8.5	2,052,033	0	0.00000	1.00000	99.99
9.5	2,052,033	0	0.00000	1.00000	99.99
10.5	1,891,011	0	0.00000	1.00000	99.99
11.5	1,483,770	0	0.00000	1.00000	99.99
12.5	1,483,770	0	0.00000	1.00000	99.99
13.5	1,483,770	0	0.00000	1.00000	99.99
14.5	1,483,770	0	0.00000	1.00000	99.99
15.5	1,379,404	0	0.00000	1.00000	99.99
16.5	1,155,695	0	0.00000	1.00000	99.99
17.5	309,356	0	0.00000	1.00000	99.99
18.5	309,356	0	0.00000	1.00000	99.99
19.5	309,356	0	0.00000	1.00000	99.99
20.5	309,356	0	0.00000	1.00000	99.99
	Totals:	928			

BC Hydro Power Authority

Account 68205 - Global Positioning Equipment

Placement Band - 1996 - 2019 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68205 - Global Positioning Equipment

Placement Band - 1996 - 2019   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

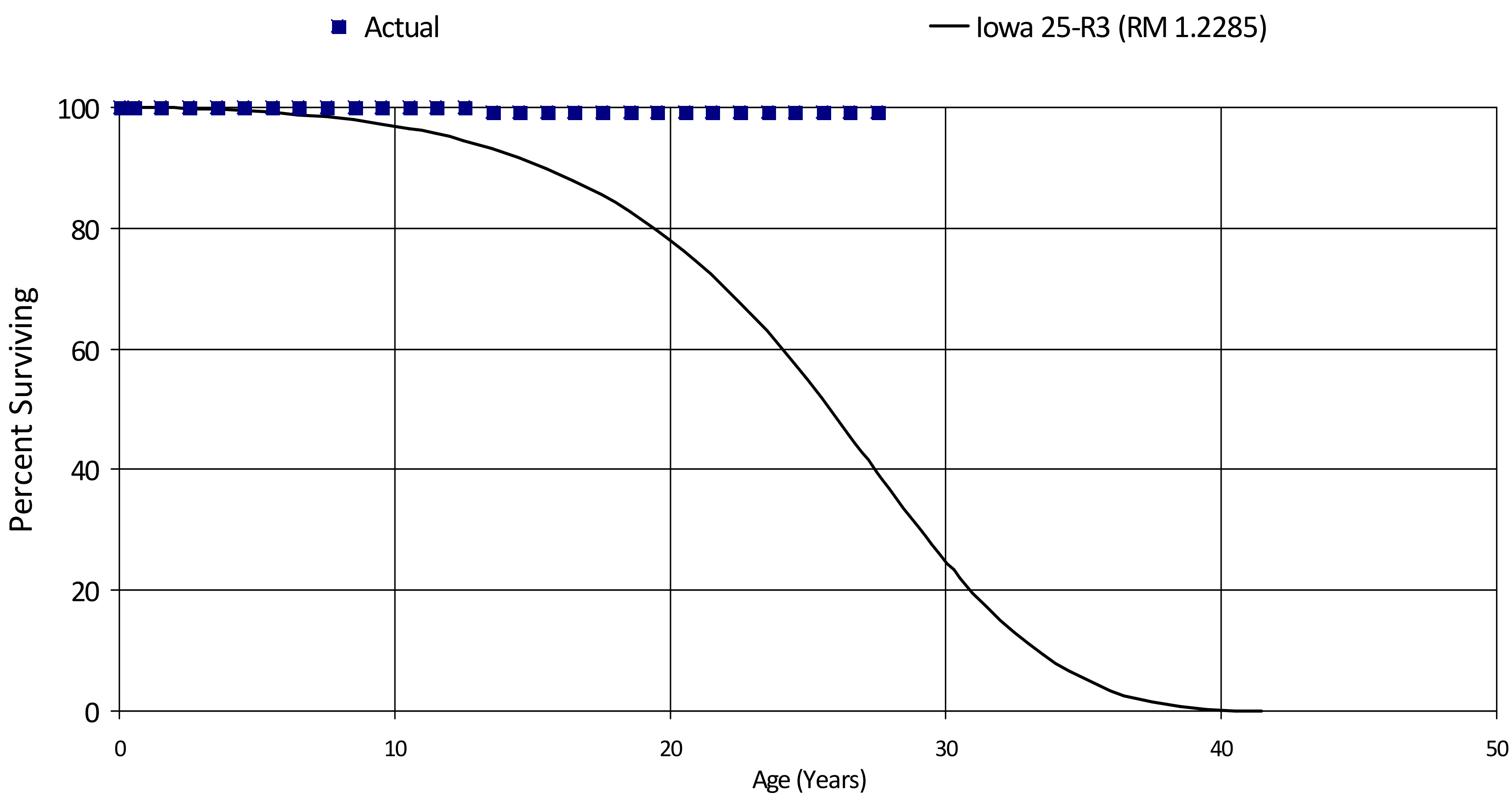
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	337,304	0	0.00000	1.00000	100.00
0.5	337,304	0	0.00000	1.00000	100.00
1.5	283,159	0	0.00000	1.00000	100.00
2.5	283,159	0	0.00000	1.00000	100.00
3.5	283,159	0	0.00000	1.00000	100.00
4.5	31,332	0	0.00000	1.00000	100.00
5.5	31,332	0	0.00000	1.00000	100.00
6.5	31,332	0	0.00000	1.00000	100.00
7.5	31,332	0	0.00000	1.00000	100.00
8.5	31,332	0	0.00000	1.00000	100.00
9.5	31,332	0	0.00000	1.00000	100.00
10.5	29,625	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 68301 - Radio, Microwave, Analog

Placement Band - 1992 - 2017 Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68301 - Radio, Microwave, Analog

Placement Band - 1992 - 2017 Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,147,362	0	0.00000	1.00000	100.00
0.5	2,147,362	0	0.00000	1.00000	100.00
1.5	2,147,362	0	0.00000	1.00000	100.00
2.5	2,147,362	0	0.00000	1.00000	100.00
3.5	1,967,073	0	0.00000	1.00000	100.00
4.5	1,967,073	0	0.00000	1.00000	100.00
5.5	1,967,073	0	0.00000	1.00000	100.00
6.5	1,967,073	0	0.00000	1.00000	100.00
7.5	1,967,073	0	0.00000	1.00000	100.00
8.5	1,967,073	0	0.00000	1.00000	100.00
9.5	811,739	0	0.00000	1.00000	100.00
10.5	804,115	0	0.00000	1.00000	100.00
11.5	791,217	0	0.00000	1.00000	100.00
12.5	791,217	6,926	0.00875	0.99125	100.00
13.5	784,290	0	0.00000	1.00000	99.12
14.5	784,290	0	0.00000	1.00000	99.12
15.5	784,290	0	0.00000	1.00000	99.12
16.5	784,290	0	0.00000	1.00000	99.12
17.5	632,173	0	0.00000	1.00000	99.12
18.5	592,655	0	0.00000	1.00000	99.12
19.5	592,655	0	0.00000	1.00000	99.12
20.5	388,291	0	0.00000	1.00000	99.12
21.5	270,703	0	0.00000	1.00000	99.12
22.5	270,703	0	0.00000	1.00000	99.12
23.5	254,924	0	0.00000	1.00000	99.12
24.5	254,924	0	0.00000	1.00000	99.12
25.5	254,924	0	0.00000	1.00000	99.12
26.5	242,602	0	0.00000	1.00000	99.12

BC Hydro Power Authority

Account 68301 - Radio, Microwave, Analog

Placement Band - 1992 - 2017   Experience Band - 2016 - 2020

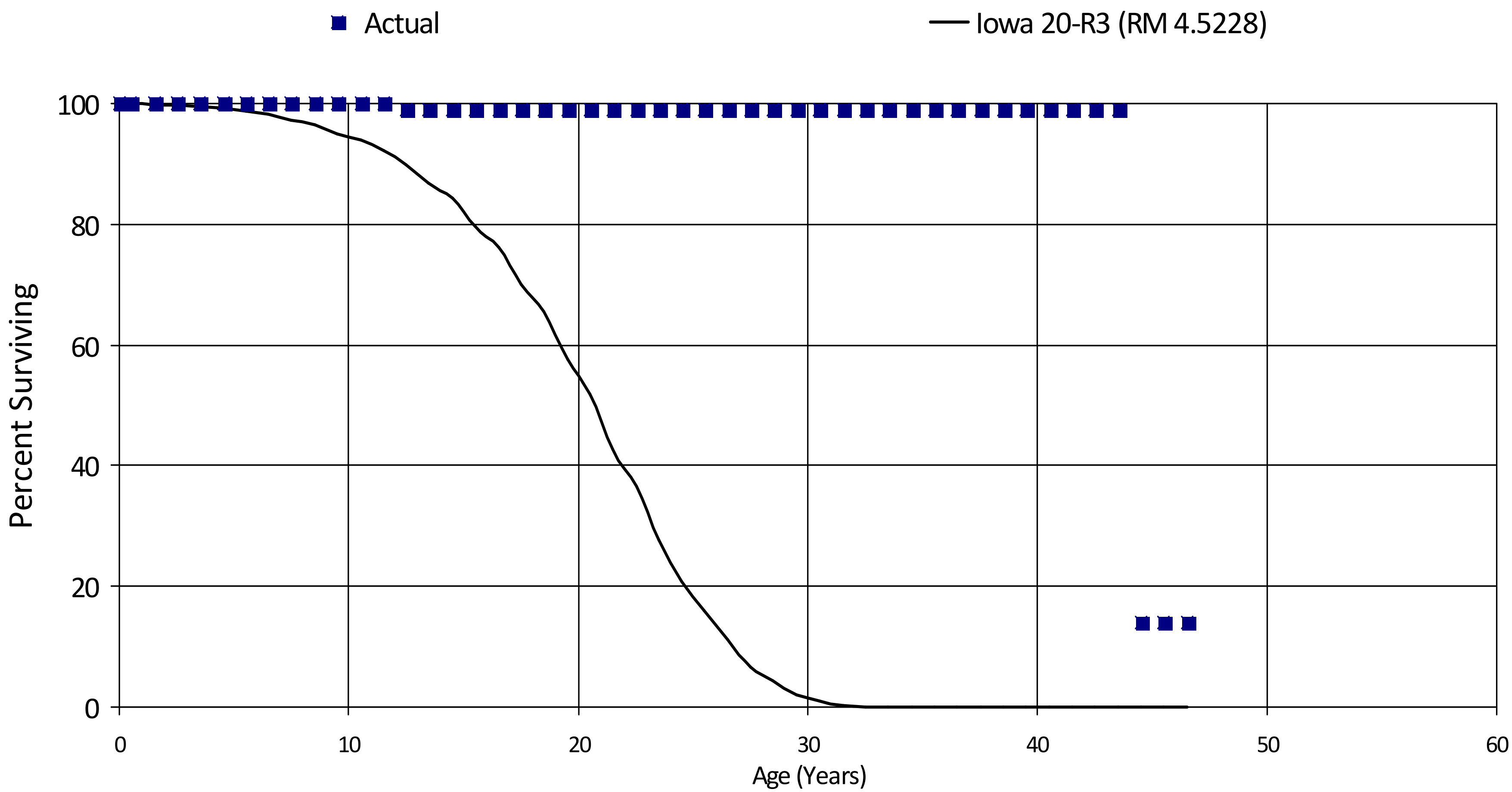
27.5	242,602	0	0.00000	1.00000	99.12
	Totals:	6,926			

BC Hydro Power Authority

Account 68302 - Radio, Microwave, Digital

Placement Band - 1966 - 2020 Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68302 - Radio, Microwave, Digital

Placement Band - 1966 - 2020 Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	44,302,213	0	0.00000	1.00000	100.00
0.5	44,080,958	0	0.00000	1.00000	100.00
1.5	43,339,311	0	0.00000	1.00000	100.00
2.5	41,403,629	0	0.00000	1.00000	100.00
3.5	37,826,070	0	0.00000	1.00000	100.00
4.5	34,890,810	0	0.00000	1.00000	100.00
5.5	34,727,546	0	0.00000	1.00000	100.00
6.5	33,417,084	0	0.00000	1.00000	100.00
7.5	32,800,685	0	0.00000	1.00000	100.00
8.5	28,496,866	0	0.00000	1.00000	100.00
9.5	23,530,297	0	0.00000	1.00000	100.00
10.5	23,183,336	0	0.00000	1.00000	100.00
11.5	22,850,363	236,664	0.01036	0.98964	100.00
12.5	21,148,723	0	0.00000	1.00000	98.96
13.5	20,205,483	0	0.00000	1.00000	98.96
14.5	19,852,451	0	0.00000	1.00000	98.96
15.5	8,563,310	0	0.00000	1.00000	98.96
16.5	6,333,434	0	0.00000	1.00000	98.96
17.5	6,333,434	0	0.00000	1.00000	98.96
18.5	6,333,434	0	0.00000	1.00000	98.96
19.5	4,328,250	0	0.00000	1.00000	98.96
20.5	4,011,286	0	0.00000	1.00000	98.96
21.5	4,011,286	0	0.00000	1.00000	98.96
22.5	4,011,286	0	0.00000	1.00000	98.96
23.5	4,011,286	0	0.00000	1.00000	98.96
24.5	4,011,286	0	0.00000	1.00000	98.96
25.5	4,011,286	0	0.00000	1.00000	98.96
26.5	4,000,870	0	0.00000	1.00000	98.96

BC Hydro Power Authority

Account 68302 - Radio, Microwave, Digital

Placement Band - 1966 - 2020   Experience Band - 2011 - 2020

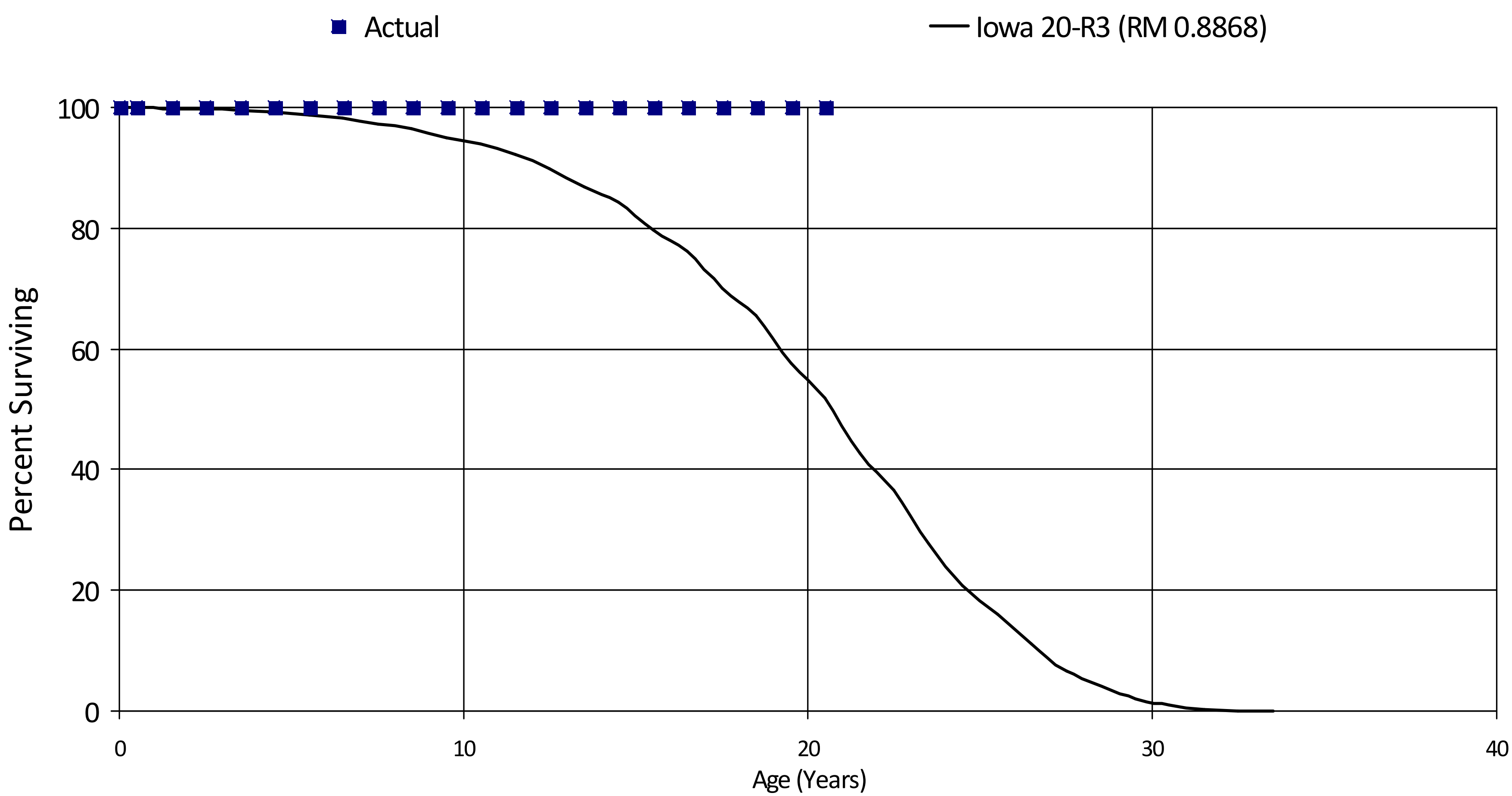
27.5	4,000,870	0	0.00000	1.00000	98.96
28.5	4,000,870	0	0.00000	1.00000	98.96
29.5	4,000,870	0	0.00000	1.00000	98.96
30.5	4,000,870	0	0.00000	1.00000	98.96
31.5	4,000,870	0	0.00000	1.00000	98.96
32.5	4,000,870	0	0.00000	1.00000	98.96
33.5	4,000,870	0	0.00000	1.00000	98.96
34.5	4,000,870	0	0.00000	1.00000	98.96
35.5	4,000,870	0	0.00000	1.00000	98.96
36.5	4,000,870	0	0.00000	1.00000	98.96
37.5	3,884,273	0	0.00000	1.00000	98.96
38.5	3,884,273	0	0.00000	1.00000	98.96
39.5	3,884,273	0	0.00000	1.00000	98.96
40.5	3,884,273	0	0.00000	1.00000	98.96
41.5	3,884,273	0	0.00000	1.00000	98.96
42.5	3,884,273	0	0.00000	1.00000	98.96
43.5	3,884,273	3,339,680	0.85980	0.14020	98.96
44.5	544,593	0	0.00000	1.00000	13.87
45.5	544,593	0	0.00000	1.00000	13.87
46.5	544,593	0	0.00000	1.00000	13.87
	Totals:	3,576,344			

BC Hydro Power Authority

Account 68303 - Microwave, Conversion Only

Placement Band - 1992 - 2001   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68303 - Microwave, Conversion Only

Placement Band - 1992 - 2001   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	20,609	0	0.00000	1.00000	100.00
0.5	20,609	0	0.00000	1.00000	100.00
1.5	20,609	0	0.00000	1.00000	100.00
2.5	20,609	0	0.00000	1.00000	100.00
3.5	20,609	0	0.00000	1.00000	100.00
4.5	20,609	0	0.00000	1.00000	100.00
5.5	20,609	0	0.00000	1.00000	100.00
6.5	20,609	0	0.00000	1.00000	100.00
7.5	20,609	0	0.00000	1.00000	100.00
8.5	20,609	0	0.00000	1.00000	100.00
9.5	20,609	0	0.00000	1.00000	100.00
10.5	20,609	0	0.00000	1.00000	100.00
11.5	20,609	0	0.00000	1.00000	100.00
12.5	20,609	0	0.00000	1.00000	100.00
13.5	20,609	0	0.00000	1.00000	100.00
14.5	20,609	0	0.00000	1.00000	100.00
15.5	20,609	0	0.00000	1.00000	100.00
16.5	20,609	0	0.00000	1.00000	100.00
17.5	20,609	0	0.00000	1.00000	100.00
18.5	20,609	0	0.00000	1.00000	100.00
19.5	18,634	0	0.00000	1.00000	100.00
20.5	14,702	14,702	1.00002	-0.00002	100.00
	Totals:	14,702			

BC Hydro Power Authority

Account 68401 - Multiplex Device, Analog

Placement Band - 2012 - 2019   Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves

BC Hydro Power Authority

Account 68401 - Multiplex Device, Analog

Placement Band - 2012 - 2019   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

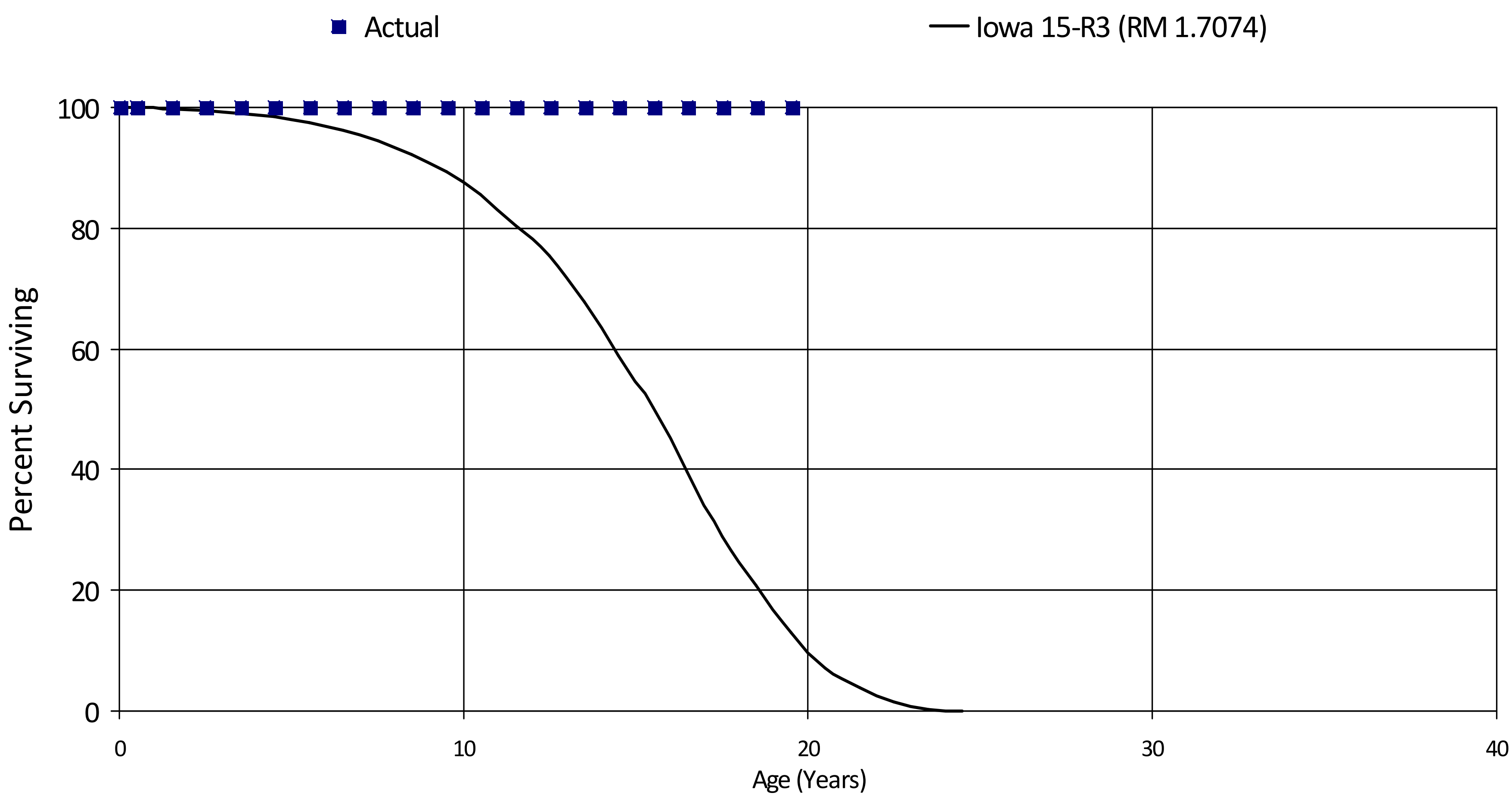
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	37,878	0	0.00000	1.00000	100.00
0.5	37,878	0	0.00000	1.00000	100.00
1.5	23,892	0	0.00000	1.00000	100.00
2.5	23,892	0	0.00000	1.00000	100.00
3.5	23,892	0	0.00000	1.00000	100.00
4.5	23,892	23,892	0.99999	0.00001	100.00
	Totals:	23,892			

BC Hydro Power Authority

Account 68402 - Multiplex Device, Digital

Placement Band - 1995 - 2020   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68402 - Multiplex Device, Digital

Placement Band - 1995 - 2020   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

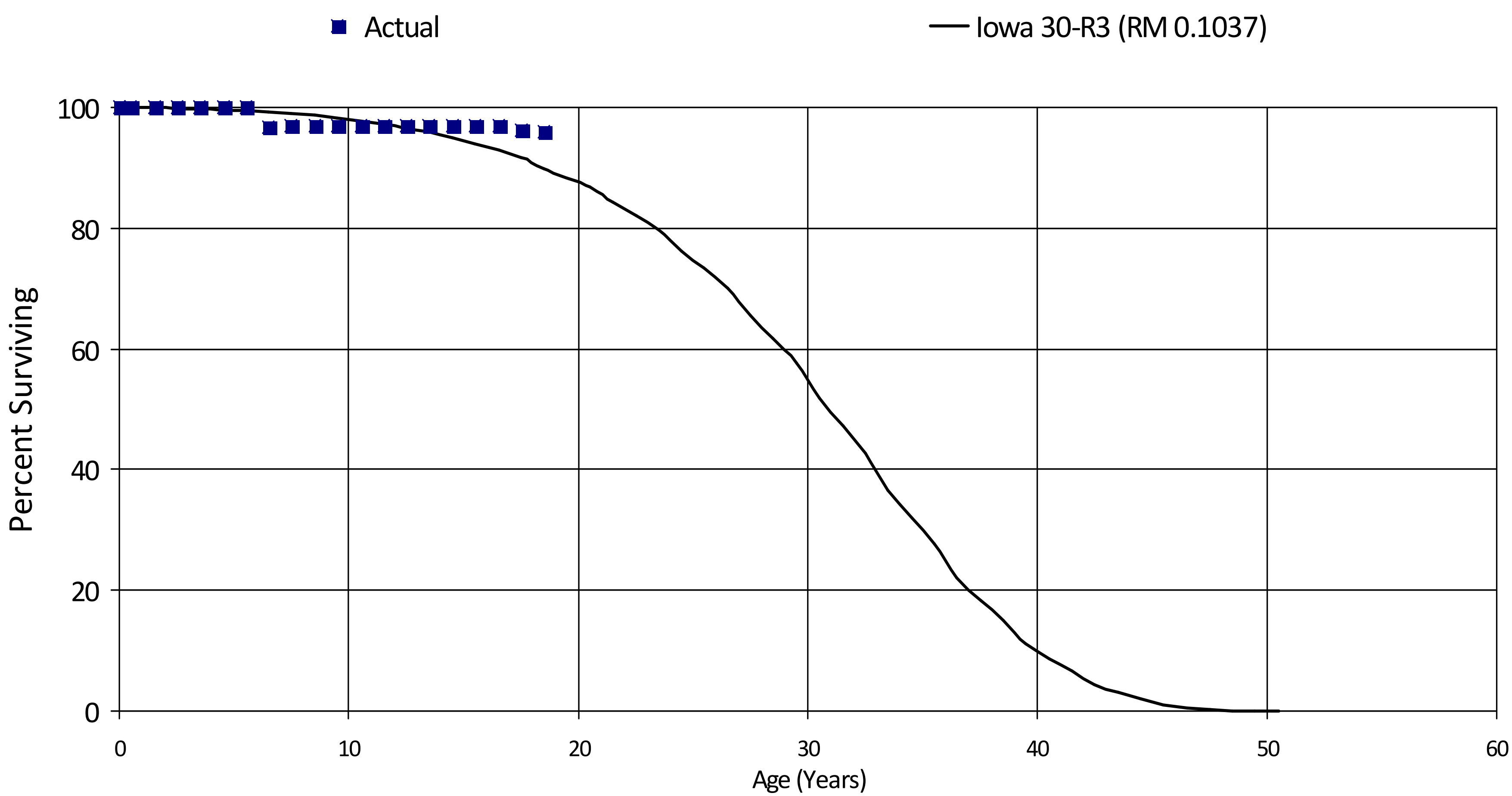
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	22,839,361	0	0.00000	1.00000	100.00
0.5	22,751,325	0	0.00000	1.00000	100.00
1.5	19,894,248	0	0.00000	1.00000	100.00
2.5	16,248,127	0	0.00000	1.00000	100.00
3.5	14,664,279	0	0.00000	1.00000	100.00
4.5	12,165,971	0	0.00000	1.00000	100.00
5.5	11,758,019	0	0.00000	1.00000	100.00
6.5	9,009,128	0	0.00000	1.00000	100.00
7.5	8,191,572	0	0.00000	1.00000	100.00
8.5	7,104,765	0	0.00000	1.00000	100.00
9.5	6,271,842	0	0.00000	1.00000	100.00
10.5	6,235,376	0	0.00000	1.00000	100.00
11.5	5,522,283	0	0.00000	1.00000	100.00
12.5	5,176,335	0	0.00000	1.00000	100.00
13.5	4,759,643	0	0.00000	1.00000	100.00
14.5	4,226,092	0	0.00000	1.00000	100.00
15.5	2,991,372	0	0.00000	1.00000	100.00
16.5	1,036,368	0	0.00000	1.00000	100.00
17.5	888,942	0	0.00000	1.00000	100.00
18.5	888,942	0	0.00000	1.00000	100.00
19.5	229,919	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 68501 - Radio Systems, Uhf/Vhff

Placement Band - 2001 - 2018 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68501 - Radio Systems, Uhf/Vhff

Placement Band - 2001 - 2018   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

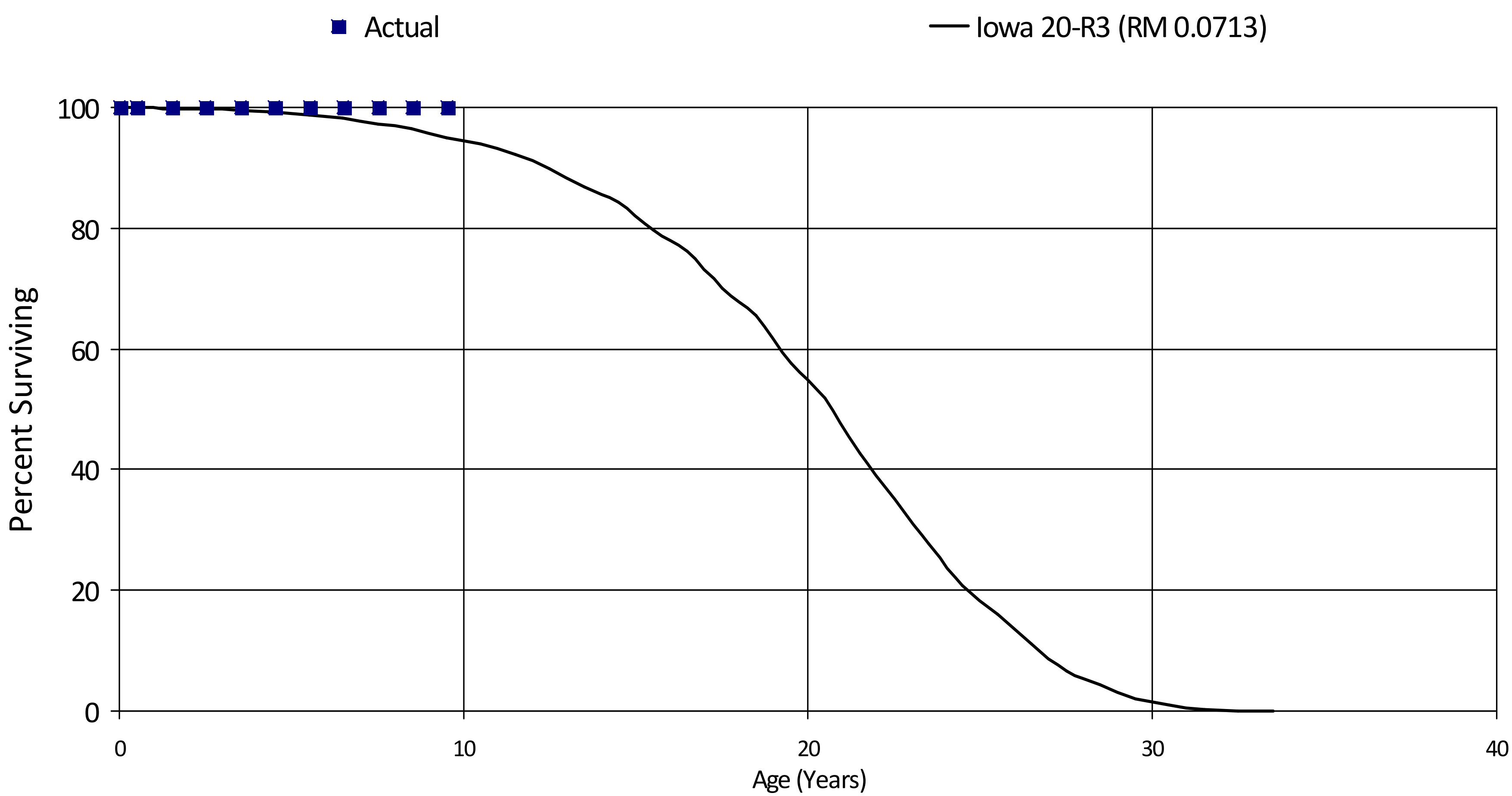
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	19,753,178	0	0.00000	1.00000	100.00
0.5	19,753,178	0	0.00000	1.00000	100.00
1.5	19,753,178	0	0.00000	1.00000	100.00
2.5	19,494,798	0	0.00000	1.00000	100.00
3.5	19,469,291	-7,886	-0.00041	1.00041	100.00
4.5	18,722,438	0	0.00000	1.00000	100.04
5.5	18,575,519	636,326	0.03426	0.96574	100.04
6.5	8,149,334	-29,780	-0.00365	1.00365	96.61
7.5	7,942,696	0	0.00000	1.00000	96.96
8.5	6,343,710	75	0.00001	0.99999	96.96
9.5	6,263,928	0	0.00000	1.00000	96.96
10.5	3,412,525	0	0.00000	1.00000	96.96
11.5	2,524,187	0	0.00000	1.00000	96.96
12.5	2,392,706	0	0.00000	1.00000	96.96
13.5	2,392,706	0	0.00000	1.00000	96.96
14.5	1,489,398	0	0.00000	1.00000	96.96
15.5	902,157	0	0.00000	1.00000	96.96
16.5	845,993	5,766	0.00682	0.99318	96.96
17.5	790,703	2,280	0.00288	0.99712	96.30
18.5	340,288	0	0.00000	1.00000	96.02
	Totals:	606,781			

BC Hydro Power Authority

Account 68503 - Radio Equipment, Protection

Placement Band - 1998 - 2018 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68503 - Radio Equipment, Protection

Placement Band - 1998 - 2018   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

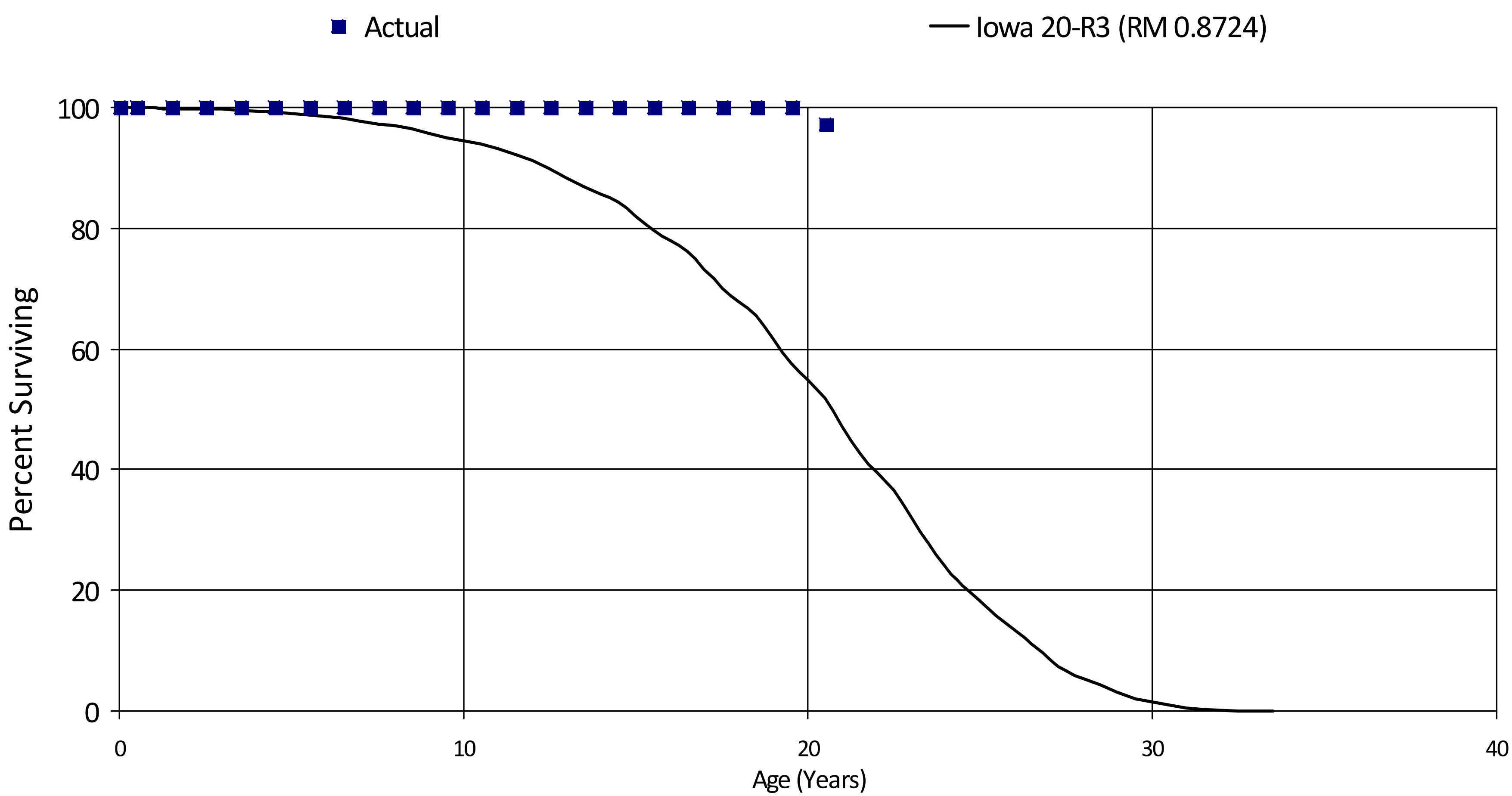
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	4,699,561	0	0.00000	1.00000	100.00
0.5	4,699,561	0	0.00000	1.00000	100.00
1.5	4,699,561	0	0.00000	1.00000	100.00
2.5	4,681,408	0	0.00000	1.00000	100.00
3.5	4,681,408	0	0.00000	1.00000	100.00
4.5	3,673,558	0	0.00000	1.00000	100.00
5.5	2,886,700	0	0.00000	1.00000	100.00
6.5	2,255,971	0	0.00000	1.00000	100.00
7.5	1,856,596	0	0.00000	1.00000	100.00
8.5	825,511	0	0.00000	1.00000	100.00
9.5	462,803	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 68601 - Protection Tone System

Placement Band - 1995 - 2019 Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68601 - Protection Tone System

Placement Band - 1995 - 2019   Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

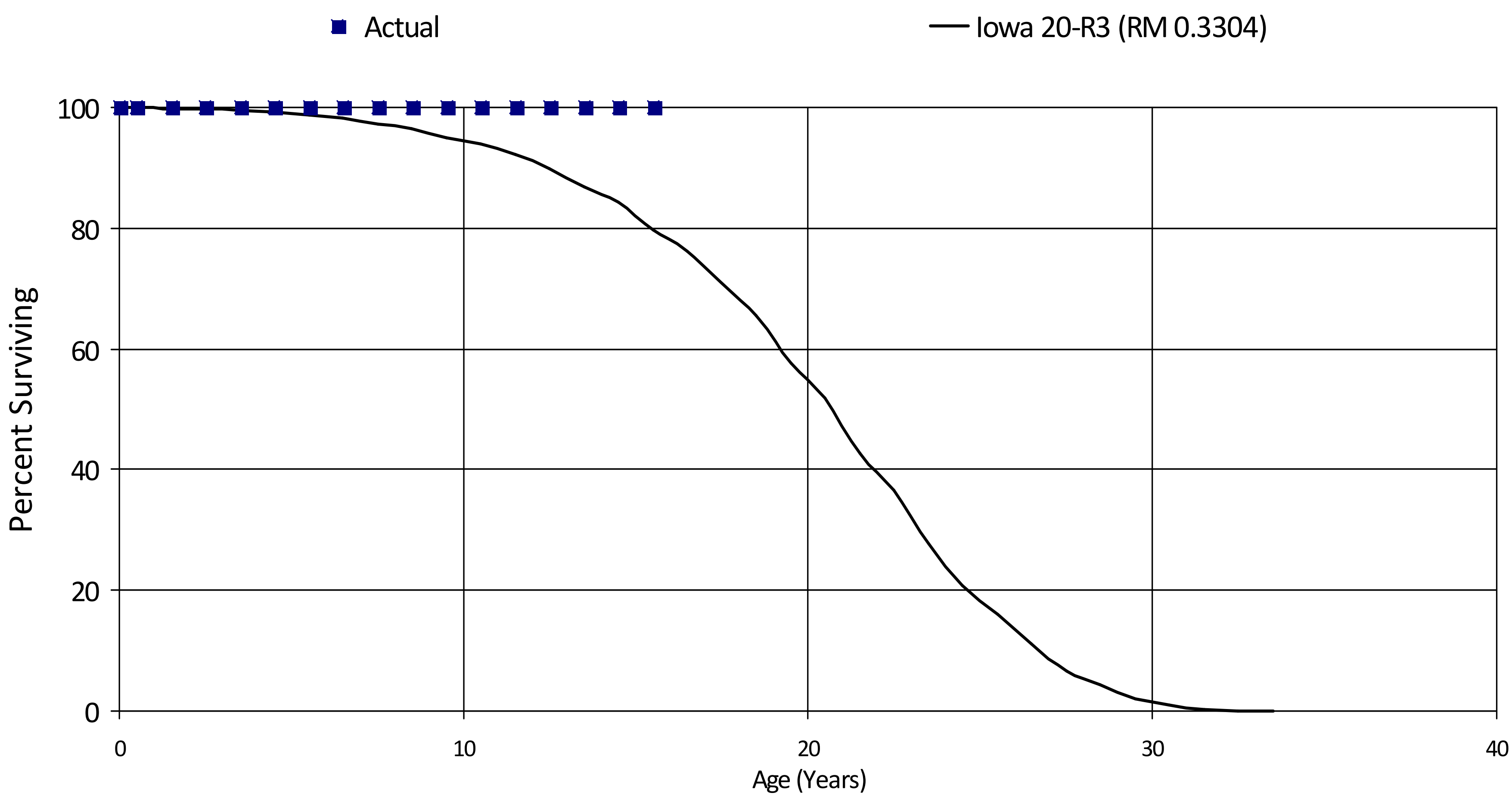
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	26,538,853	0	0.00000	1.00000	100.00
0.5	26,538,853	0	0.00000	1.00000	100.00
1.5	26,444,976	0	0.00000	1.00000	100.00
2.5	24,228,368	0	0.00000	1.00000	100.00
3.5	21,674,945	0	0.00000	1.00000	100.00
4.5	20,238,457	0	0.00000	1.00000	100.00
5.5	19,742,361	0	0.00000	1.00000	100.00
6.5	16,801,971	0	0.00000	1.00000	100.00
7.5	13,071,126	0	0.00000	1.00000	100.00
8.5	10,669,974	0	0.00000	1.00000	100.00
9.5	7,704,215	0	0.00000	1.00000	100.00
10.5	5,949,097	0	0.00000	1.00000	100.00
11.5	3,598,613	0	0.00000	1.00000	100.00
12.5	3,303,192	0	0.00000	1.00000	100.00
13.5	2,938,855	0	0.00000	1.00000	100.00
14.5	2,721,320	0	0.00000	1.00000	100.00
15.5	2,246,363	0	0.00000	1.00000	100.00
16.5	1,573,505	0	0.00000	1.00000	100.00
17.5	928,270	0	0.00000	1.00000	100.00
18.5	669,453	0	0.00000	1.00000	100.00
19.5	562,693	15,307	0.02720	0.97280	100.00
20.5	467,251	327,874	0.70171	0.29829	97.28
	Totals:	343,181			

BC Hydro Power Authority

Account 68602 - Digital Teleprotection System

Placement Band - 2003 - 2017 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68602 - Digital Teleprotection System

Placement Band - 2003 - 2017 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

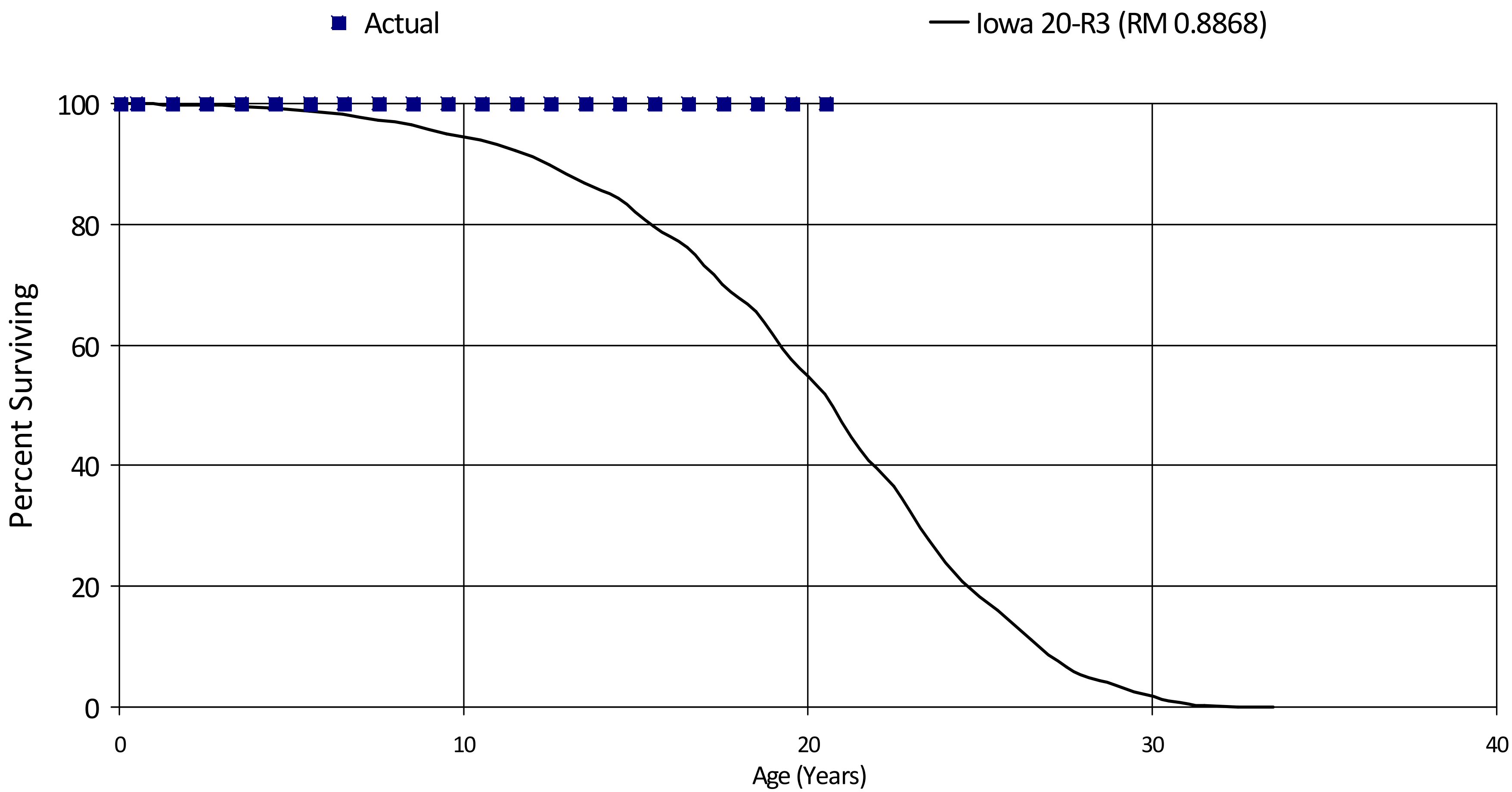
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	7,346,672	0	0.00000	1.00000	100.00
0.5	7,346,672	0	0.00000	1.00000	100.00
1.5	7,346,672	0	0.00000	1.00000	100.00
2.5	7,346,672	0	0.00000	1.00000	100.00
3.5	6,255,247	0	0.00000	1.00000	100.00
4.5	5,840,150	0	0.00000	1.00000	100.00
5.5	5,384,402	0	0.00000	1.00000	100.00
6.5	5,338,034	0	0.00000	1.00000	100.00
7.5	4,275,337	0	0.00000	1.00000	100.00
8.5	2,963,096	0	0.00000	1.00000	100.00
9.5	1,460,925	0	0.00000	1.00000	100.00
10.5	1,460,925	0	0.00000	1.00000	100.00
11.5	1,460,925	0	0.00000	1.00000	100.00
12.5	1,454,801	0	0.00000	1.00000	100.00
13.5	1,291,254	0	0.00000	1.00000	100.00
14.5	626,886	0	0.00000	1.00000	100.00
15.5	466,856	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 68701 - Wave Trap / Line Trap

Placement Band - 1991 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68701 - Wave Trap / Line Trap

Placement Band - 1991 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

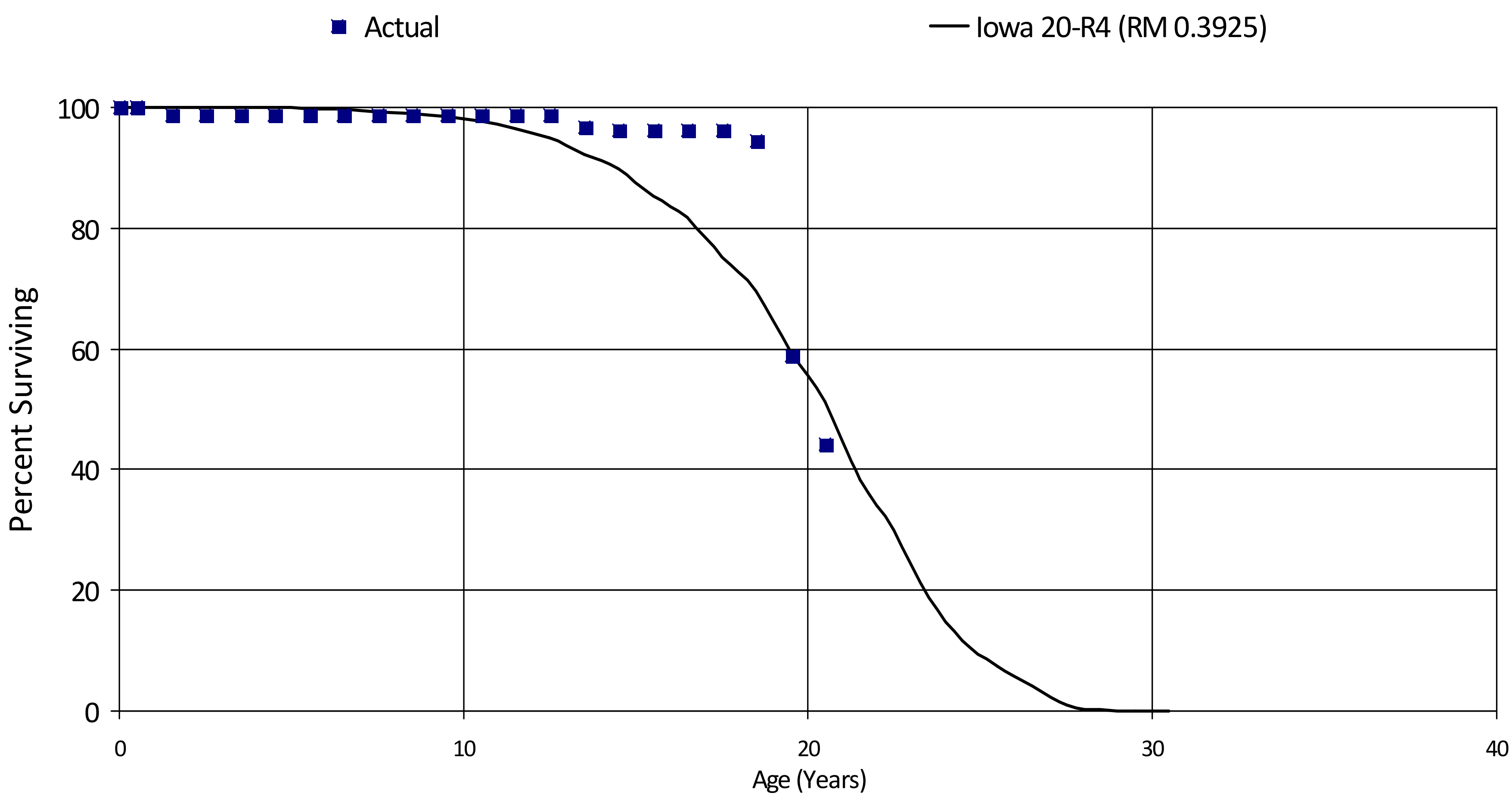
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,873,686	0	0.00000	1.00000	100.00
0.5	1,786,072	0	0.00000	1.00000	100.00
1.5	1,786,072	0	0.00000	1.00000	100.00
2.5	1,627,624	0	0.00000	1.00000	100.00
3.5	1,589,945	0	0.00000	1.00000	100.00
4.5	1,589,945	0	0.00000	1.00000	100.00
5.5	1,530,339	0	0.00000	1.00000	100.00
6.5	1,326,085	0	0.00000	1.00000	100.00
7.5	1,277,925	0	0.00000	1.00000	100.00
8.5	1,218,050	0	0.00000	1.00000	100.00
9.5	643,352	0	0.00000	1.00000	100.00
10.5	538,883	0	0.00000	1.00000	100.00
11.5	407,052	0	0.00000	1.00000	100.00
12.5	398,949	0	0.00000	1.00000	100.00
13.5	342,058	0	0.00000	1.00000	100.00
14.5	257,755	0	0.00000	1.00000	100.00
15.5	114,402	0	0.00000	1.00000	100.00
16.5	103,054	0	0.00000	1.00000	100.00
17.5	85,065	0	0.00000	1.00000	100.00
18.5	38,057	0	0.00000	1.00000	100.00
19.5	34,692	0	0.00000	1.00000	100.00
20.5	30,564	21,046	0.68859	0.31141	100.00
	Totals:	21,046			

BC Hydro Power Authority

Account 68801 - Fibre Optic System

Placement Band - 1994 - 2020   Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68801 - Fibre Optic System

Placement Band - 1994 - 2020   Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

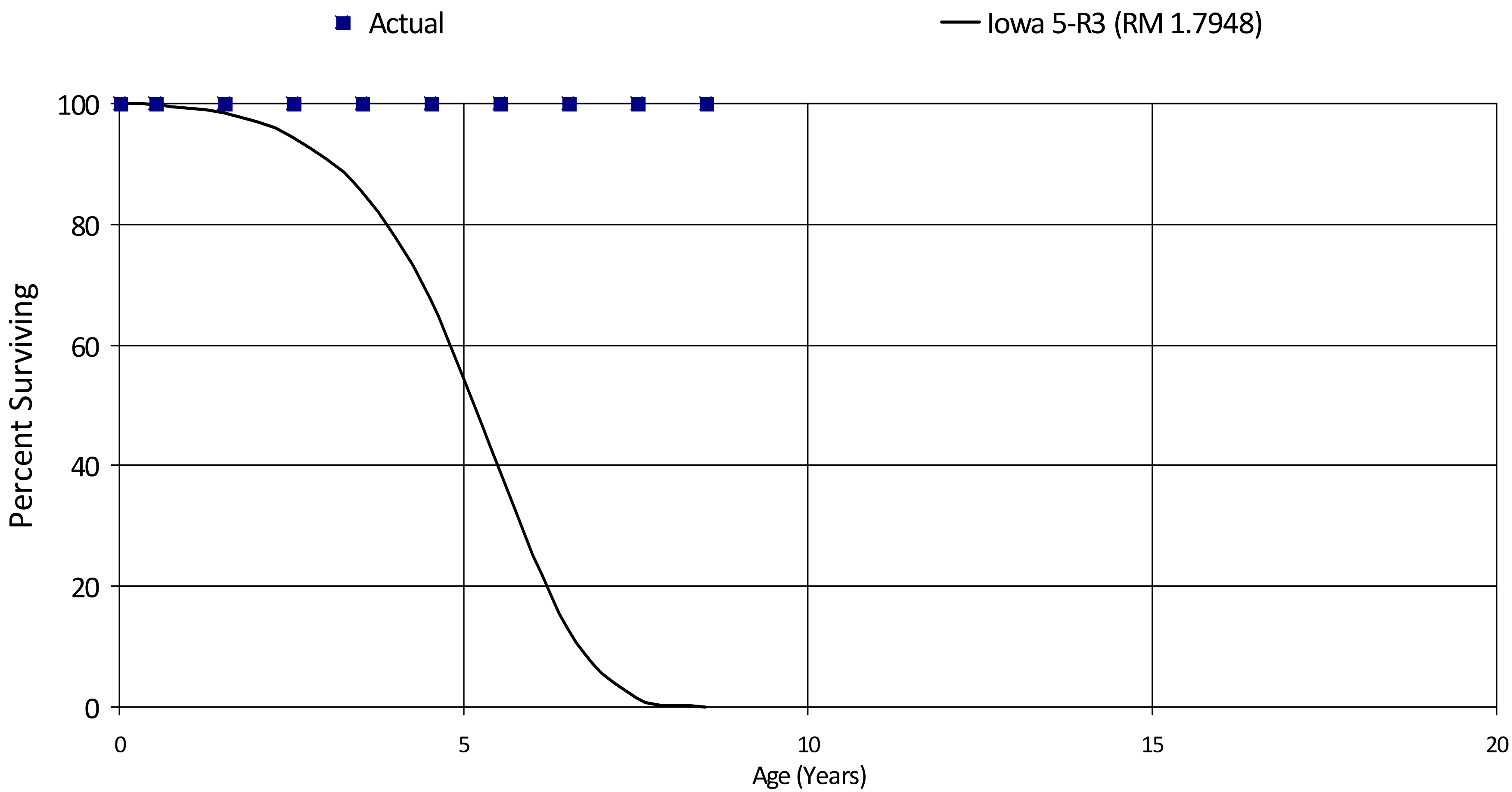
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	32,084,549	0	0.00000	1.00000	100.00
0.5	32,017,194	411,649	0.01286	0.98714	100.00
1.5	30,430,505	0	0.00000	1.00000	98.71
2.5	29,983,402	0	0.00000	1.00000	98.71
3.5	29,521,398	0	0.00000	1.00000	98.71
4.5	25,999,559	0	0.00000	1.00000	98.71
5.5	20,633,366	0	0.00000	1.00000	98.71
6.5	13,057,148	0	0.00000	1.00000	98.71
7.5	11,541,368	0	0.00000	1.00000	98.71
8.5	9,000,588	0	0.00000	1.00000	98.71
9.5	8,652,424	0	0.00000	1.00000	98.71
10.5	8,085,873	0	0.00000	1.00000	98.71
11.5	5,694,930	0	0.00000	1.00000	98.71
12.5	4,901,978	103,032	0.02102	0.97898	98.71
13.5	4,752,607	18,783	0.00395	0.99605	96.64
14.5	3,972,380	0	0.00000	1.00000	96.26
15.5	3,474,472	0	0.00000	1.00000	96.26
16.5	1,806,409	0	0.00000	1.00000	96.26
17.5	1,537,022	29,155	0.01897	0.98103	96.26
18.5	1,444,702	544,494	0.37689	0.62311	94.43
19.5	727,054	181,017	0.24897	0.75103	58.84
20.5	546,036	434,038	0.79489	0.20511	44.19
	Totals:	1,722,168			

BC Hydro Power Authority

Account 68903 - Telephone Equipment, Monitoring System

Placement Band - 2003 - 2019   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 68903 - Telephone Equipment, Monitoring System

Placement Band - 2003 - 2019   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

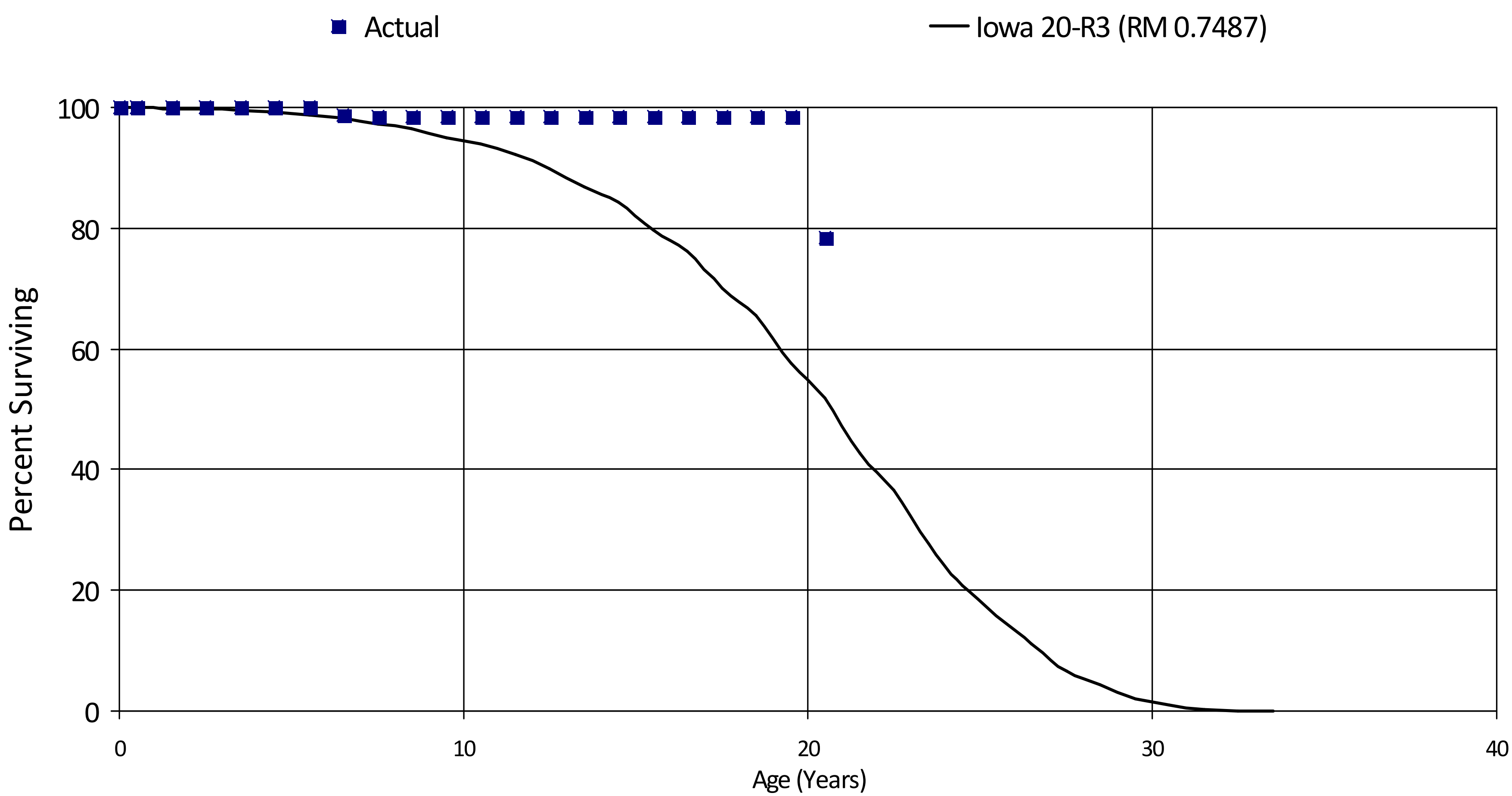
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,085,655	0	0.00000	1.00000	100.00
0.5	2,085,655	0	0.00000	1.00000	100.00
1.5	1,810,730	0	0.00000	1.00000	100.00
2.5	1,800,992	0	0.00000	1.00000	100.00
3.5	1,507,646	0	0.00000	1.00000	100.00
4.5	777,325	0	0.00000	1.00000	100.00
5.5	136,300	0	0.00000	1.00000	100.00
6.5	136,300	0	0.00000	1.00000	100.00
7.5	65,849	0	0.00000	1.00000	100.00
8.5	65,849	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 70001 - Cable, Entrance Protection

Placement Band - 1995 - 2020   Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 70001 - Cable, Entrance Protection

Placement Band - 1995 - 2020   Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

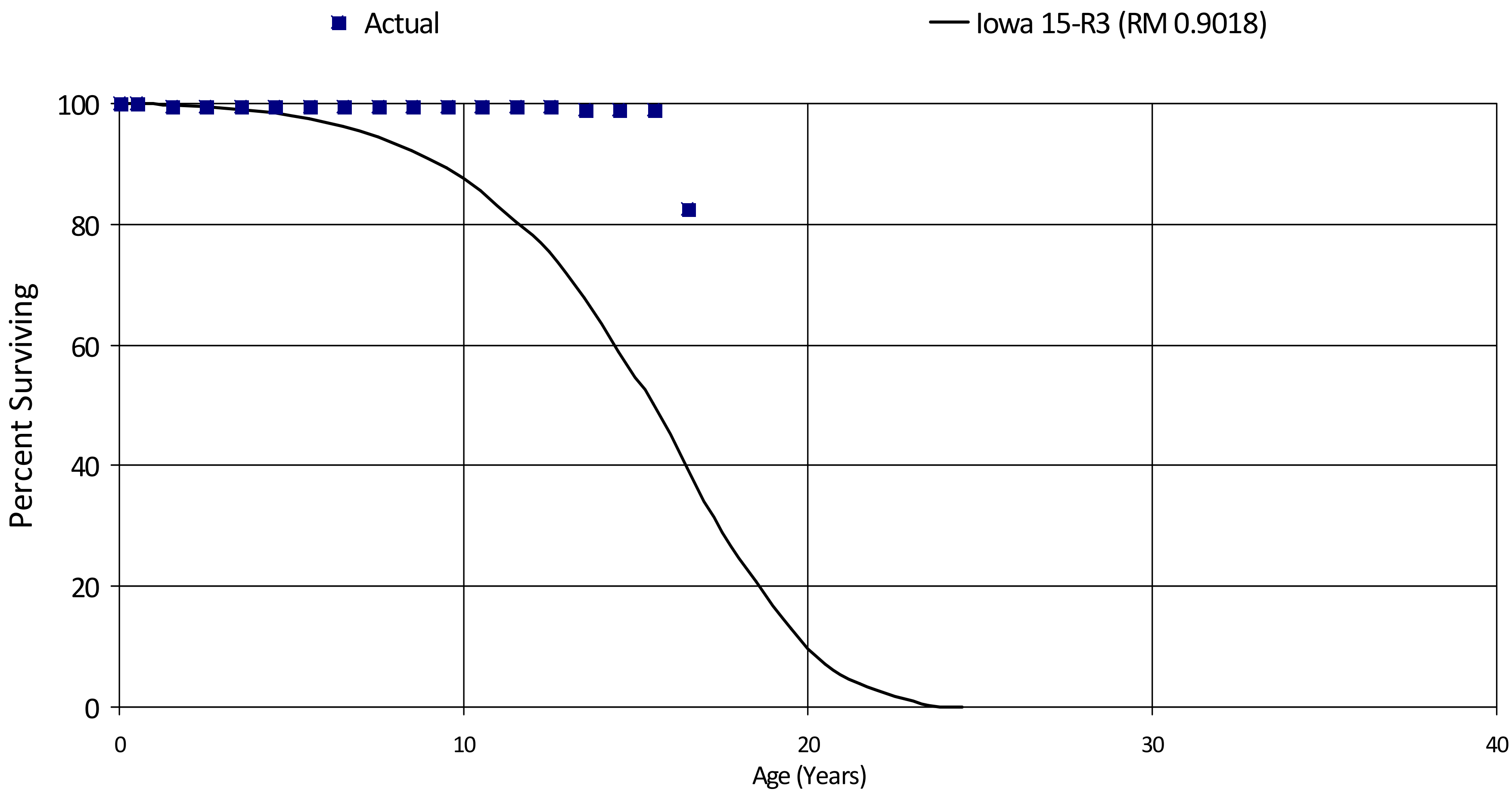
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	7,040,537	0	0.00000	1.00000	100.00
0.5	7,002,705	0	0.00000	1.00000	100.00
1.5	7,002,705	0	0.00000	1.00000	100.00
2.5	6,296,903	0	0.00000	1.00000	100.00
3.5	5,101,559	0	0.00000	1.00000	100.00
4.5	4,677,521	0	0.00000	1.00000	100.00
5.5	4,169,998	51,855	0.01244	0.98756	100.00
6.5	3,702,118	12,876	0.00348	0.99652	98.76
7.5	3,414,319	0	0.00000	1.00000	98.42
8.5	2,844,566	0	0.00000	1.00000	98.42
9.5	2,514,447	0	0.00000	1.00000	98.42
10.5	1,674,467	0	0.00000	1.00000	98.42
11.5	1,599,966	0	0.00000	1.00000	98.42
12.5	1,442,817	0	0.00000	1.00000	98.42
13.5	820,006	0	0.00000	1.00000	98.42
14.5	621,628	0	0.00000	1.00000	98.42
15.5	507,223	0	0.00000	1.00000	98.42
16.5	310,487	0	0.00000	1.00000	98.42
17.5	229,880	0	0.00000	1.00000	98.42
18.5	225,469	0	0.00000	1.00000	98.42
19.5	197,198	39,858	0.20212	0.79788	98.42
20.5	142,367	134,330	0.94355	0.05645	78.53
	Totals:	238,919			

BC Hydro Power Authority

Account 70101 - Hydrometeorological Equipment

Placement Band - 1998 - 2019   Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 70101 - Hydrometeorological Equipment

Placement Band - 1998 - 2019   Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

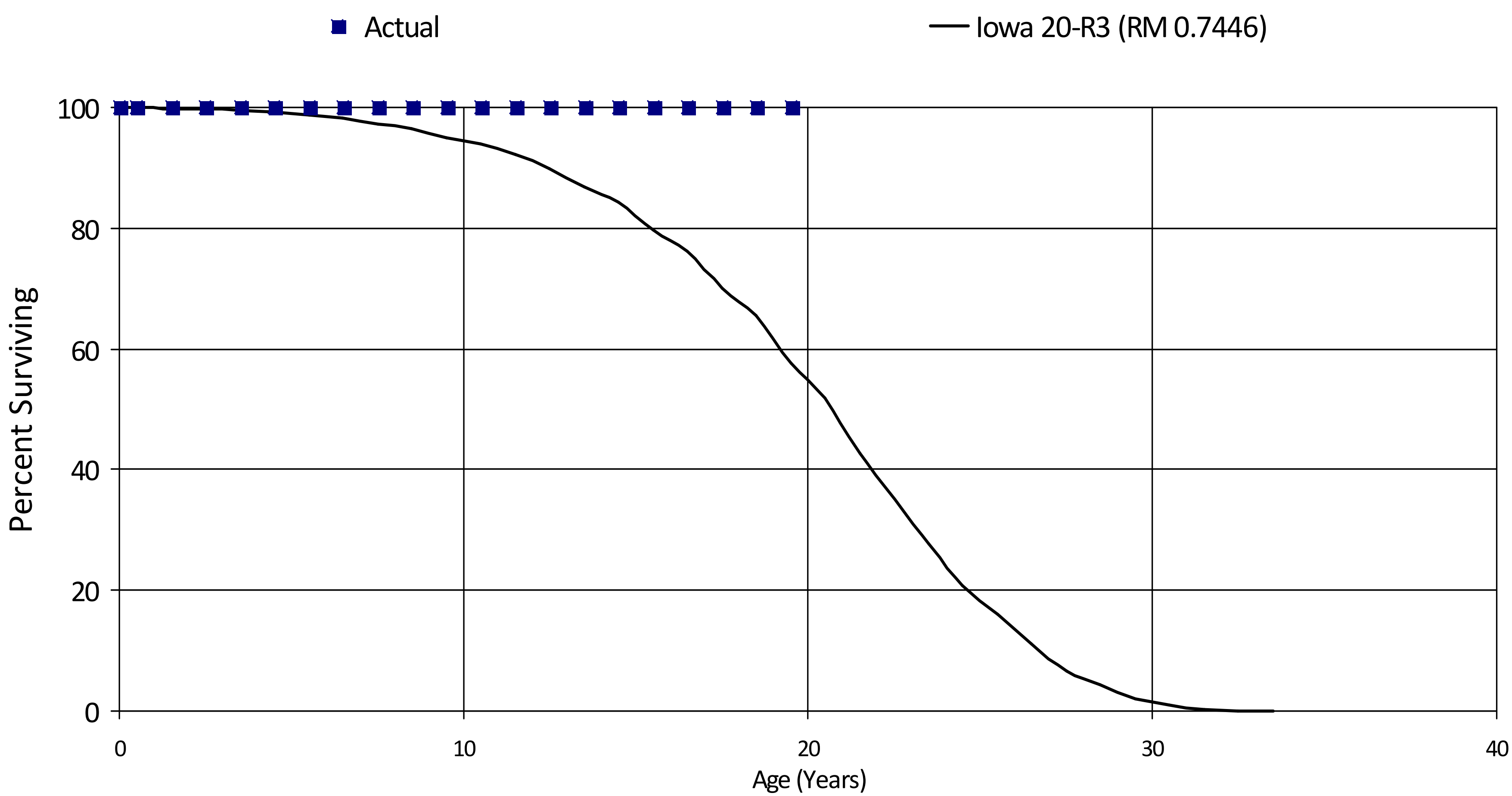
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	6,594,440	0	0.00000	1.00000	100.00
0.5	6,594,440	26,999	0.00409	0.99591	100.00
1.5	6,447,869	0	0.00000	1.00000	99.59
2.5	2,848,591	0	0.00000	1.00000	99.59
3.5	2,848,591	0	0.00000	1.00000	99.59
4.5	2,679,955	0	0.00000	1.00000	99.59
5.5	1,440,473	0	0.00000	1.00000	99.59
6.5	1,136,167	0	0.00000	1.00000	99.59
7.5	1,136,167	0	0.00000	1.00000	99.59
8.5	953,660	0	0.00000	1.00000	99.59
9.5	912,478	0	0.00000	1.00000	99.59
10.5	912,478	0	0.00000	1.00000	99.59
11.5	390,704	0	0.00000	1.00000	99.59
12.5	390,704	2,283	0.00584	0.99416	99.59
13.5	388,421	0	0.00000	1.00000	99.01
14.5	385,276	0	0.00000	1.00000	99.01
15.5	374,316	62,848	0.16790	0.83210	99.01
16.5	311,468	311,468	1.00000		82.39
	Totals:	403,598			

BC Hydro Power Authority

Account 70102 - Accelerometers

Placement Band - 1998 - 2016 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 70102 - Accelerometers

Placement Band - 1998 - 2016   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

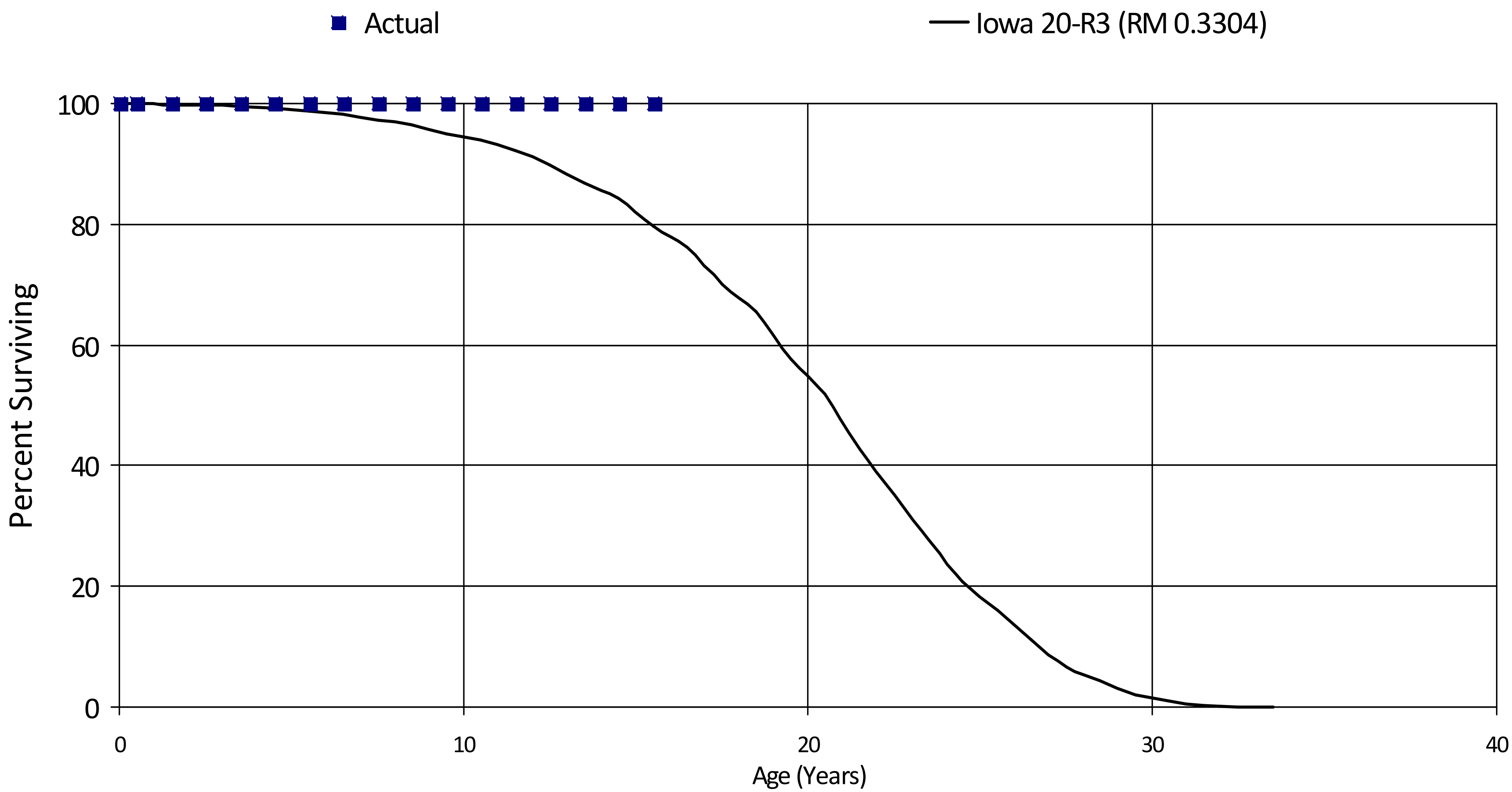
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,167,245	0	0.00000	1.00000	100.00
0.5	2,167,245	0	0.00000	1.00000	100.00
1.5	2,167,245	0	0.00000	1.00000	100.00
2.5	2,167,245	0	0.00000	1.00000	100.00
3.5	2,167,245	0	0.00000	1.00000	100.00
4.5	1,143,469	0	0.00000	1.00000	100.00
5.5	1,143,469	0	0.00000	1.00000	100.00
6.5	1,143,469	0	0.00000	1.00000	100.00
7.5	1,143,469	0	0.00000	1.00000	100.00
8.5	1,143,469	0	0.00000	1.00000	100.00
9.5	77,884	0	0.00000	1.00000	100.00
10.5	77,884	0	0.00000	1.00000	100.00
11.5	47,144	0	0.00000	1.00000	100.00
12.5	47,144	0	0.00000	1.00000	100.00
13.5	47,144	0	0.00000	1.00000	100.00
14.5	47,144	0	0.00000	1.00000	100.00
15.5	32,781	0	0.00000	1.00000	100.00
16.5	32,781	0	0.00000	1.00000	100.00
17.5	32,781	0	0.00000	1.00000	100.00
18.5	32,781	0	0.00000	1.00000	100.00
19.5	32,781	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 70103 - Seismic Monitoring Equipment

Placement Band - 1998 - 2016 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 70103 - Seismic Monitoring Equipment

Placement Band - 1998 - 2016   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

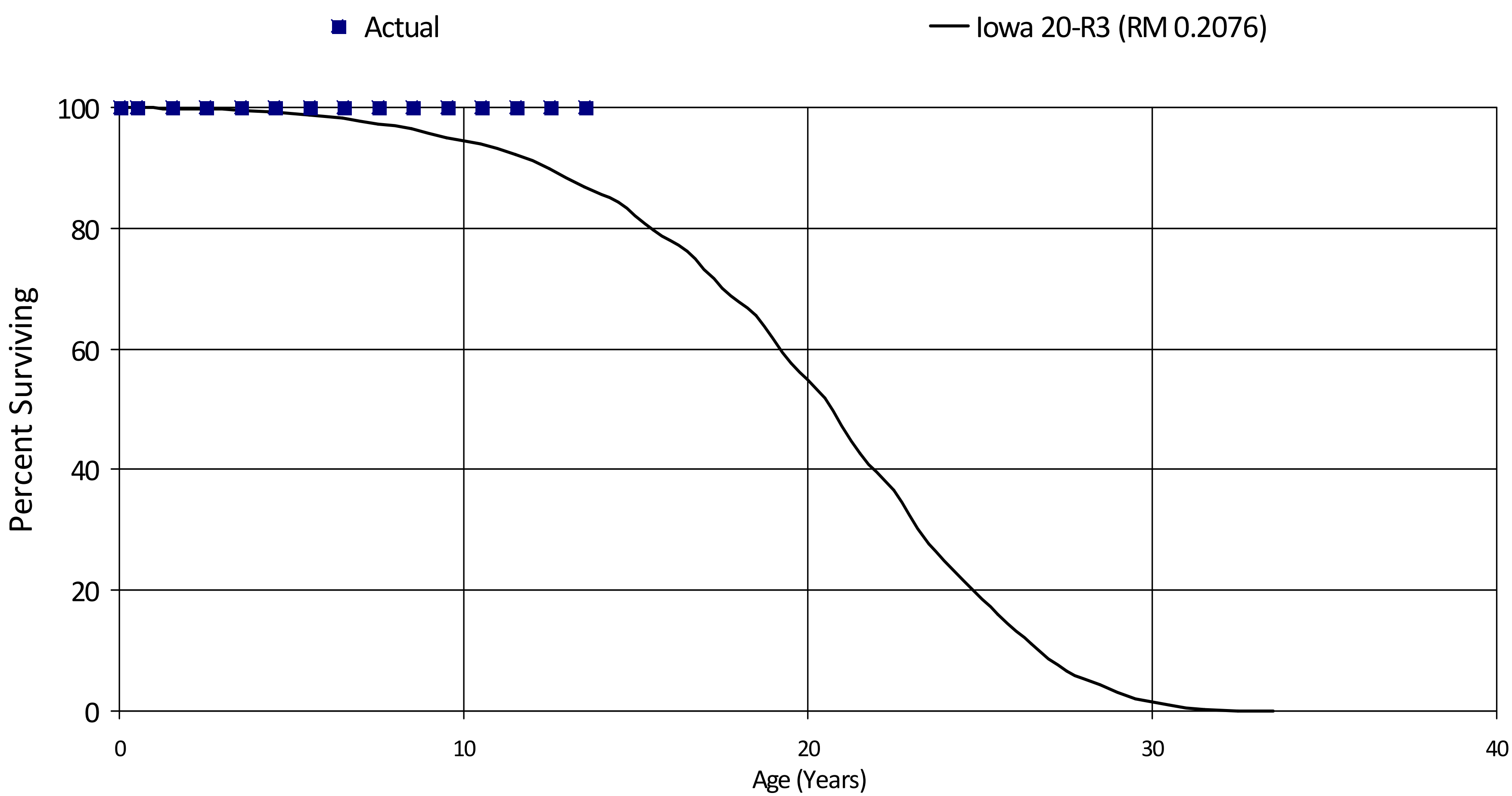
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	3,670,101	0	0.00000	1.00000	100.00
0.5	3,670,101	0	0.00000	1.00000	100.00
1.5	3,670,101	0	0.00000	1.00000	100.00
2.5	3,670,101	0	0.00000	1.00000	100.00
3.5	3,670,101	0	0.00000	1.00000	100.00
4.5	3,518,197	0	0.00000	1.00000	100.00
5.5	3,518,197	0	0.00000	1.00000	100.00
6.5	3,518,197	0	0.00000	1.00000	100.00
7.5	3,518,197	0	0.00000	1.00000	100.00
8.5	3,518,197	0	0.00000	1.00000	100.00
9.5	3,518,197	0	0.00000	1.00000	100.00
10.5	1,689,261	0	0.00000	1.00000	100.00
11.5	941,681	0	0.00000	1.00000	100.00
12.5	941,681	0	0.00000	1.00000	100.00
13.5	758,760	0	0.00000	1.00000	100.00
14.5	388,439	0	0.00000	1.00000	100.00
15.5	381,424	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 70104 - Instrumentation - Digital

Placement Band - 1996 - 2020 Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 70104 - Instrumentation - Digital

Placement Band - 1996 - 2020 Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

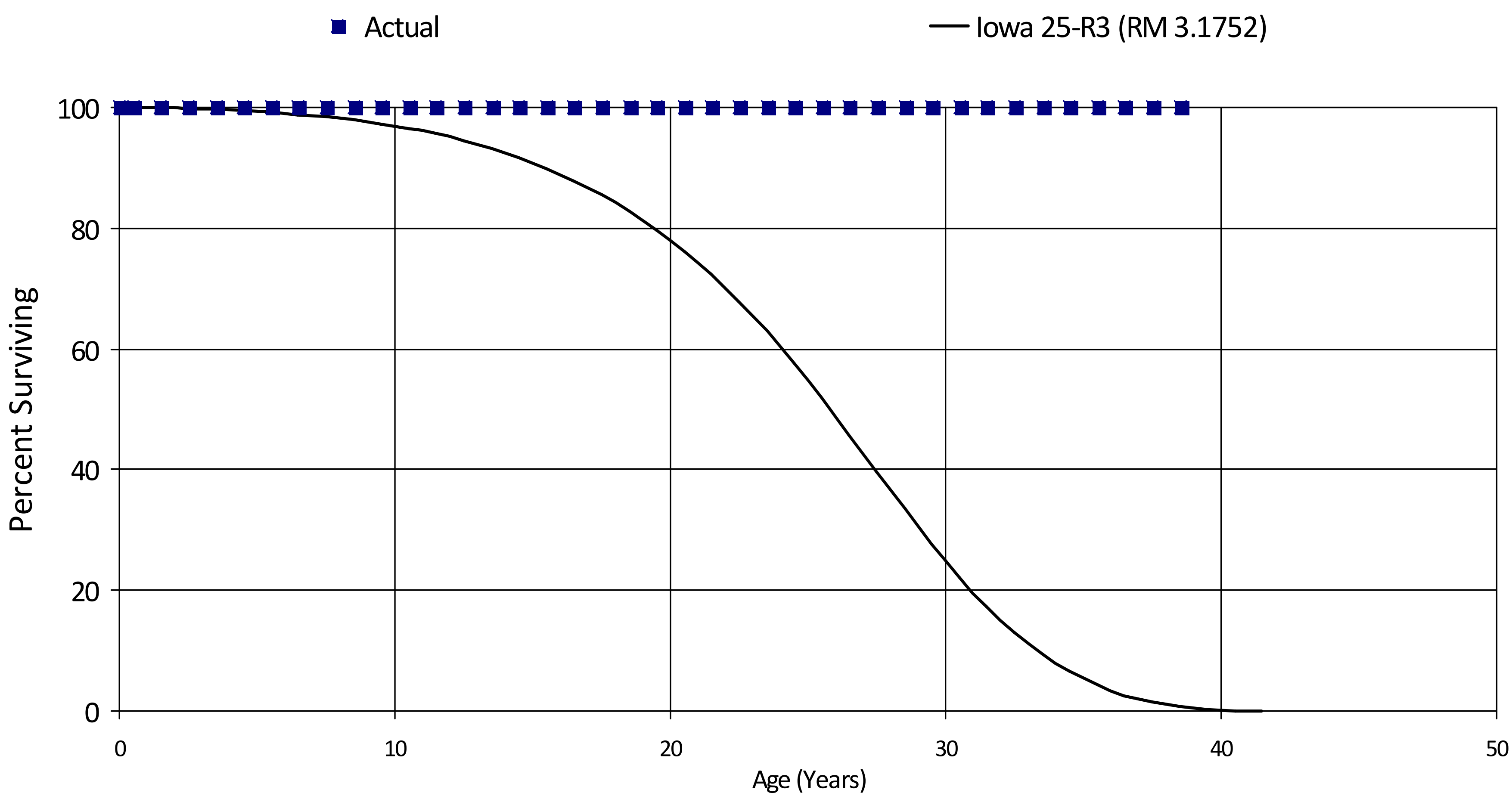
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	34,279,554	0	0.00000	1.00000	100.00
0.5	33,097,559	0	0.00000	1.00000	100.00
1.5	30,663,535	0	0.00000	1.00000	100.00
2.5	29,666,663	0	0.00000	1.00000	100.00
3.5	29,521,351	0	0.00000	1.00000	100.00
4.5	22,661,307	0	0.00000	1.00000	100.00
5.5	20,201,166	0	0.00000	1.00000	100.00
6.5	15,539,580	0	0.00000	1.00000	100.00
7.5	8,544,374	0	0.00000	1.00000	100.00
8.5	580,160	0	0.00000	1.00000	100.00
9.5	580,160	0	0.00000	1.00000	100.00
10.5	572,173	0	0.00000	1.00000	100.00
11.5	425,651	0	0.00000	1.00000	100.00
12.5	370,356	0	0.00000	1.00000	100.00
13.5	354,366	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 70105 - Instrumentation - Analogue

Placement Band - 1972 - 2019 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 70105 - Instrumentation - Analogue

Placement Band - 1972 - 2019   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,747,871	0	0.00000	1.00000	100.00
0.5	1,747,871	0	0.00000	1.00000	100.00
1.5	1,081,220	0	0.00000	1.00000	100.00
2.5	1,081,220	0	0.00000	1.00000	100.00
3.5	1,081,220	0	0.00000	1.00000	100.00
4.5	1,031,725	0	0.00000	1.00000	100.00
5.5	911,671	0	0.00000	1.00000	100.00
6.5	911,671	0	0.00000	1.00000	100.00
7.5	911,671	0	0.00000	1.00000	100.00
8.5	911,671	0	0.00000	1.00000	100.00
9.5	911,671	0	0.00000	1.00000	100.00
10.5	911,671	0	0.00000	1.00000	100.00
11.5	845,069	0	0.00000	1.00000	100.00
12.5	829,803	0	0.00000	1.00000	100.00
13.5	823,825	0	0.00000	1.00000	100.00
14.5	628,010	769	0.00122	0.99878	100.00
15.5	565,937	0	0.00000	1.00000	99.88
16.5	388,697	0	0.00000	1.00000	99.88
17.5	353,315	0	0.00000	1.00000	99.88
18.5	353,315	0	0.00000	1.00000	99.88
19.5	353,315	0	0.00000	1.00000	99.88
20.5	179,280	0	0.00000	1.00000	99.88
21.5	132,900	0	0.00000	1.00000	99.88
22.5	67,706	0	0.00000	1.00000	99.88
23.5	62,927	0	0.00000	1.00000	99.88
24.5	62,433	0	0.00000	1.00000	99.88
25.5	62,433	0	0.00000	1.00000	99.88
26.5	62,095	0	0.00000	1.00000	99.88

BC Hydro Power Authority

Account 70105 - Instrumentation - Analogue

Placement Band - 1972 - 2019 Experience Band - 2013 - 2020

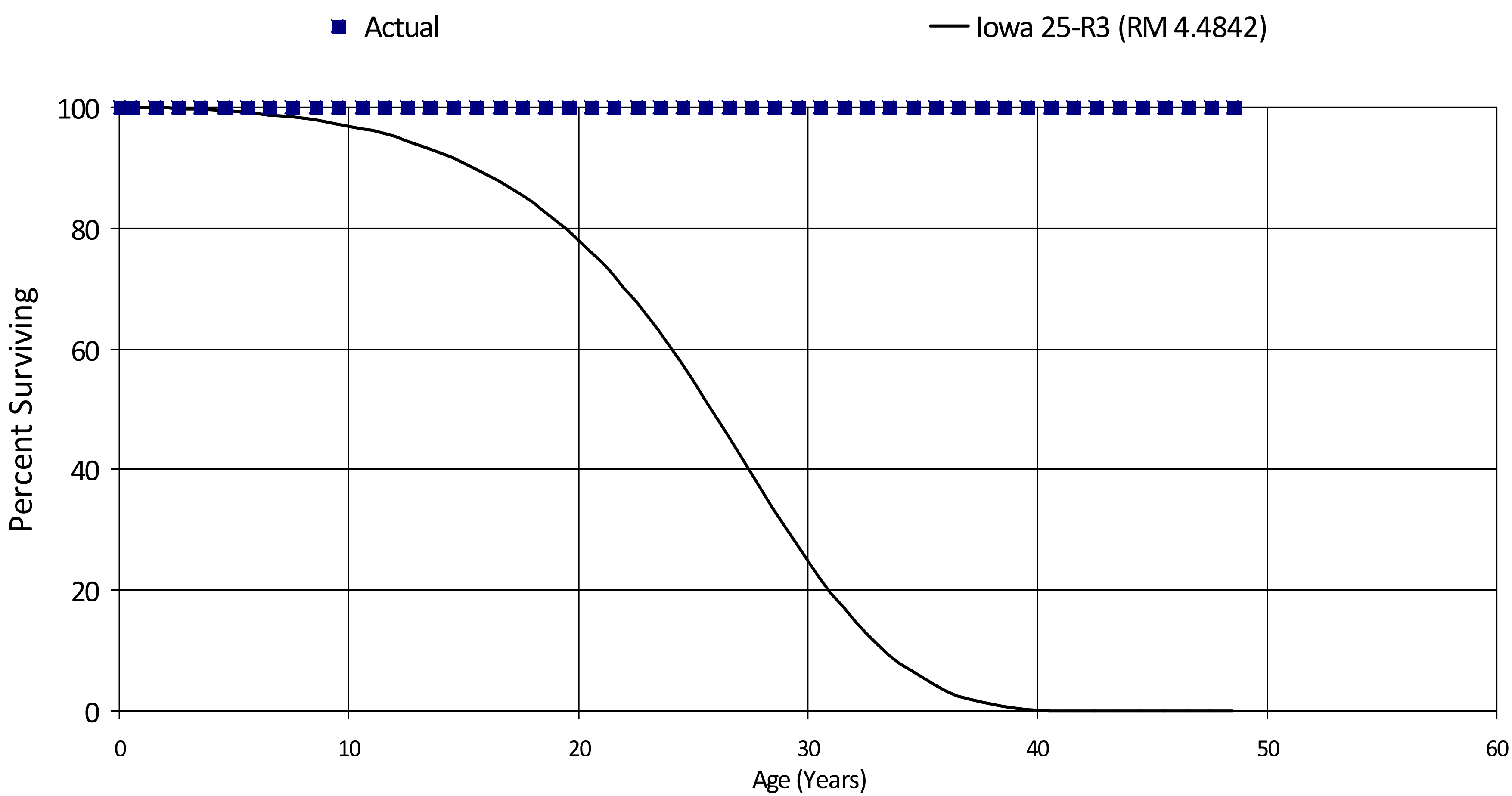
27.5	56,827	0	0.00000	1.00000	99.88
28.5	56,312	0	0.00000	1.00000	99.88
29.5	56,312	0	0.00000	1.00000	99.88
30.5	50,980	0	0.00000	1.00000	99.88
31.5	50,980	0	0.00000	1.00000	99.88
32.5	50,980	0	0.00000	1.00000	99.88
33.5	50,980	0	0.00000	1.00000	99.88
34.5	50,980	0	0.00000	1.00000	99.88
35.5	21,530	0	0.00000	1.00000	99.88
36.5	21,530	0	0.00000	1.00000	99.88
37.5	21,530	0	0.00000	1.00000	99.88
38.5	21,138	0	0.00000	1.00000	99.88
	Totals:	769			

BC Hydro Power Authority

Account 73001 - Cooling System, Air

Placement Band - 1959 - 2018 Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 73001 - Cooling System, Air

Placement Band - 1959 - 2018   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	23,053,213	0	0.00000	1.00000	100.00
0.5	23,053,213	0	0.00000	1.00000	100.00
1.5	23,053,213	0	0.00000	1.00000	100.00
2.5	23,026,760	0	0.00000	1.00000	100.00
3.5	23,026,760	0	0.00000	1.00000	100.00
4.5	23,026,760	0	0.00000	1.00000	100.00
5.5	22,468,066	0	0.00000	1.00000	100.00
6.5	22,468,066	0	0.00000	1.00000	100.00
7.5	22,457,479	0	0.00000	1.00000	100.00
8.5	6,162,845	0	0.00000	1.00000	100.00
9.5	6,162,845	0	0.00000	1.00000	100.00
10.5	5,866,513	0	0.00000	1.00000	100.00
11.5	5,836,435	0	0.00000	1.00000	100.00
12.5	5,665,727	0	0.00000	1.00000	100.00
13.5	5,651,493	0	0.00000	1.00000	100.00
14.5	3,699,021	0	0.00000	1.00000	100.00
15.5	3,699,021	0	0.00000	1.00000	100.00
16.5	3,679,166	0	0.00000	1.00000	100.00
17.5	3,679,166	0	0.00000	1.00000	100.00
18.5	3,569,650	0	0.00000	1.00000	100.00
19.5	3,553,858	0	0.00000	1.00000	100.00
20.5	3,553,858	0	0.00000	1.00000	100.00
21.5	3,553,858	0	0.00000	1.00000	100.00
22.5	3,531,459	0	0.00000	1.00000	100.00
23.5	3,531,459	0	0.00000	1.00000	100.00
24.5	3,470,922	0	0.00000	1.00000	100.00
25.5	3,470,922	0	0.00000	1.00000	100.00
26.5	3,465,694	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 73001 - Cooling System, Air

Placement Band - 1959 - 2018 Experience Band - 2011 - 2020

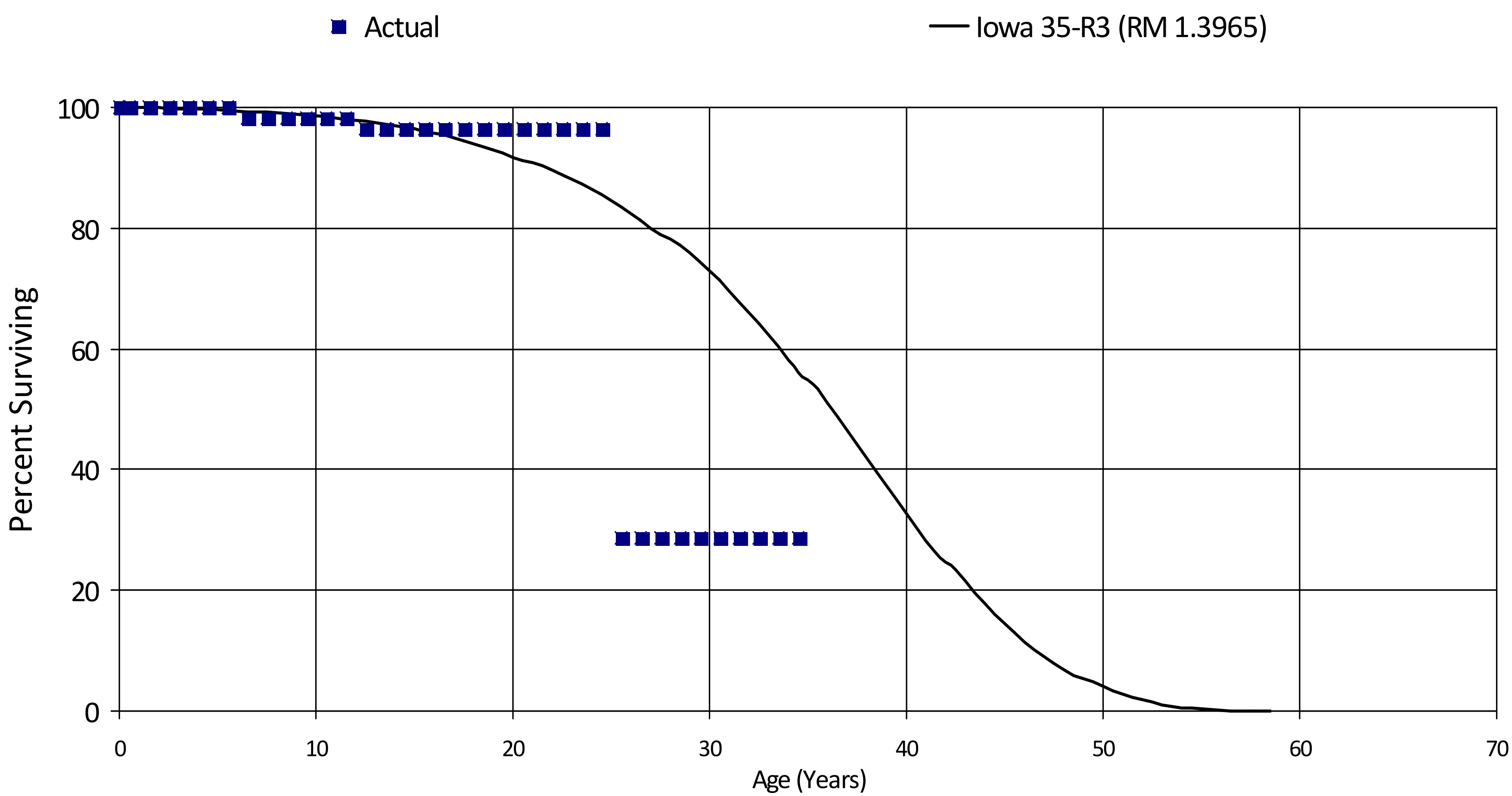
27.5	3,454,951	0	0.00000	1.00000	100.00
28.5	3,454,951	0	0.00000	1.00000	100.00
29.5	3,454,951	0	0.00000	1.00000	100.00
30.5	3,454,951	0	0.00000	1.00000	100.00
31.5	3,454,951	0	0.00000	1.00000	100.00
32.5	3,454,951	0	0.00000	1.00000	100.00
33.5	3,454,951	0	0.00000	1.00000	100.00
34.5	3,454,951	0	0.00000	1.00000	100.00
35.5	3,454,951	0	0.00000	1.00000	100.00
36.5	3,454,951	0	0.00000	1.00000	100.00
37.5	3,454,951	0	0.00000	1.00000	100.00
38.5	3,454,951	0	0.00000	1.00000	100.00
39.5	3,454,951	0	0.00000	1.00000	100.00
40.5	3,454,951	0	0.00000	1.00000	100.00
41.5	3,454,951	0	0.00000	1.00000	100.00
42.5	3,454,951	0	0.00000	1.00000	100.00
43.5	3,454,951	0	0.00000	1.00000	100.00
44.5	3,454,951	0	0.00000	1.00000	100.00
45.5	3,454,951	0	0.00000	1.00000	100.00
46.5	3,454,951	0	0.00000	1.00000	100.00
47.5	3,454,951	0	0.00000	1.00000	100.00
48.5	3,454,951	3,454,951	1.00000		100.00
	Totals:	3,454,951			

BC Hydro Power Authority

Account 74001 - Motor - Generator Sets

Placement Band - 1955 - 2020 Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 74001 - Motor - Generator Sets

Placement Band - 1955 - 2020 Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	23,775,114	0	0.00000	1.00000	100.00
0.5	23,742,035	0	0.00000	1.00000	100.00
1.5	23,472,005	0	0.00000	1.00000	100.00
2.5	22,570,511	0	0.00000	1.00000	100.00
3.5	22,008,775	0	0.00000	1.00000	100.00
4.5	19,230,051	0	0.00000	1.00000	100.00
5.5	17,868,532	303,787	0.01700	0.98300	100.00
6.5	16,105,265	0	0.00000	1.00000	98.30
7.5	15,283,056	0	0.00000	1.00000	98.30
8.5	9,756,188	0	0.00000	1.00000	98.30
9.5	8,480,894	0	0.00000	1.00000	98.30
10.5	4,865,972	0	0.00000	1.00000	98.30
11.5	2,671,393	52,428	0.01963	0.98037	98.30
12.5	2,395,100	0	0.00000	1.00000	96.37
13.5	2,143,904	0	0.00000	1.00000	96.37
14.5	2,143,904	0	0.00000	1.00000	96.37
15.5	2,126,938	0	0.00000	1.00000	96.37
16.5	1,987,371	0	0.00000	1.00000	96.37
17.5	1,987,371	0	0.00000	1.00000	96.37
18.5	1,987,371	0	0.00000	1.00000	96.37
19.5	1,987,371	0	0.00000	1.00000	96.37
20.5	1,987,371	0	0.00000	1.00000	96.37
21.5	1,987,371	0	0.00000	1.00000	96.37
22.5	1,987,371	0	0.00000	1.00000	96.37
23.5	1,987,371	0	0.00000	1.00000	96.37
24.5	1,987,371	1,397,393	0.70314	0.29686	96.37
25.5	589,979	0	0.00000	1.00000	28.61
26.5	300,964	0	0.00000	1.00000	28.61

BC Hydro Power Authority

Account 74001 - Motor - Generator Sets

Placement Band - 1955 - 2020   Experience Band - 2011 - 2020

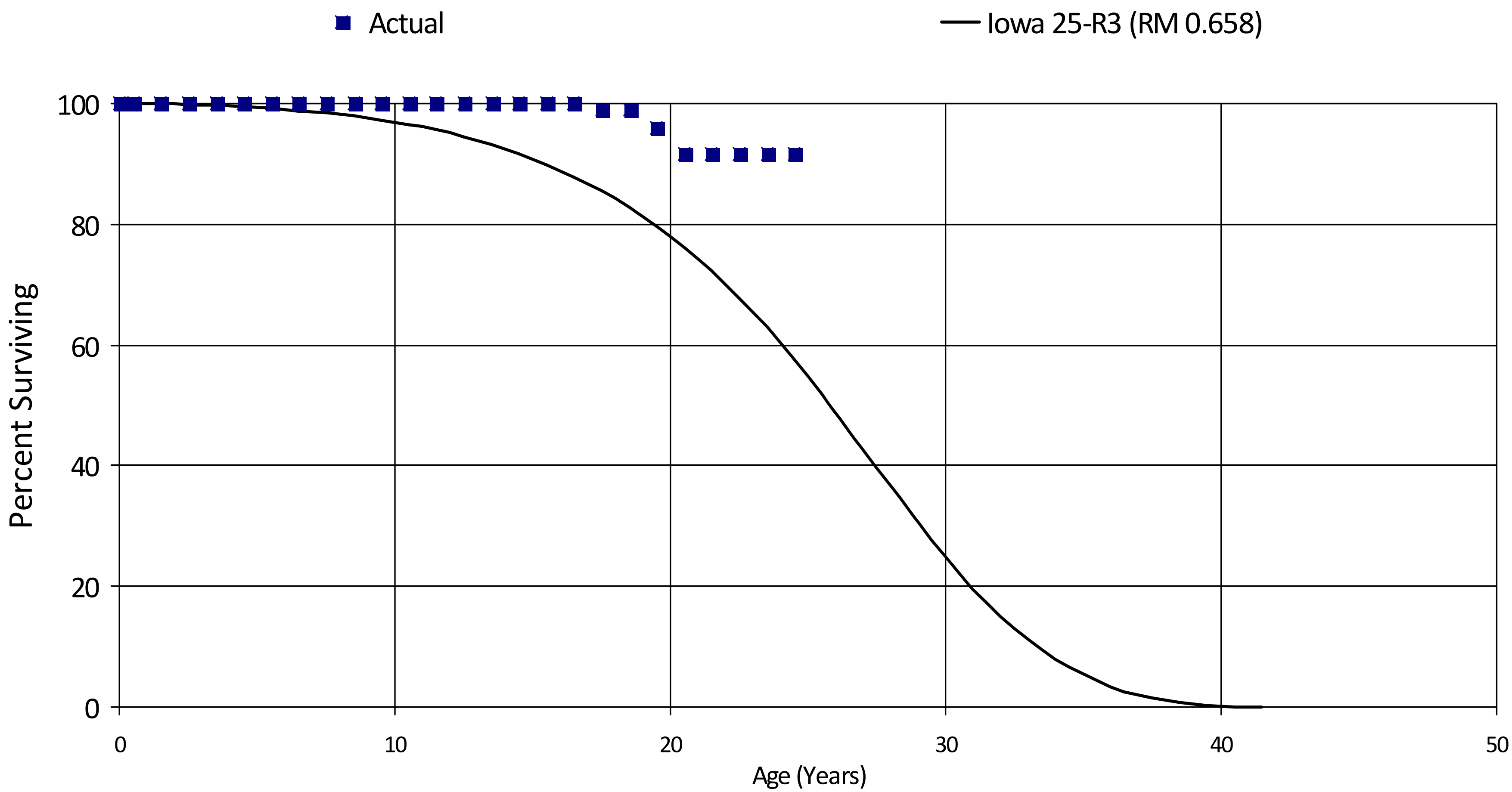
27.5	295,631	0	0.00000	1.00000	28.61
28.5	295,631	0	0.00000	1.00000	28.61
29.5	295,631	0	0.00000	1.00000	28.61
30.5	282,986	0	0.00000	1.00000	28.61
31.5	282,986	0	0.00000	1.00000	28.61
32.5	256,542	0	0.00000	1.00000	28.61
33.5	256,542	0	0.00000	1.00000	28.61
34.5	256,542	0	0.00000	1.00000	28.61
	Totals:	1,753,608			

BC Hydro Power Authority

Account 75101 - Drier, Air

Placement Band - 1993 - 2019   Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 75101 - Drier, Air

Placement Band - 1993 - 2019   Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

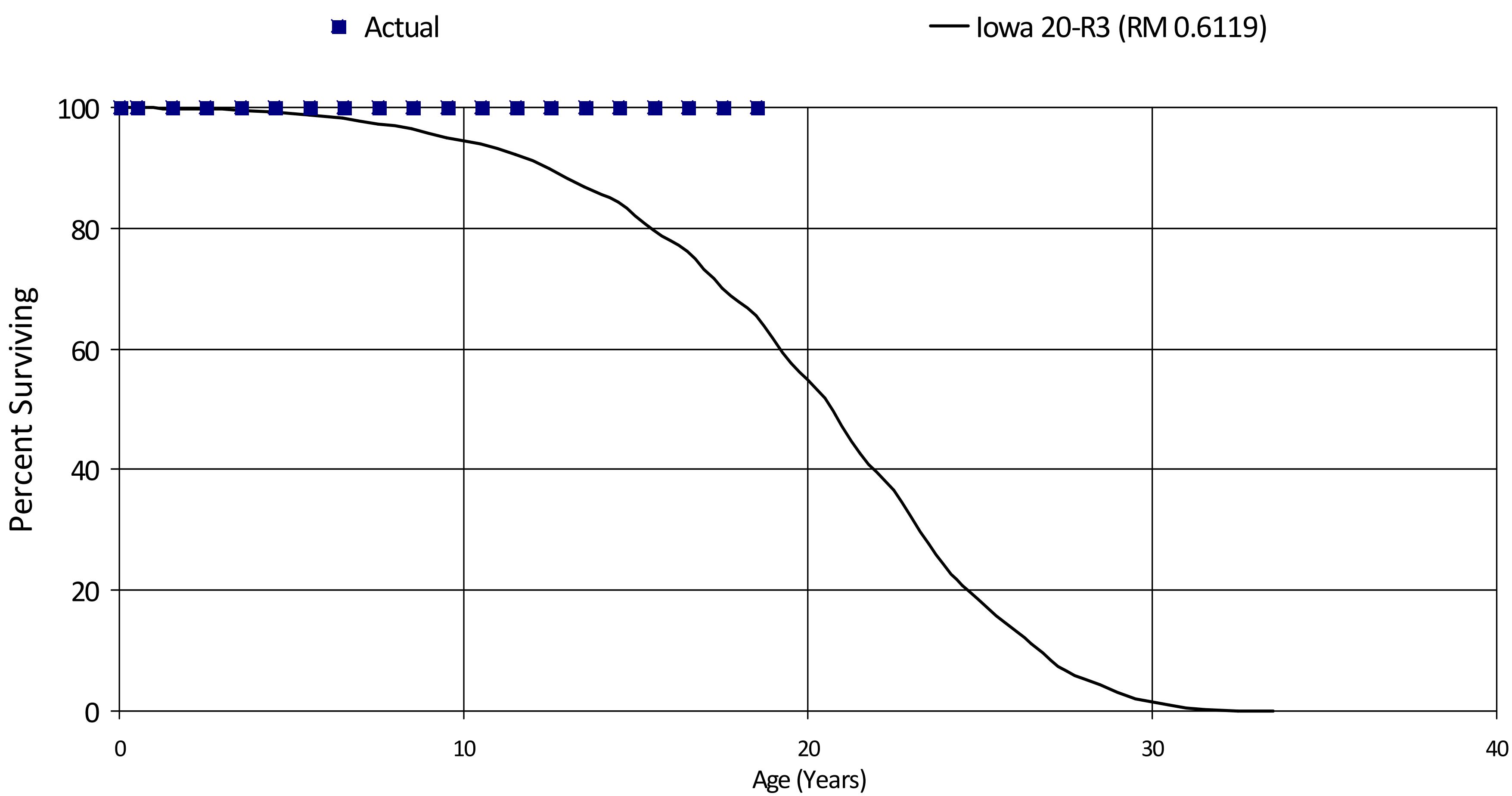
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	828,023	0	0.00000	1.00000	100.00
0.5	828,023	0	0.00000	1.00000	100.00
1.5	808,476	0	0.00000	1.00000	100.00
2.5	808,476	0	0.00000	1.00000	100.00
3.5	808,476	0	0.00000	1.00000	100.00
4.5	808,476	0	0.00000	1.00000	100.00
5.5	808,476	0	0.00000	1.00000	100.00
6.5	808,476	0	0.00000	1.00000	100.00
7.5	750,222	0	0.00000	1.00000	100.00
8.5	750,222	0	0.00000	1.00000	100.00
9.5	750,222	0	0.00000	1.00000	100.00
10.5	718,292	0	0.00000	1.00000	100.00
11.5	718,292	0	0.00000	1.00000	100.00
12.5	718,292	0	0.00000	1.00000	100.00
13.5	671,656	0	0.00000	1.00000	100.00
14.5	659,256	0	0.00000	1.00000	100.00
15.5	659,256	0	0.00000	1.00000	100.00
16.5	547,387	5,708	0.01043	0.98957	100.00
17.5	310,822	0	0.00000	1.00000	98.96
18.5	241,310	7,171	0.02972	0.97028	98.96
19.5	234,139	10,549	0.04505	0.95495	96.02
20.5	223,591	0	0.00000	1.00000	91.69
21.5	140,450	0	0.00000	1.00000	91.69
22.5	69,556	0	0.00000	1.00000	91.69
23.5	49,025	0	0.00000	1.00000	91.69
24.5	46,117	0	0.00000	1.00000	91.69
	Totals:	23,428			

BC Hydro Power Authority

Account 75102 - Piping / Valving, Steel

Placement Band - 1995 - 2016   Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 75102 - Piping / Valving, Steel

Placement Band - 1995 - 2016 Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

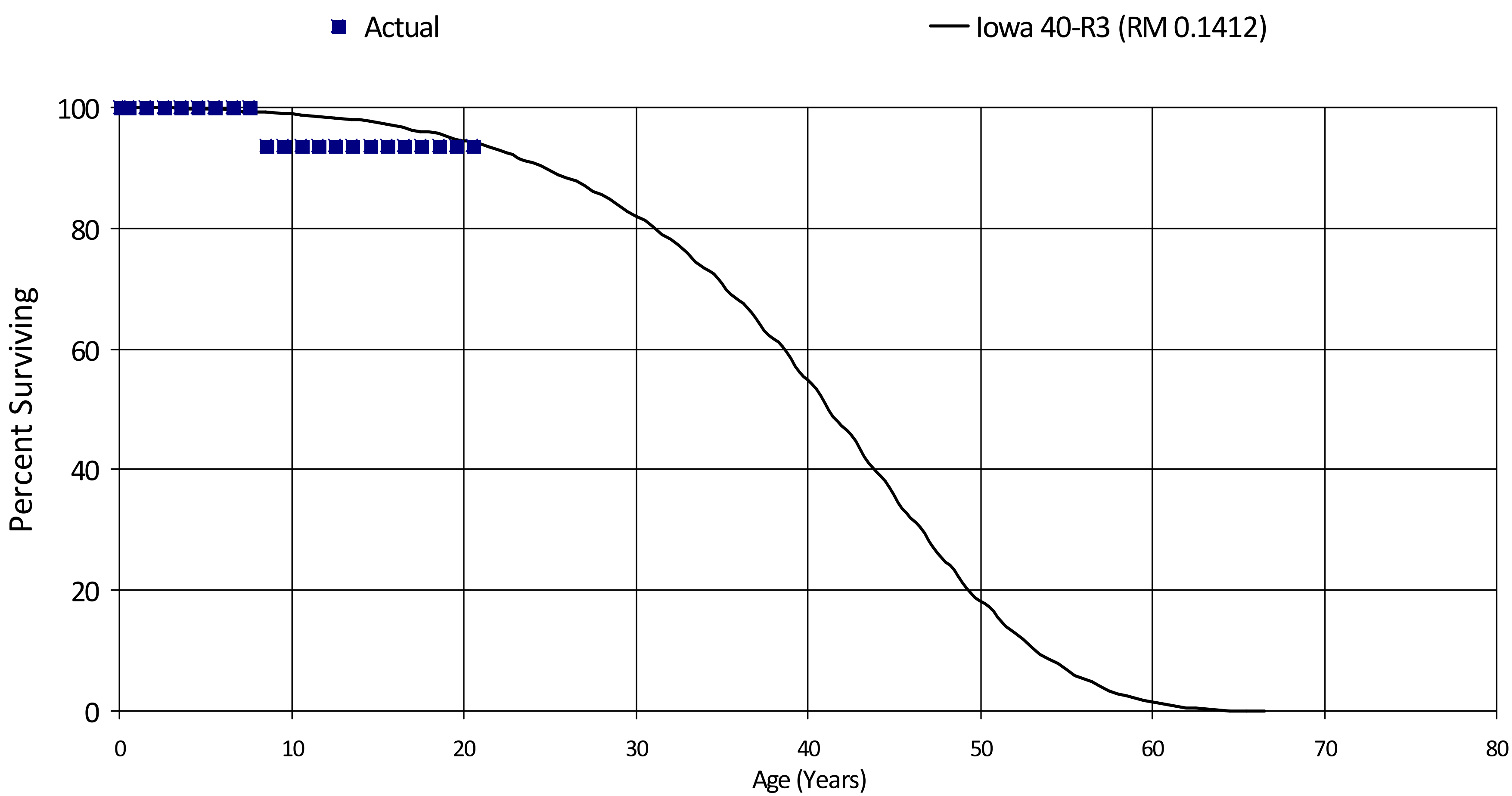
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	549,739	0	0.00000	1.00000	100.00
0.5	549,739	0	0.00000	1.00000	100.00
1.5	549,739	0	0.00000	1.00000	100.00
2.5	549,739	0	0.00000	1.00000	100.00
3.5	549,739	0	0.00000	1.00000	100.00
4.5	176,859	0	0.00000	1.00000	100.00
5.5	176,859	0	0.00000	1.00000	100.00
6.5	176,859	0	0.00000	1.00000	100.00
7.5	136,698	0	0.00000	1.00000	100.00
8.5	136,698	0	0.00000	1.00000	100.00
9.5	136,698	0	0.00000	1.00000	100.00
10.5	136,698	0	0.00000	1.00000	100.00
11.5	136,698	0	0.00000	1.00000	100.00
12.5	136,698	0	0.00000	1.00000	100.00
13.5	136,698	0	0.00000	1.00000	100.00
14.5	136,698	0	0.00000	1.00000	100.00
15.5	136,698	0	0.00000	1.00000	100.00
16.5	22,749	0	0.00000	1.00000	100.00
17.5	19,389	0	0.00000	1.00000	100.00
18.5	9,070	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 75103 - Piping, Stainless Steel

Placement Band - 1999 - 2019   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 75103 - Piping, Stainless Steel

Placement Band - 1999 - 2019 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

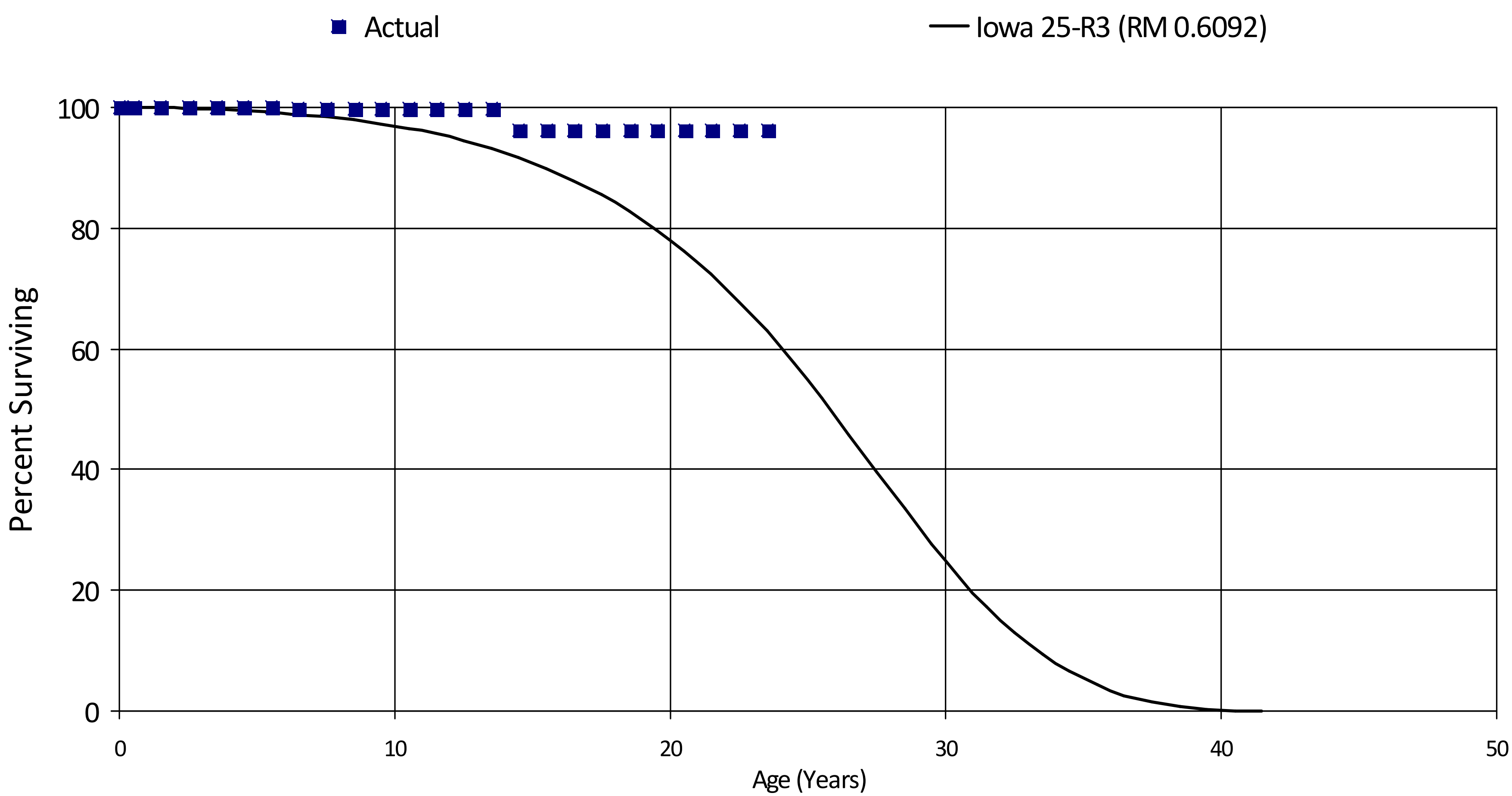
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,040,222	0	0.00000	1.00000	100.00
0.5	2,040,222	0	0.00000	1.00000	100.00
1.5	2,020,674	0	0.00000	1.00000	100.00
2.5	1,743,045	0	0.00000	1.00000	100.00
3.5	1,743,045	0	0.00000	1.00000	100.00
4.5	1,743,045	0	0.00000	1.00000	100.00
5.5	1,743,045	0	0.00000	1.00000	100.00
6.5	1,743,045	0	0.00000	1.00000	100.00
7.5	1,647,057	104,745	0.06360	0.93640	100.00
8.5	1,332,635	0	0.00000	1.00000	93.64
9.5	1,332,635	0	0.00000	1.00000	93.64
10.5	1,332,635	0	0.00000	1.00000	93.64
11.5	1,332,635	0	0.00000	1.00000	93.64
12.5	1,332,635	0	0.00000	1.00000	93.64
13.5	1,332,635	0	0.00000	1.00000	93.64
14.5	1,308,323	0	0.00000	1.00000	93.64
15.5	1,308,323	0	0.00000	1.00000	93.64
16.5	1,104,812	0	0.00000	1.00000	93.64
17.5	404,331	0	0.00000	1.00000	93.64
18.5	404,331	0	0.00000	1.00000	93.64
19.5	404,331	0	0.00000	1.00000	93.64
20.5	404,331	0	0.00000	1.00000	93.64
	Totals:	104,745			

BC Hydro Power Authority

Account 75104 - Compressor, Air

Placement Band - 1939 - 2019   Experience Band - 2015 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 75104 - Compressor, Air

Placement Band - 1939 - 2019   Experience Band - 2015 - 2020

RETIREMENT RATE ANALYSIS

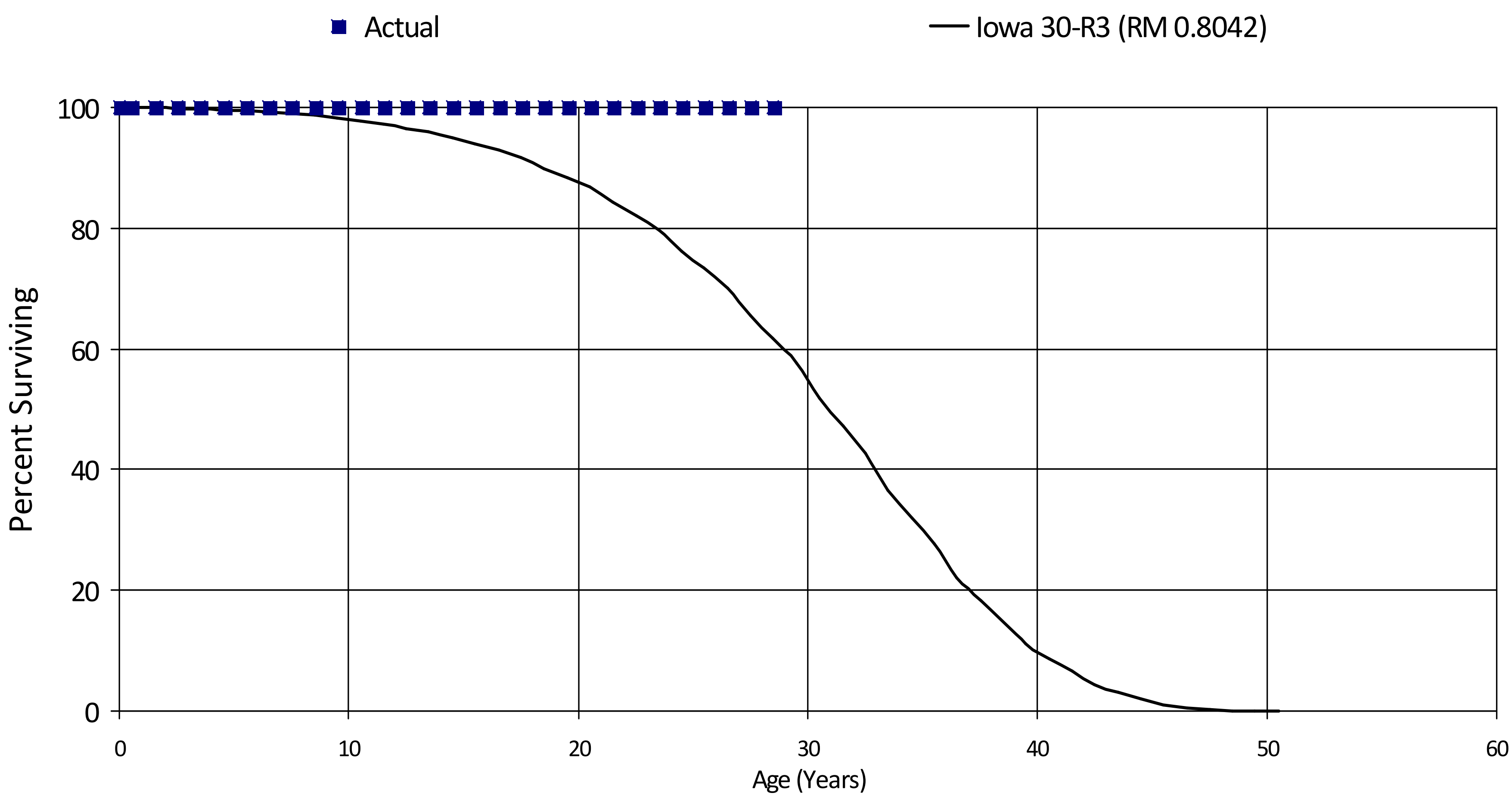
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	12,132,595	0	0.00000	1.00000	100.00
0.5	12,132,595	0	0.00000	1.00000	100.00
1.5	9,181,636	0	0.00000	1.00000	100.00
2.5	9,012,864	0	0.00000	1.00000	100.00
3.5	8,919,986	0	0.00000	1.00000	100.00
4.5	7,333,934	0	0.00000	1.00000	100.00
5.5	7,262,366	15,525	0.00214	0.99786	100.00
6.5	7,246,841	0	0.00000	1.00000	99.79
7.5	5,444,275	0	0.00000	1.00000	99.79
8.5	4,194,757	5,090	0.00121	0.99879	99.79
9.5	4,189,667	0	0.00000	1.00000	99.67
10.5	2,361,389	0	0.00000	1.00000	99.67
11.5	2,317,915	0	0.00000	1.00000	99.67
12.5	2,317,915	0	0.00000	1.00000	99.67
13.5	1,767,326	60,320	0.03413	0.96587	99.67
14.5	1,656,525	0	0.00000	1.00000	96.27
15.5	1,635,879	0	0.00000	1.00000	96.27
16.5	938,521	0	0.00000	1.00000	96.27
17.5	697,302	0	0.00000	1.00000	96.27
18.5	578,374	0	0.00000	1.00000	96.27
19.5	552,495	0	0.00000	1.00000	96.27
20.5	517,941	0	0.00000	1.00000	96.27
21.5	335,939	0	0.00000	1.00000	96.27
22.5	334,772	0	0.00000	1.00000	96.27
23.5	160,080	21,214	0.13252	0.86748	96.27
	Totals:	102,149			

BC Hydro Power Authority

Account 75201 - Tanks, Steel, Air / Fuel

Placement Band - 1982 - 2020 Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 75201 - Tanks, Steel, Air / Fuel

Placement Band - 1982 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	7,368,386	0	0.00000	1.00000	100.00
0.5	7,311,011	0	0.00000	1.00000	100.00
1.5	7,301,237	0	0.00000	1.00000	100.00
2.5	7,132,513	0	0.00000	1.00000	100.00
3.5	7,114,950	0	0.00000	1.00000	100.00
4.5	6,680,705	0	0.00000	1.00000	100.00
5.5	6,669,815	0	0.00000	1.00000	100.00
6.5	6,598,316	0	0.00000	1.00000	100.00
7.5	6,237,608	0	0.00000	1.00000	100.00
8.5	6,207,059	0	0.00000	1.00000	100.00
9.5	3,902,632	0	0.00000	1.00000	100.00
10.5	3,902,632	0	0.00000	1.00000	100.00
11.5	3,509,468	0	0.00000	1.00000	100.00
12.5	3,391,530	0	0.00000	1.00000	100.00
13.5	3,322,997	0	0.00000	1.00000	100.00
14.5	2,838,820	0	0.00000	1.00000	100.00
15.5	2,793,124	0	0.00000	1.00000	100.00
16.5	2,762,837	0	0.00000	1.00000	100.00
17.5	1,799,909	0	0.00000	1.00000	100.00
18.5	1,557,089	0	0.00000	1.00000	100.00
19.5	1,476,484	0	0.00000	1.00000	100.00
20.5	1,035,051	0	0.00000	1.00000	100.00
21.5	820,161	0	0.00000	1.00000	100.00
22.5	415,896	0	0.00000	1.00000	100.00
23.5	385,094	0	0.00000	1.00000	100.00
24.5	202,692	0	0.00000	1.00000	100.00
25.5	140,110	0	0.00000	1.00000	100.00
26.5	106,415	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 75201 - Tanks, Steel, Air / Fuel

Placement Band - 1982 - 2020 Experience Band - 2013 - 2020

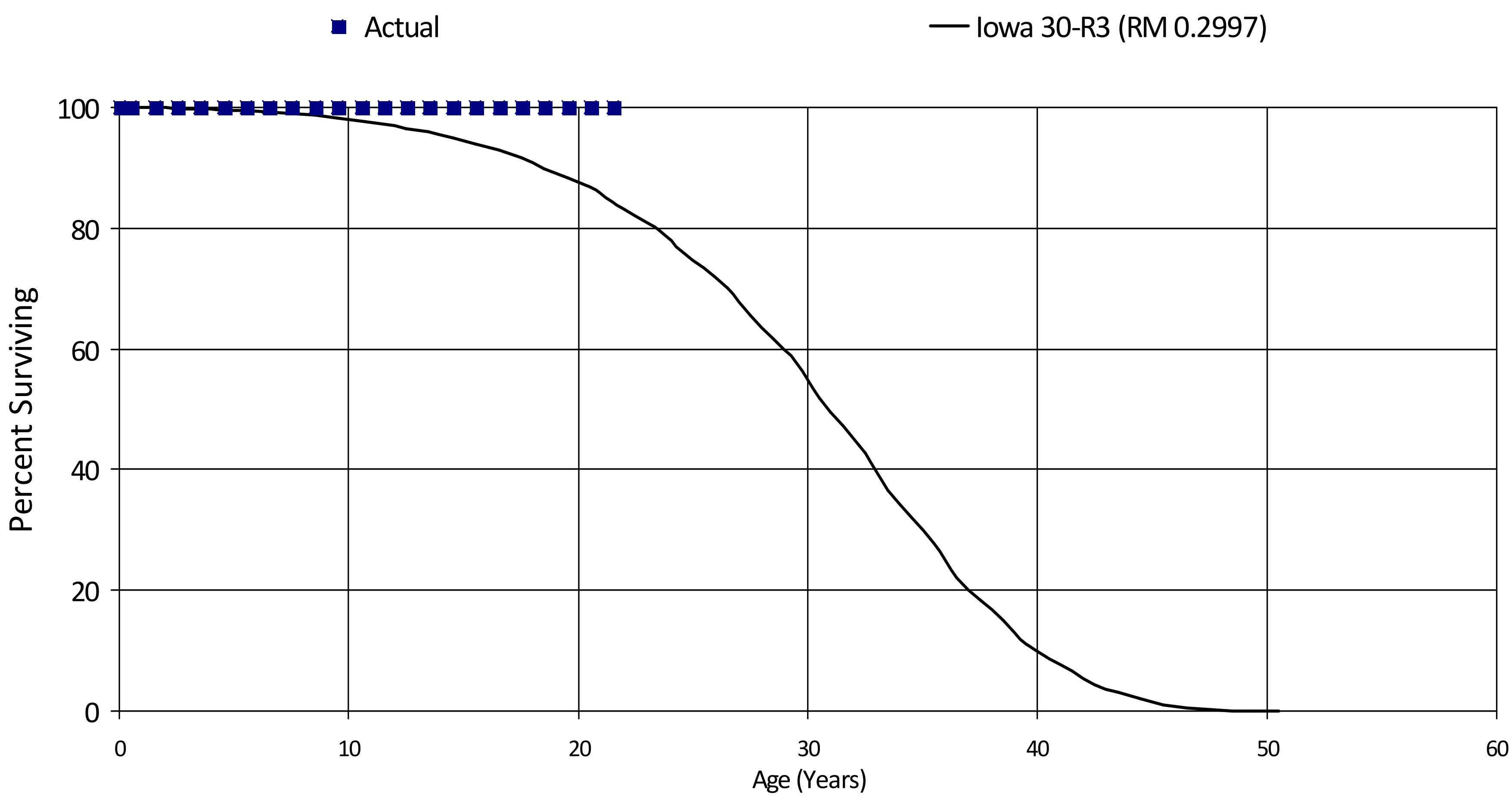
27.5	80,235	0	0.00000	1.00000	100.00
28.5	79,253	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 75202 - Tank, Fiberglass, Double Bottom, Fuel

Placement Band - 1998 - 2020 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 75202 - Tank, Fiberglass, Double Bottom, Fuel

Placement Band - 1998 - 2020 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

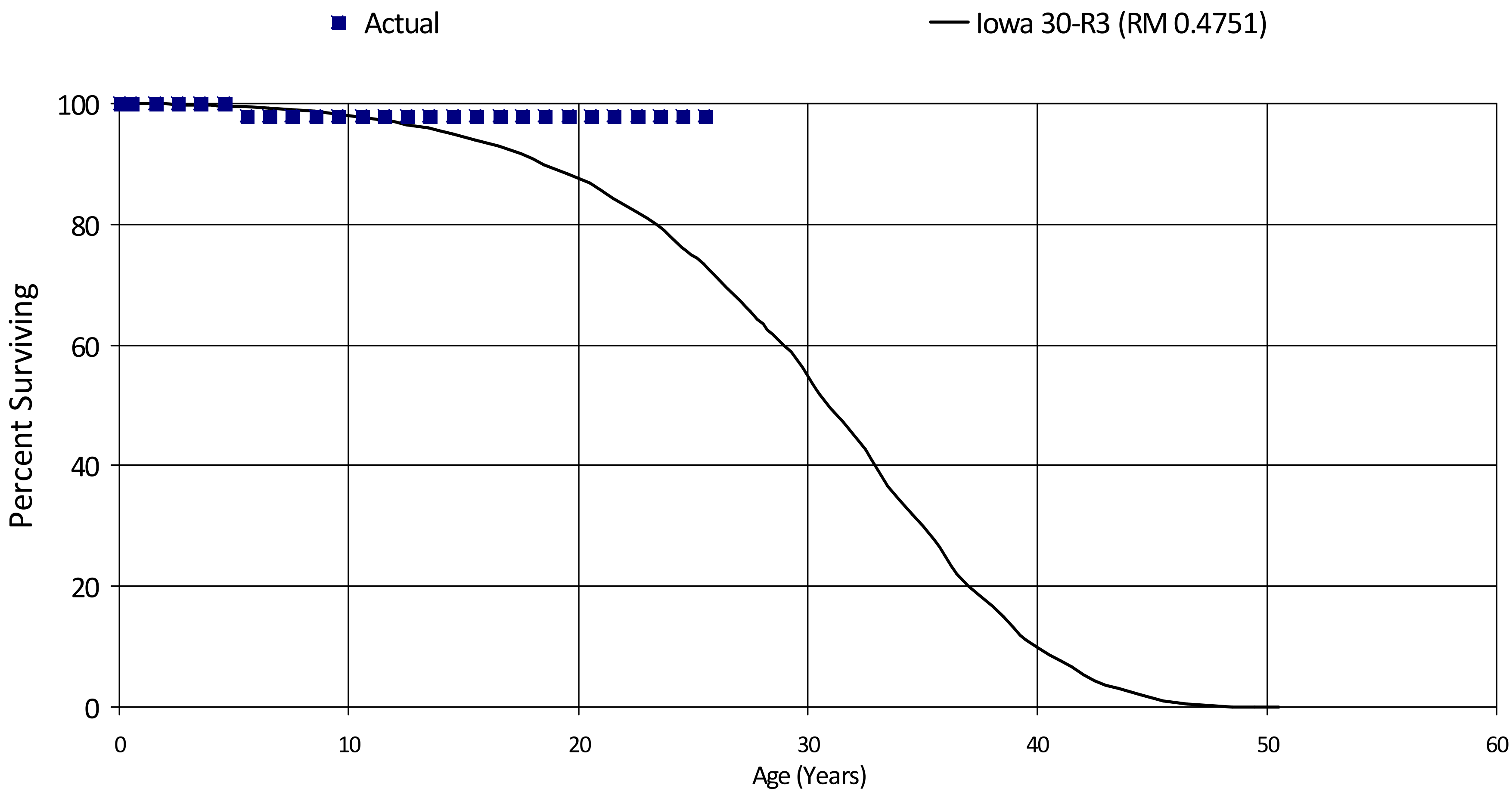
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,503,351	0	0.00000	1.00000	100.00
0.5	1,427,687	0	0.00000	1.00000	100.00
1.5	1,427,687	0	0.00000	1.00000	100.00
2.5	1,427,687	0	0.00000	1.00000	100.00
3.5	1,427,687	0	0.00000	1.00000	100.00
4.5	849,801	0	0.00000	1.00000	100.00
5.5	849,801	0	0.00000	1.00000	100.00
6.5	849,801	0	0.00000	1.00000	100.00
7.5	830,533	0	0.00000	1.00000	100.00
8.5	830,533	0	0.00000	1.00000	100.00
9.5	801,573	0	0.00000	1.00000	100.00
10.5	801,573	0	0.00000	1.00000	100.00
11.5	801,573	0	0.00000	1.00000	100.00
12.5	454,316	0	0.00000	1.00000	100.00
13.5	454,316	0	0.00000	1.00000	100.00
14.5	454,316	0	0.00000	1.00000	100.00
15.5	316,690	0	0.00000	1.00000	100.00
16.5	316,690	0	0.00000	1.00000	100.00
17.5	316,690	0	0.00000	1.00000	100.00
18.5	316,690	0	0.00000	1.00000	100.00
19.5	316,690	0	0.00000	1.00000	100.00
20.5	229,735	0	0.00000	1.00000	100.00
21.5	213,044	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 75203 - Tank, Air - Stainless / Oil - Steel

Placement Band - 1994 - 2019   Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 75203 - Tank, Air - Stainless / Oil - Steel

Placement Band - 1994 - 2019   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

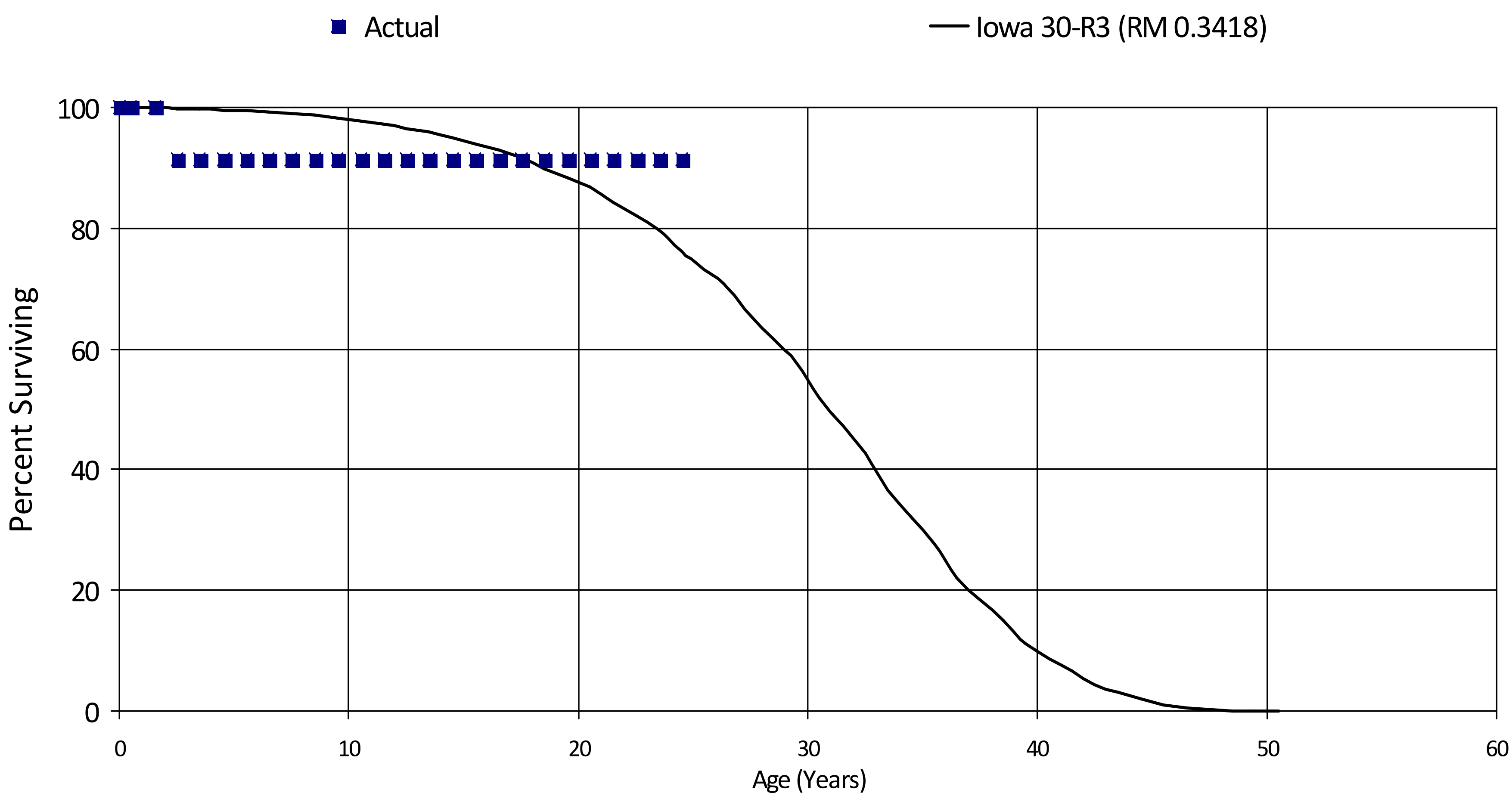
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	6,346,659	0	0.00000	1.00000	100.00
0.5	6,346,659	0	0.00000	1.00000	100.00
1.5	6,284,863	0	0.00000	1.00000	100.00
2.5	5,813,619	0	0.00000	1.00000	100.00
3.5	4,924,465	0	0.00000	1.00000	100.00
4.5	4,261,019	84,818	0.01991	0.98009	100.00
5.5	4,176,201	0	0.00000	1.00000	98.01
6.5	4,176,201	0	0.00000	1.00000	98.01
7.5	4,176,201	0	0.00000	1.00000	98.01
8.5	3,375,900	0	0.00000	1.00000	98.01
9.5	3,375,900	0	0.00000	1.00000	98.01
10.5	1,965,463	0	0.00000	1.00000	98.01
11.5	1,952,605	0	0.00000	1.00000	98.01
12.5	1,505,540	0	0.00000	1.00000	98.01
13.5	1,483,758	0	0.00000	1.00000	98.01
14.5	977,453	0	0.00000	1.00000	98.01
15.5	462,761	0	0.00000	1.00000	98.01
16.5	324,267	0	0.00000	1.00000	98.01
17.5	298,497	0	0.00000	1.00000	98.01
18.5	298,497	0	0.00000	1.00000	98.01
19.5	269,154	0	0.00000	1.00000	98.01
20.5	254,454	0	0.00000	1.00000	98.01
21.5	226,366	0	0.00000	1.00000	98.01
22.5	226,366	0	0.00000	1.00000	98.01
23.5	143,712	0	0.00000	1.00000	98.01
24.5	106,294	0	0.00000	1.00000	98.01
25.5	105,741	0	0.00000	1.00000	98.01
	Totals:	84,818			

BC Hydro Power Authority

Account 75204 - Tanks, Concrete

Placement Band - 1995 - 2018 Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 75204 - Tanks, Concrete

Placement Band - 1995 - 2018   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

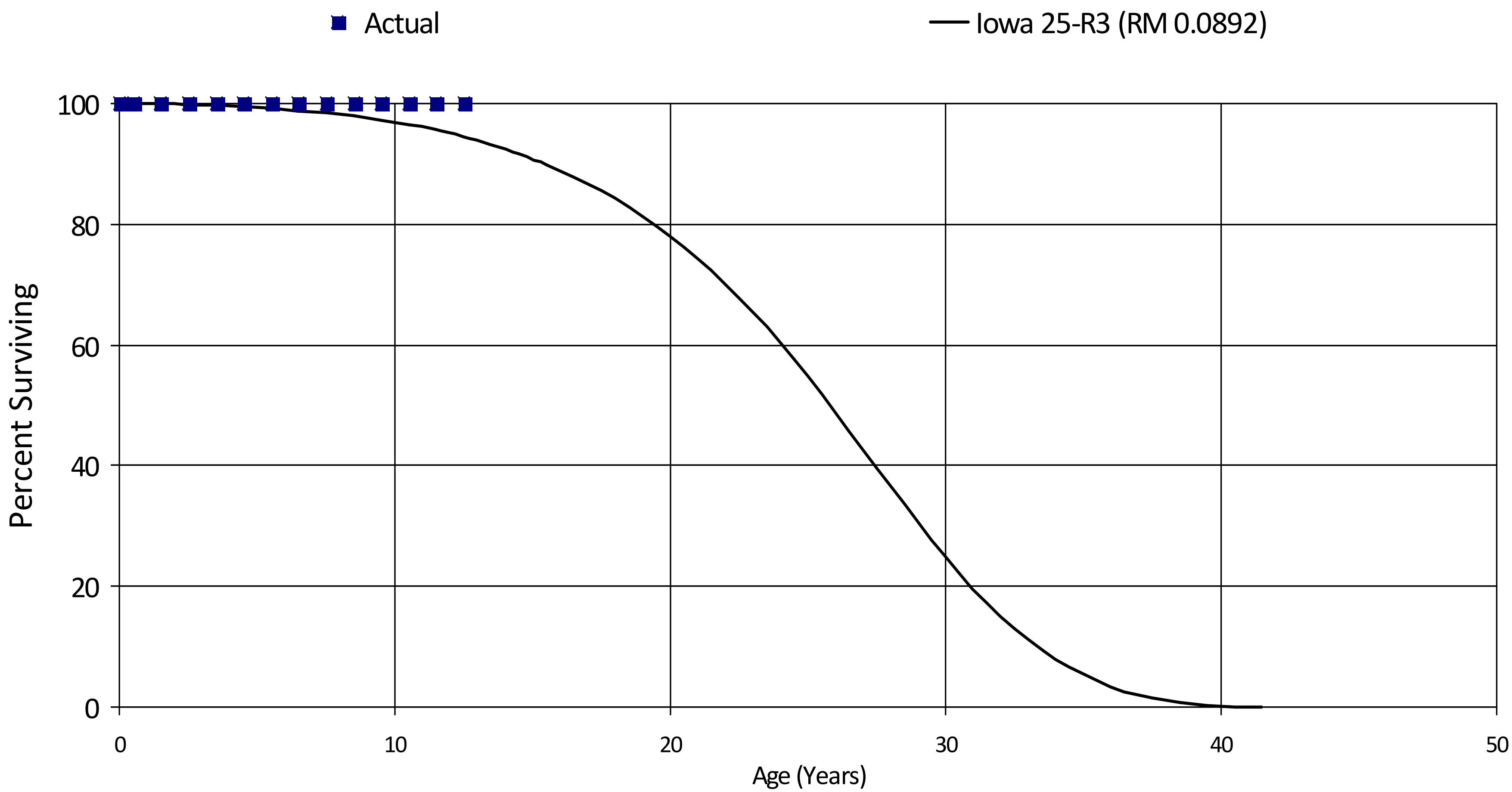
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,286,744	0	0.00000	1.00000	100.00
0.5	2,286,744	0	0.00000	1.00000	100.00
1.5	2,286,744	197,102	0.08619	0.91381	100.00
2.5	1,612,203	0	0.00000	1.00000	91.38
3.5	1,320,967	0	0.00000	1.00000	91.38
4.5	1,320,967	0	0.00000	1.00000	91.38
5.5	1,320,967	0	0.00000	1.00000	91.38
6.5	1,276,611	0	0.00000	1.00000	91.38
7.5	1,276,611	0	0.00000	1.00000	91.38
8.5	1,276,611	0	0.00000	1.00000	91.38
9.5	1,276,611	0	0.00000	1.00000	91.38
10.5	1,276,611	0	0.00000	1.00000	91.38
11.5	1,276,611	0	0.00000	1.00000	91.38
12.5	1,276,611	0	0.00000	1.00000	91.38
13.5	1,276,611	0	0.00000	1.00000	91.38
14.5	1,276,611	0	0.00000	1.00000	91.38
15.5	1,276,611	0	0.00000	1.00000	91.38
16.5	1,276,611	0	0.00000	1.00000	91.38
17.5	1,040,179	0	0.00000	1.00000	91.38
18.5	593,450	0	0.00000	1.00000	91.38
19.5	593,450	0	0.00000	1.00000	91.38
20.5	158,964	0	0.00000	1.00000	91.38
21.5	82,798	0	0.00000	1.00000	91.38
22.5	82,798	0	0.00000	1.00000	91.38
23.5	59,849	0	0.00000	1.00000	91.38
24.5	38,202	0	0.00000	1.00000	91.38
	Totals:	197,102			

BC Hydro Power Authority

Account 75205 - Tanks, Wood

Placement Band - 2007 - 2007 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 75205 - Tanks, Wood

Placement Band - 2007 - 2007   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

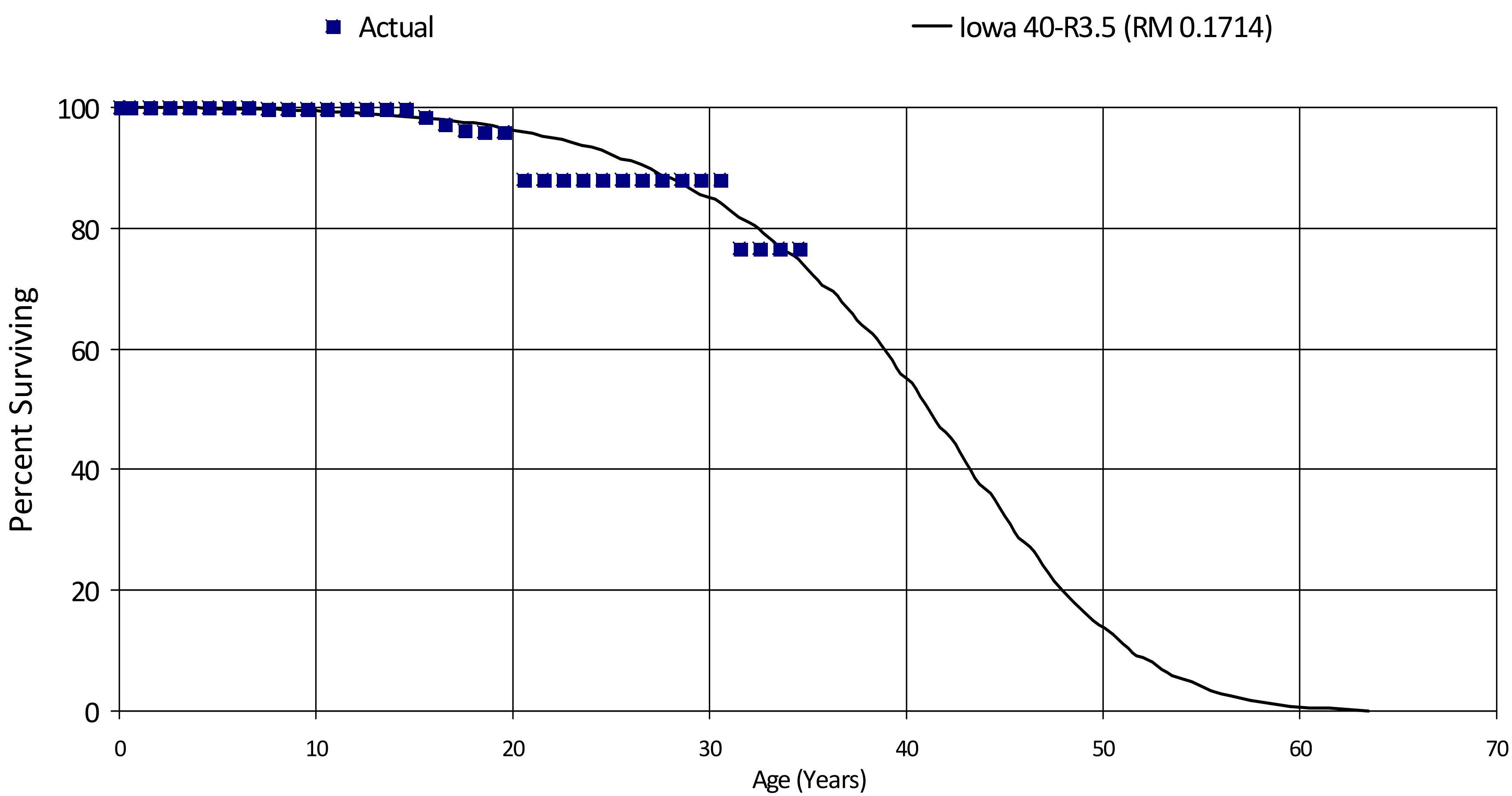
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	182,035	0	0.00000	1.00000	100.00
0.5	182,035	0	0.00000	1.00000	100.00
1.5	182,035	0	0.00000	1.00000	100.00
2.5	182,035	0	0.00000	1.00000	100.00
3.5	182,035	0	0.00000	1.00000	100.00
4.5	182,035	0	0.00000	1.00000	100.00
5.5	182,035	0	0.00000	1.00000	100.00
6.5	182,035	0	0.00000	1.00000	100.00
7.5	182,035	0	0.00000	1.00000	100.00
8.5	182,035	0	0.00000	1.00000	100.00
9.5	182,035	0	0.00000	1.00000	100.00
10.5	182,035	0	0.00000	1.00000	100.00
11.5	182,035	0	0.00000	1.00000	100.00
12.5	182,035	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 75301 - Water Supply System

Placement Band - 1972 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 75301 - Water Supply System

Placement Band - 1972 - 2020   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	25,994,329	0	0.00000	1.00000	100.00
0.5	25,684,423	0	0.00000	1.00000	100.00
1.5	24,774,665	0	0.00000	1.00000	100.00
2.5	24,035,540	0	0.00000	1.00000	100.00
3.5	23,349,322	0	0.00000	1.00000	100.00
4.5	21,767,521	0	0.00000	1.00000	100.00
5.5	21,641,740	7,202	0.00033	0.99967	100.00
6.5	20,348,497	28,806	0.00142	0.99858	99.97
7.5	20,319,691	0	0.00000	1.00000	99.83
8.5	13,474,040	16,571	0.00123	0.99877	99.83
9.5	10,063,414	0	0.00000	1.00000	99.71
10.5	8,018,796	0	0.00000	1.00000	99.71
11.5	7,863,709	0	0.00000	1.00000	99.71
12.5	7,863,709	1,926	0.00024	0.99976	99.71
13.5	7,861,783	0	0.00000	1.00000	99.69
14.5	3,656,674	48,894	0.01337	0.98663	99.69
15.5	3,607,780	44,234	0.01226	0.98774	98.36
16.5	2,679,579	29,675	0.01107	0.98893	97.15
17.5	2,323,215	304	0.00013	0.99987	96.07
18.5	2,134,651	0	0.00000	1.00000	96.06
19.5	2,123,512	175,889	0.08283	0.91717	96.06
20.5	1,897,504	0	0.00000	1.00000	88.10
21.5	1,067,467	0	0.00000	1.00000	88.10
22.5	1,058,302	0	0.00000	1.00000	88.10
23.5	1,051,724	0	0.00000	1.00000	88.10
24.5	913,212	0	0.00000	1.00000	88.10
25.5	903,899	0	0.00000	1.00000	88.10
26.5	828,313	0	0.00000	1.00000	88.10

BC Hydro Power Authority

Account 75301 - Water Supply System

Placement Band - 1972 - 2020   Experience Band - 2013 - 2020

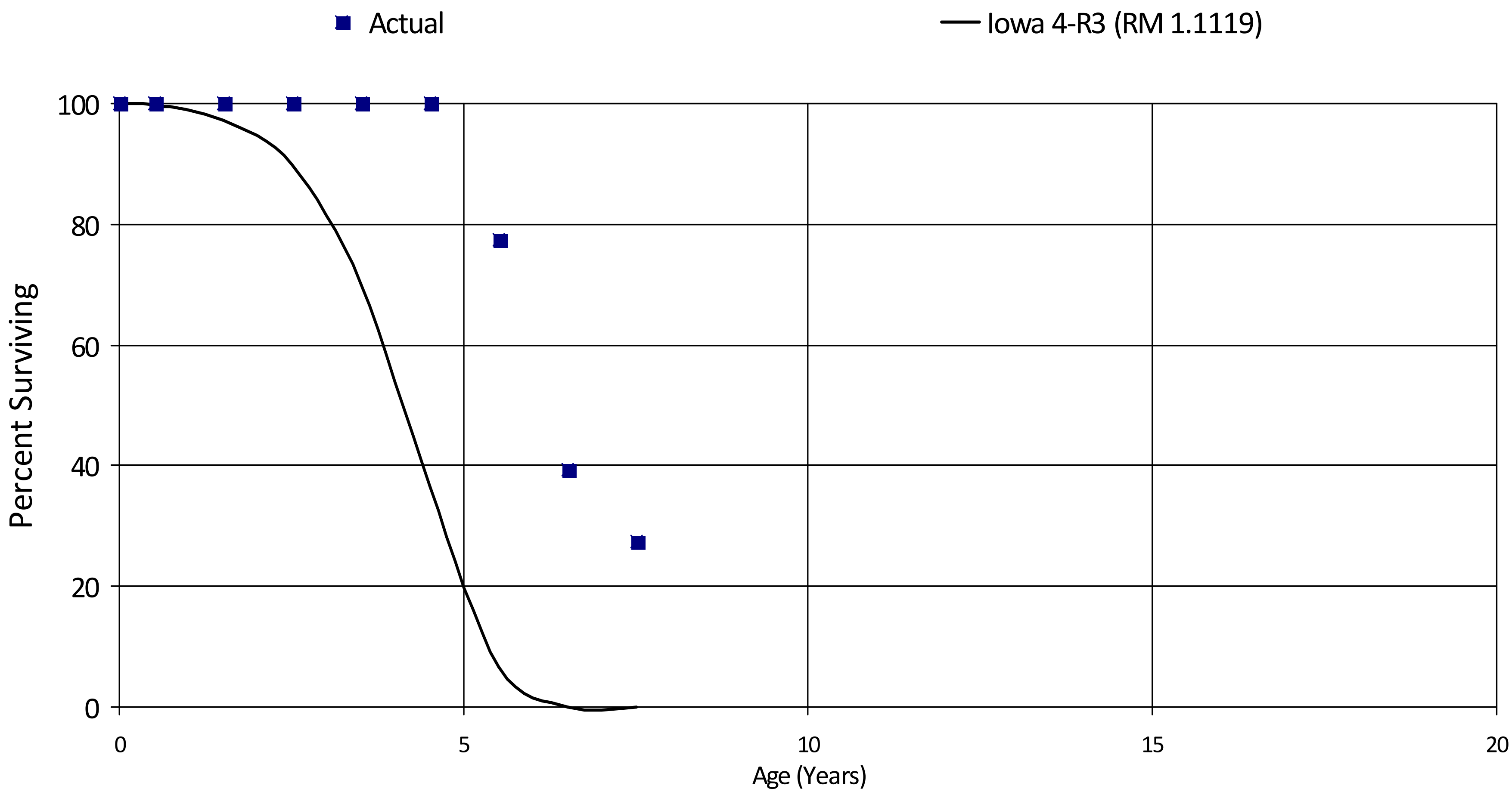
27.5	828,313	0	0.00000	1.00000	88.10
28.5	805,284	0	0.00000	1.00000	88.10
29.5	791,719	0	0.00000	1.00000	88.10
30.5	791,719	102,754	0.12979	0.87021	88.10
31.5	688,965	0	0.00000	1.00000	76.67
32.5	688,965	0	0.00000	1.00000	76.67
33.5	687,357	0	0.00000	1.00000	76.67
34.5	679,813	2,172	0.00319	0.99681	76.67
	Totals:	458,427			

BC Hydro Power Authority

Account 80508 - Misc. Network Equipment

Placement Band - 2008 - 2020   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 80508 - Misc. Network Equipment

Placement Band - 2008 - 2020 Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

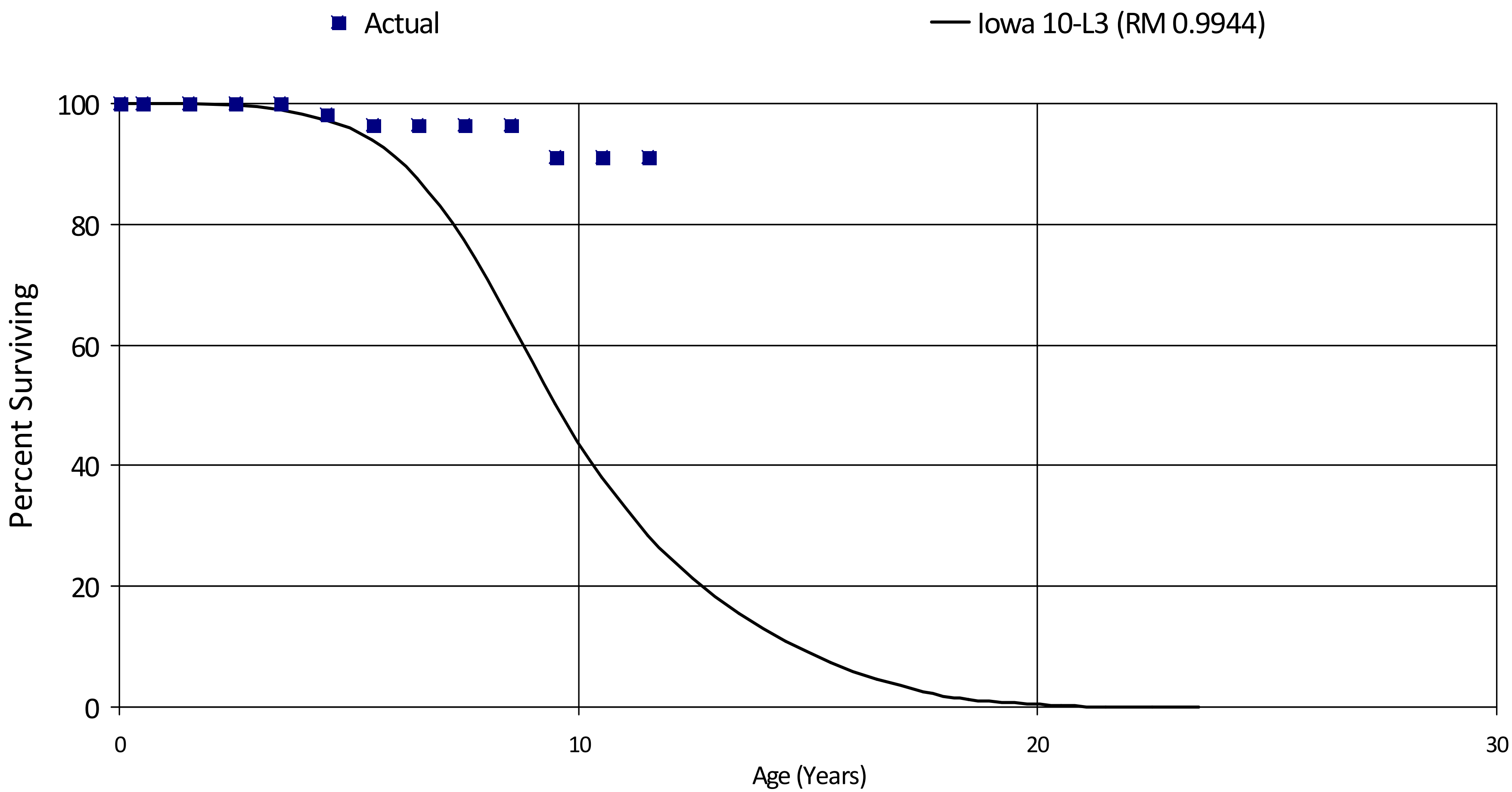
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	24,108,431	0	0.00000	1.00000	100.00
0.5	23,325,575	0	0.00000	1.00000	100.00
1.5	22,251,238	0	0.00000	1.00000	100.00
2.5	20,504,059	0	0.00000	1.00000	100.00
3.5	15,105,973	0	0.00000	1.00000	100.00
4.5	13,210,732	2,976,265	0.22529	0.77471	100.00
5.5	6,806,203	3,345,903	0.49160	0.50840	77.47
6.5	3,460,299	1,053,120	0.30434	0.69566	39.39
7.5	2,407,179	2,407,179	1.00000		27.40
	Totals:	9,782,467			

BC Hydro Power Authority

Account 81001 - Automobiles

Placement Band - 2001 - 2019 Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 81001 - Automobiles

Placement Band - 2001 - 2019   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

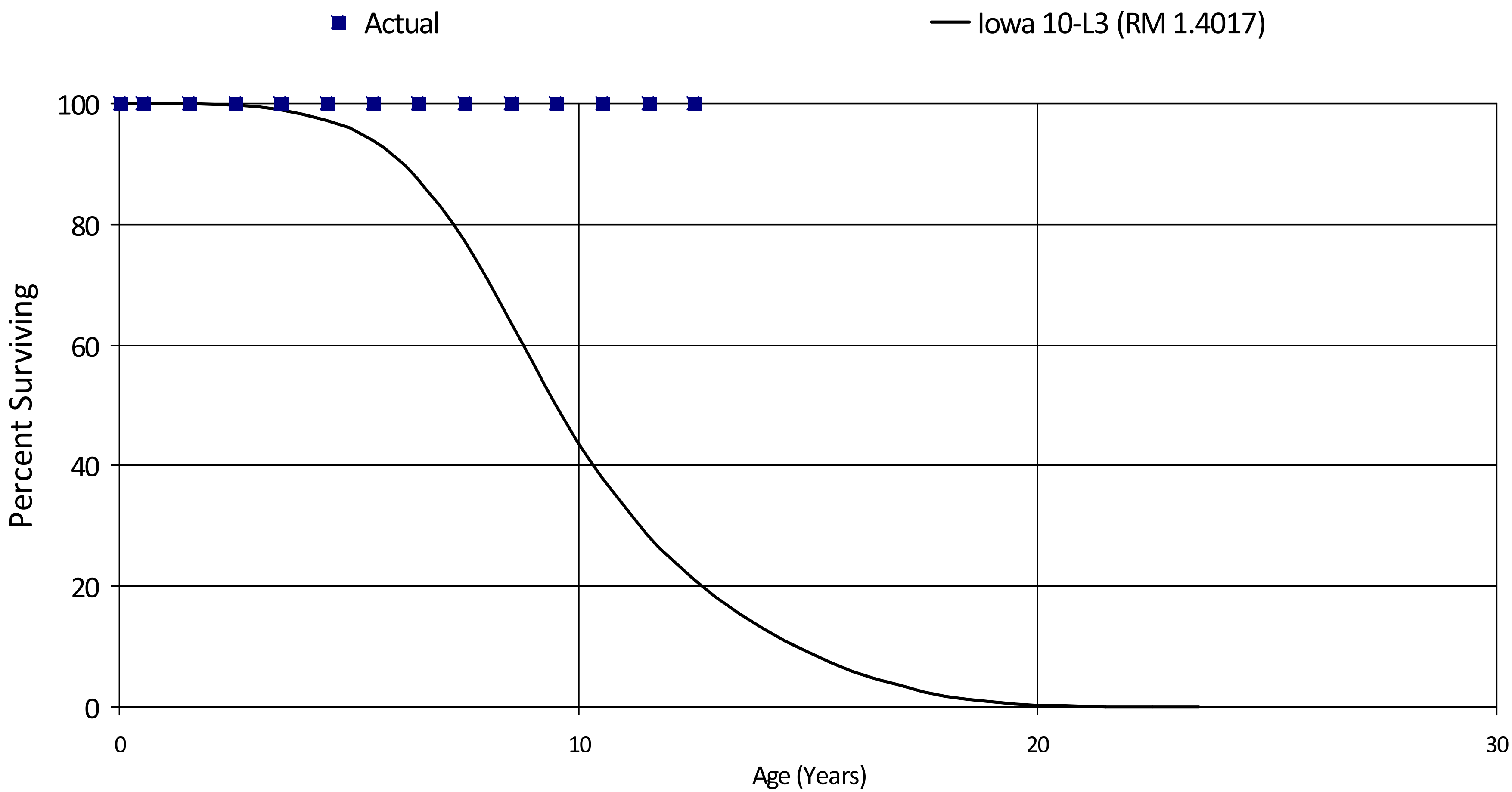
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,036,684	0	0.00000	1.00000	100.00
0.5	2,036,684	0	0.00000	1.00000	100.00
1.5	1,355,605	0	0.00000	1.00000	100.00
2.5	1,066,821	0	0.00000	1.00000	100.00
3.5	983,883	16,366	0.01663	0.98337	100.00
4.5	967,517	18,609	0.01923	0.98077	98.34
5.5	632,559	0	0.00000	1.00000	96.45
6.5	604,611	0	0.00000	1.00000	96.45
7.5	555,070	0	0.00000	1.00000	96.45
8.5	370,626	20,815	0.05616	0.94384	96.45
9.5	79,713	0	0.00000	1.00000	91.03
10.5	49,603	0	0.00000	1.00000	91.03
11.5	28,077	3,019	0.10753	0.89247	91.03
	Totals:	58,809			

BC Hydro Power Authority

Account 81101 - Trucks < 1 Ton 2 Wheel Drive

Placement Band - 1992 - 2019   Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 81101 - Trucks < 1 Ton 2 Wheel Drive

Placement Band - 1992 - 2019   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

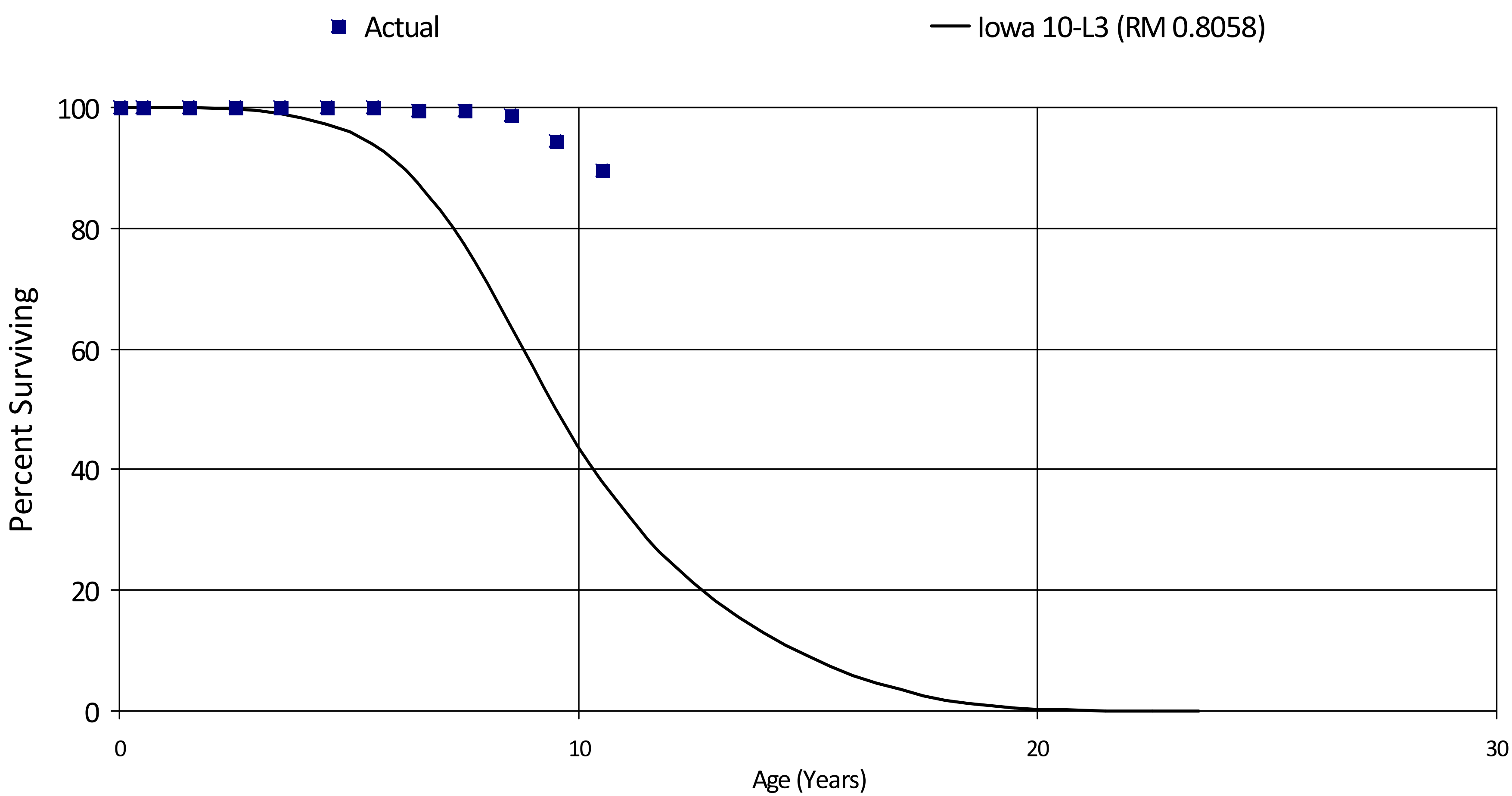
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,945,142	0	0.00000	1.00000	100.00
0.5	1,945,142	0	0.00000	1.00000	100.00
1.5	1,753,423	0	0.00000	1.00000	100.00
2.5	828,101	0	0.00000	1.00000	100.00
3.5	490,415	0	0.00000	1.00000	100.00
4.5	222,718	0	0.00000	1.00000	100.00
5.5	222,718	0	0.00000	1.00000	100.00
6.5	222,718	0	0.00000	1.00000	100.00
7.5	206,477	0	0.00000	1.00000	100.00
8.5	206,477	0	0.00000	1.00000	100.00
9.5	184,346	0	0.00000	1.00000	100.00
10.5	71,944	0	0.00000	1.00000	100.00
11.5	27,014	0	0.00000	1.00000	100.00
12.5	21,005	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 81201 - Trucks < 1 Ton 4 Wheel Drive

Placement Band - 1992 - 2020 Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 81201 - Trucks < 1 Ton 4 Wheel Drive

Placement Band - 1992 - 2020   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

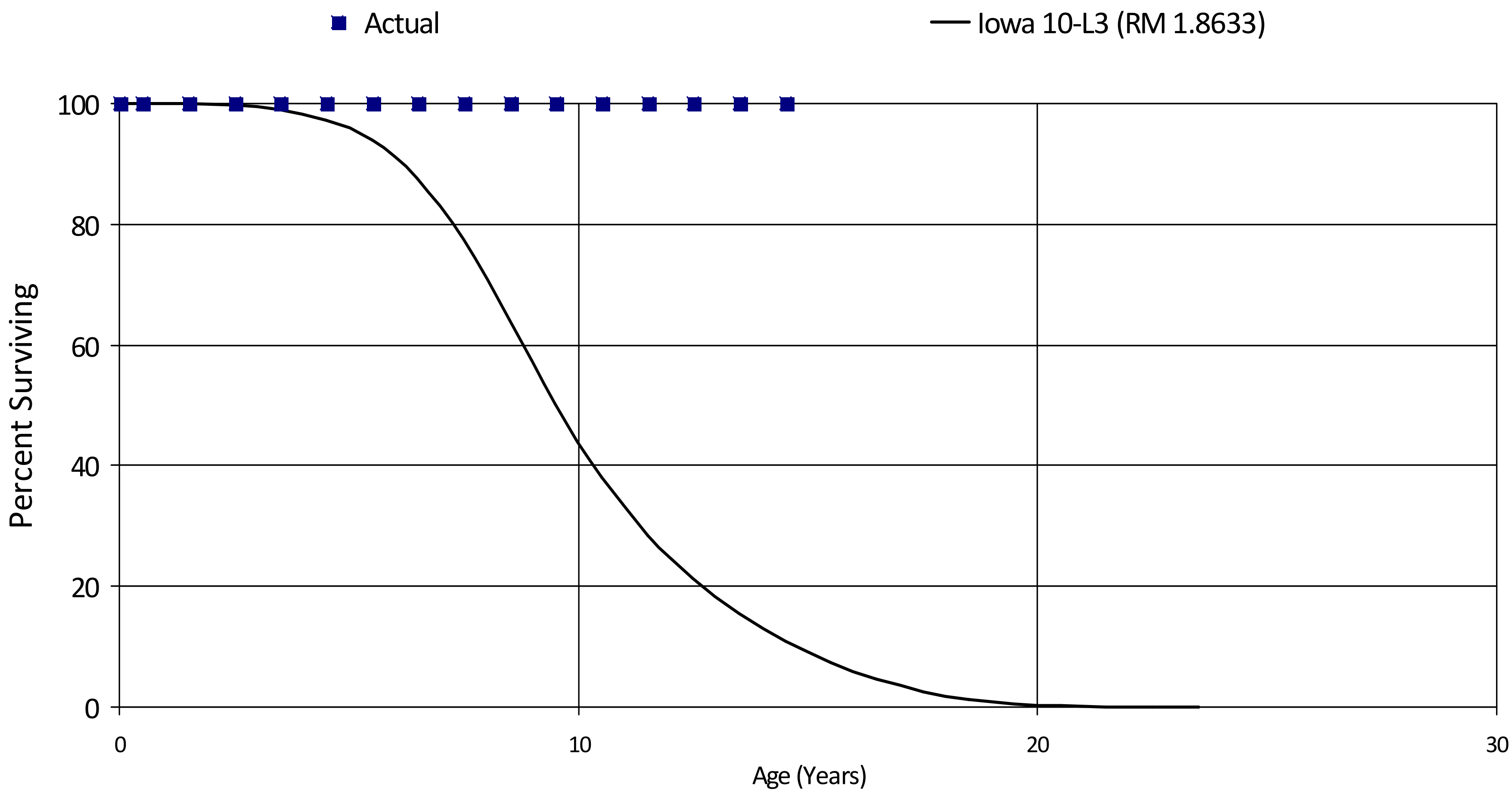
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	39,556,927	0	0.00000	1.00000	100.00
0.5	38,528,953	0	0.00000	1.00000	100.00
1.5	31,619,136	0	0.00000	1.00000	100.00
2.5	21,231,811	0	0.00000	1.00000	100.00
3.5	16,698,546	0	0.00000	1.00000	100.00
4.5	10,344,779	0	0.00000	1.00000	100.00
5.5	8,436,780	32,579	0.00386	0.99614	100.00
6.5	5,019,695	0	0.00000	1.00000	99.61
7.5	4,168,880	37,390	0.00897	0.99103	99.61
8.5	1,917,643	84,821	0.04423	0.95577	98.72
9.5	1,074,568	54,695	0.05090	0.94910	94.35
10.5	537,091	27,213	0.05067	0.94933	89.55
	Totals:	236,698			

BC Hydro Power Authority

Account 81301 - Trucks > = 1 Ton 2 Wheel Drive

Placement Band - 1985 - 2020 Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 81301 - Trucks > = 1 Ton 2 Wheel Drive

Placement Band - 1985 - 2020   Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

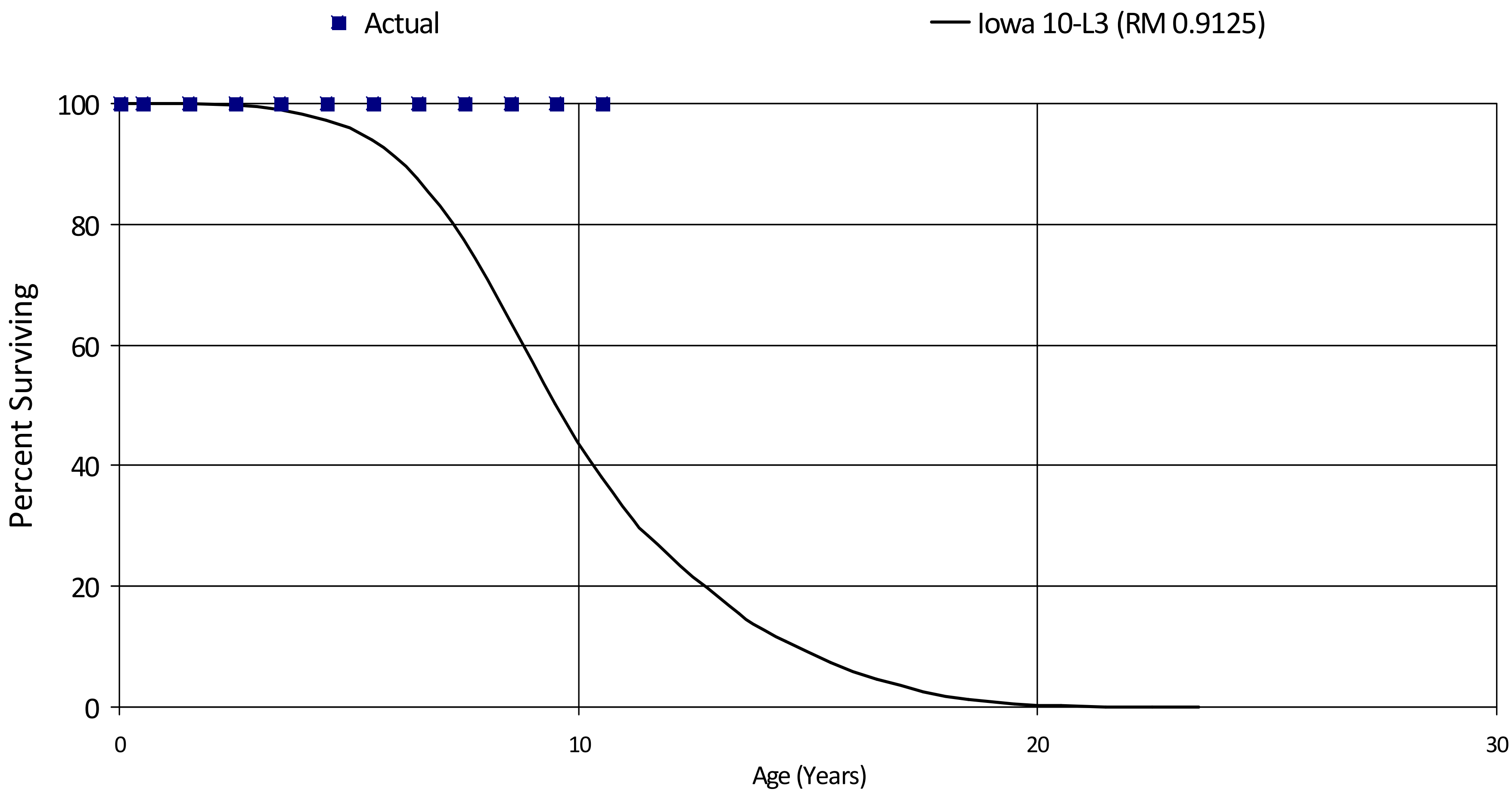
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	14,286,403	0	0.00000	1.00000	100.00
0.5	14,048,086	0	0.00000	1.00000	100.00
1.5	12,579,503	0	0.00000	1.00000	100.00
2.5	11,101,384	0	0.00000	1.00000	100.00
3.5	9,217,225	0	0.00000	1.00000	100.00
4.5	8,195,773	0	0.00000	1.00000	100.00
5.5	8,195,773	0	0.00000	1.00000	100.00
6.5	7,762,381	0	0.00000	1.00000	100.00
7.5	7,669,289	0	0.00000	1.00000	100.00
8.5	5,702,753	0	0.00000	1.00000	100.00
9.5	5,243,564	0	0.00000	1.00000	100.00
10.5	3,834,117	0	0.00000	1.00000	100.00
11.5	2,026,829	0	0.00000	1.00000	100.00
12.5	977,937	0	0.00000	1.00000	100.00
13.5	412,056	0	0.00000	1.00000	100.00
14.5	211,152	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 81302 - Trucks > = 1 Ton 2 Wheel Drive

Placement Band - 2008 - 2011   Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 81302 - Trucks > = 1 Ton 2 Wheel Drive

Placement Band - 2008 - 2011   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

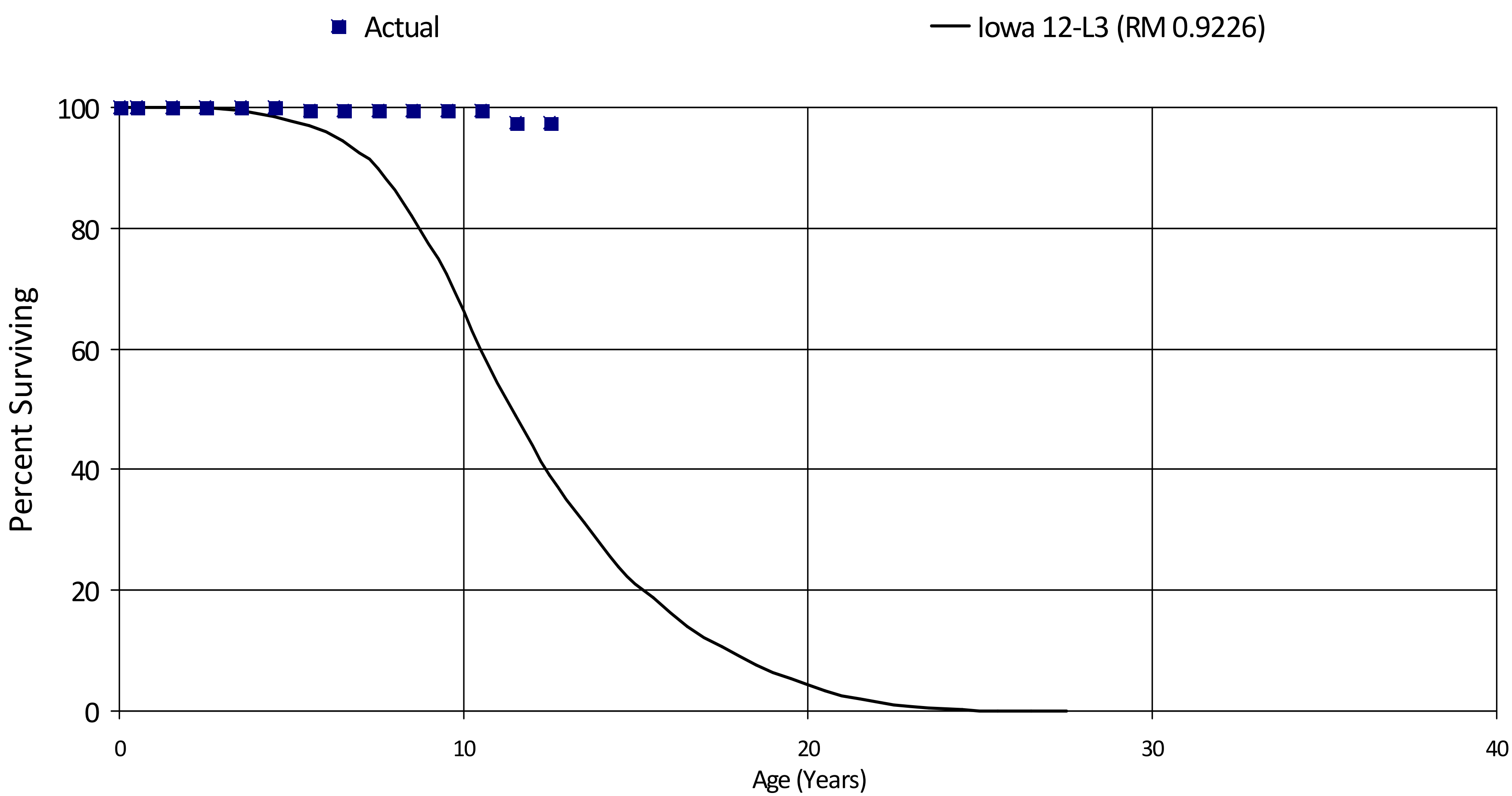
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,723,873	0	0.00000	1.00000	100.00
0.5	1,723,873	0	0.00000	1.00000	100.00
1.5	1,723,873	0	0.00000	1.00000	100.00
2.5	1,723,873	0	0.00000	1.00000	100.00
3.5	1,723,873	0	0.00000	1.00000	100.00
4.5	1,723,873	0	0.00000	1.00000	100.00
5.5	1,723,873	0	0.00000	1.00000	100.00
6.5	1,723,873	0	0.00000	1.00000	100.00
7.5	1,723,873	0	0.00000	1.00000	100.00
8.5	1,723,873	0	0.00000	1.00000	100.00
9.5	812,181	0	0.00000	1.00000	100.00
10.5	477,823	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 81401 - Trucks > = 1 Ton 4 Wheel Drive

Placement Band - 1991 - 2020   Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 81401 - Trucks > = 1 Ton 4 Wheel Drive

Placement Band - 1991 - 2020 Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

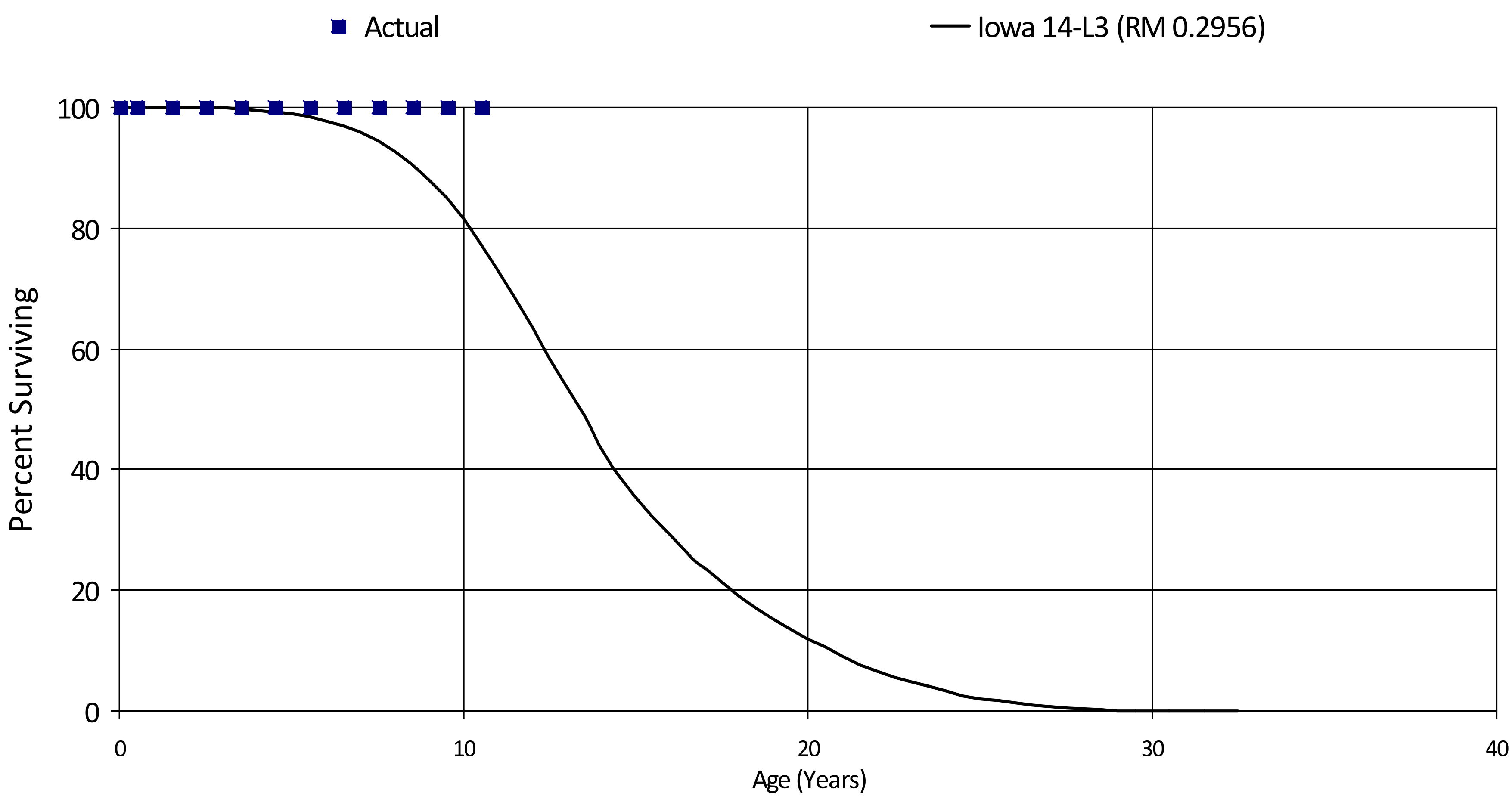
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	65,484,994	0	0.00000	1.00000	100.00
0.5	60,646,900	21,700	0.00036	0.99964	100.00
1.5	52,227,581	0	0.00000	1.00000	99.96
2.5	44,339,369	0	0.00000	1.00000	99.96
3.5	36,887,658	0	0.00000	1.00000	99.96
4.5	22,701,171	115,871	0.00510	0.99490	99.96
5.5	21,548,668	0	0.00000	1.00000	99.45
6.5	20,156,854	0	0.00000	1.00000	99.45
7.5	18,847,579	0	0.00000	1.00000	99.45
8.5	13,362,658	0	0.00000	1.00000	99.45
9.5	10,272,561	0	0.00000	1.00000	99.45
10.5	6,690,341	131,525	0.01966	0.98034	99.45
11.5	3,436,588	0	0.00000	1.00000	97.49
12.5	1,773,872	0	0.00000	1.00000	97.49
	Totals:	269,096			

BC Hydro Power Authority

Account 81501 - Trucks > = 1 Ton 6 Wheel Drive

Placement Band - 2005 - 2019 Experience Band - 2016 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 81501 - Trucks > = 1 Ton 6 Wheel Drive

Placement Band - 2005 - 2019 Experience Band - 2016 - 2020

RETIREMENT RATE ANALYSIS

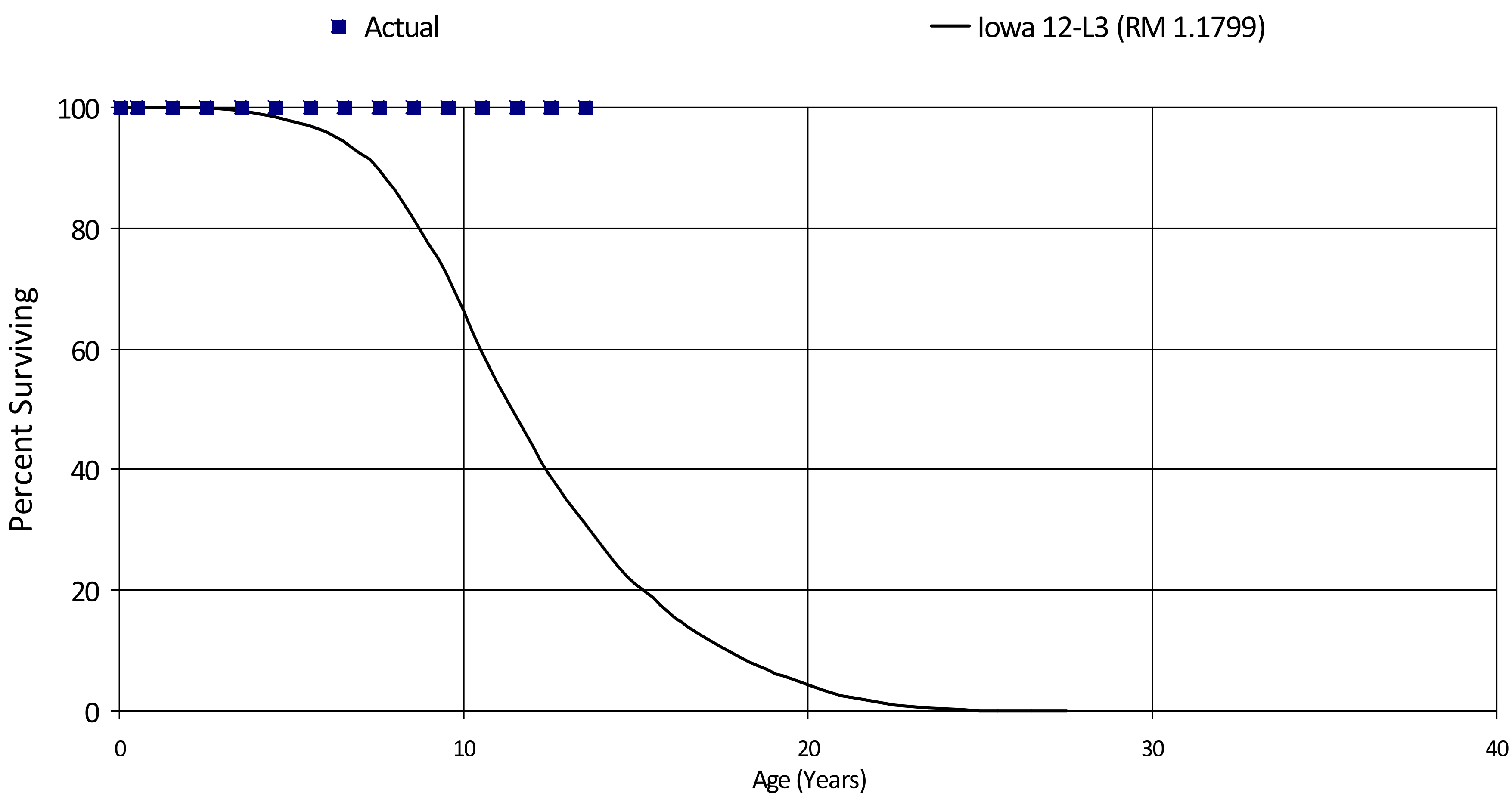
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	24,932,335	0	0.00000	1.00000	100.00
0.5	24,932,335	0	0.00000	1.00000	100.00
1.5	23,745,167	0	0.00000	1.00000	100.00
2.5	23,497,043	0	0.00000	1.00000	100.00
3.5	23,325,014	0	0.00000	1.00000	100.00
4.5	11,904,500	0	0.00000	1.00000	100.00
5.5	10,578,089	0	0.00000	1.00000	100.00
6.5	9,153,083	0	0.00000	1.00000	100.00
7.5	8,990,750	0	0.00000	1.00000	100.00
8.5	6,767,443	0	0.00000	1.00000	100.00
9.5	4,146,665	0	0.00000	1.00000	100.00
10.5	479,750	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 81601 - Tractor, Highway

Placement Band - 2003 - 2006 Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 81601 - Tractor, Highway

Placement Band - 2003 - 2006   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

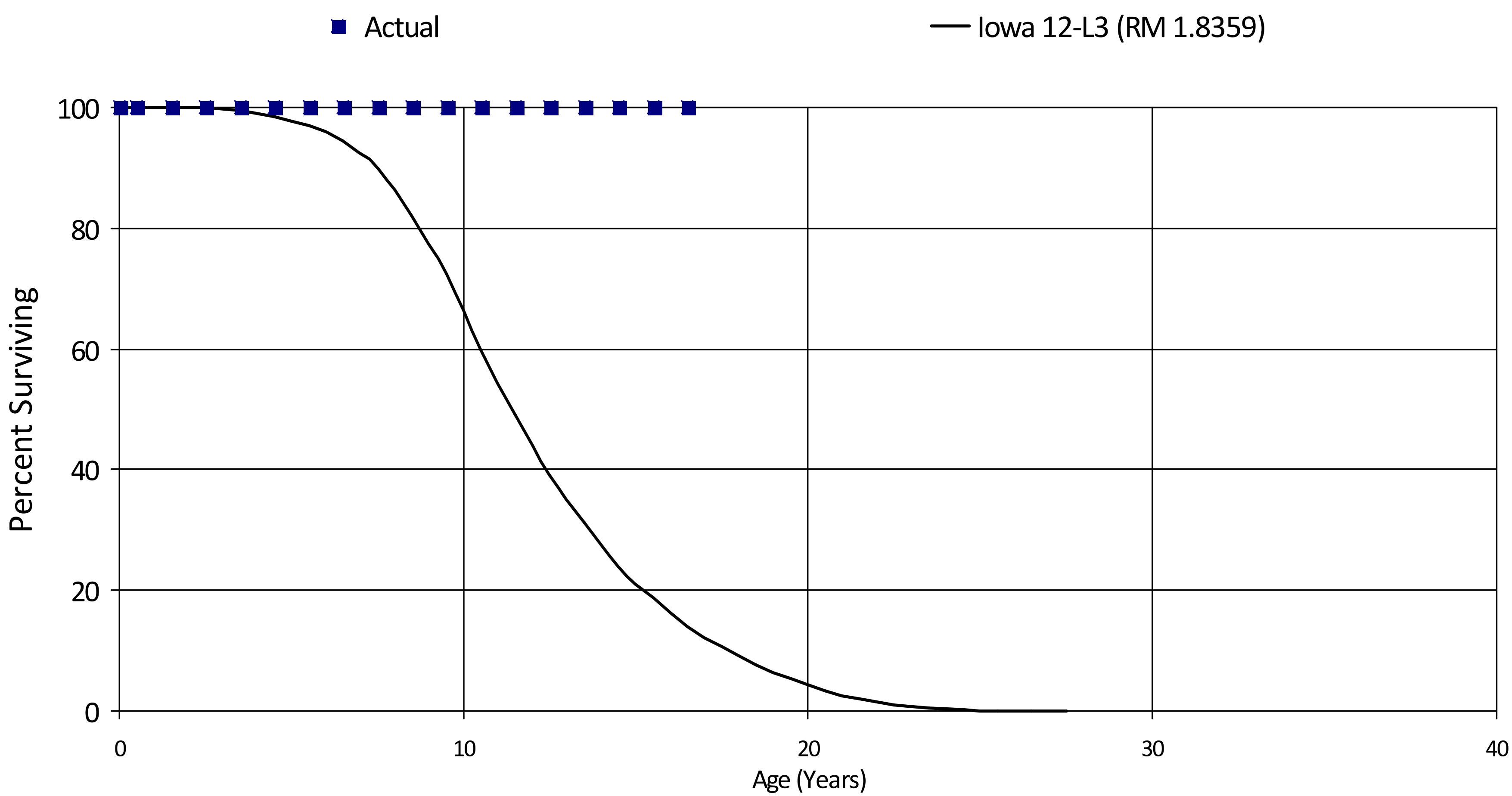
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	27,949	0	0.00000	1.00000	100.00
0.5	27,949	0	0.00000	1.00000	100.00
1.5	27,949	0	0.00000	1.00000	100.00
2.5	27,949	0	0.00000	1.00000	100.00
3.5	27,949	0	0.00000	1.00000	100.00
4.5	27,949	0	0.00000	1.00000	100.00
5.5	27,949	0	0.00000	1.00000	100.00
6.5	27,949	0	0.00000	1.00000	100.00
7.5	27,949	0	0.00000	1.00000	100.00
8.5	27,949	0	0.00000	1.00000	100.00
9.5	27,949	0	0.00000	1.00000	100.00
10.5	27,949	0	0.00000	1.00000	100.00
11.5	27,949	0	0.00000	1.00000	100.00
12.5	27,949	0	0.00000	1.00000	100.00
13.5	27,949	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 81701 - Aerial Device

Placement Band - 1957 - 2020 Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 81701 - Aerial Device

Placement Band - 1957 - 2020   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

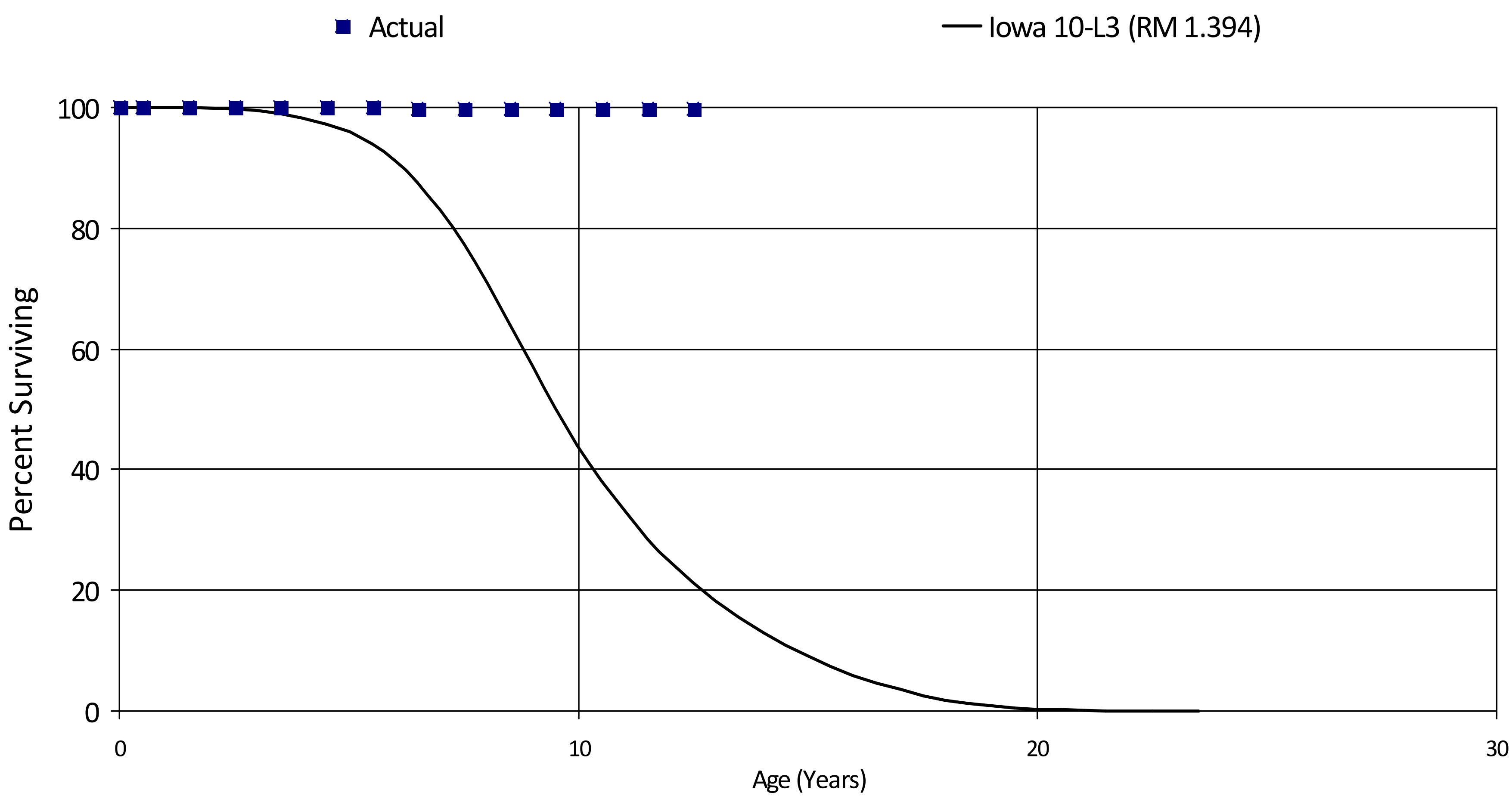
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	23,385,331	0	0.00000	1.00000	100.00
0.5	22,800,309	0	0.00000	1.00000	100.00
1.5	20,726,649	0	0.00000	1.00000	100.00
2.5	18,279,949	0	0.00000	1.00000	100.00
3.5	14,914,487	0	0.00000	1.00000	100.00
4.5	10,287,604	0	0.00000	1.00000	100.00
5.5	9,479,325	0	0.00000	1.00000	100.00
6.5	8,458,413	0	0.00000	1.00000	100.00
7.5	8,284,858	0	0.00000	1.00000	100.00
8.5	6,653,110	0	0.00000	1.00000	100.00
9.5	4,961,626	0	0.00000	1.00000	100.00
10.5	2,933,949	0	0.00000	1.00000	100.00
11.5	1,831,490	0	0.00000	1.00000	100.00
12.5	1,078,758	0	0.00000	1.00000	100.00
13.5	483,059	0	0.00000	1.00000	100.00
14.5	246,442	0	0.00000	1.00000	100.00
15.5	246,442	0	0.00000	1.00000	100.00
16.5	246,442	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 81702 - Line / Service / Van Body

Placement Band - 1985 - 2020   Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 81702 - Line / Service / Van Body

Placement Band - 1985 - 2020   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

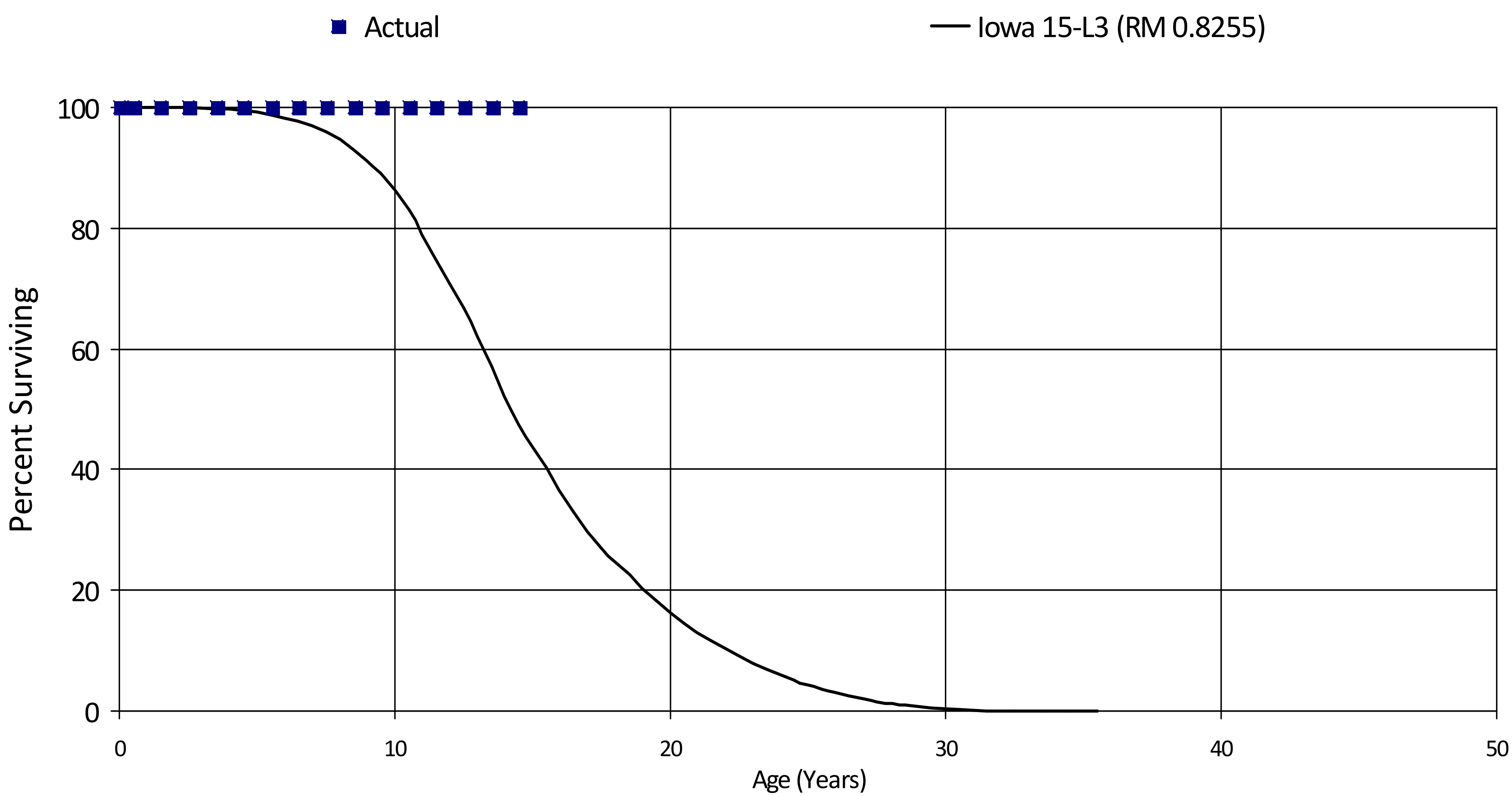
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	31,486,838	0	0.00000	1.00000	100.00
0.5	30,035,482	0	0.00000	1.00000	100.00
1.5	24,538,816	0	0.00000	1.00000	100.00
2.5	19,453,609	0	0.00000	1.00000	100.00
3.5	10,474,720	0	0.00000	1.00000	100.00
4.5	8,063,858	0	0.00000	1.00000	100.00
5.5	7,562,727	12,537	0.00166	0.99834	100.00
6.5	7,045,942	11,296	0.00160	0.99840	99.83
7.5	6,807,215	0	0.00000	1.00000	99.67
8.5	6,146,480	0	0.00000	1.00000	99.67
9.5	4,832,882	0	0.00000	1.00000	99.67
10.5	2,465,101	0	0.00000	1.00000	99.67
11.5	1,070,645	0	0.00000	1.00000	99.67
12.5	500,193	0	0.00000	1.00000	99.67
	Totals:	23,833			

BC Hydro Power Authority

Account 81703 - Derricks / Diggers

Placement Band - 1994 - 2019 Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 81703 - Derricks / Diggers

Placement Band - 1994 - 2019   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

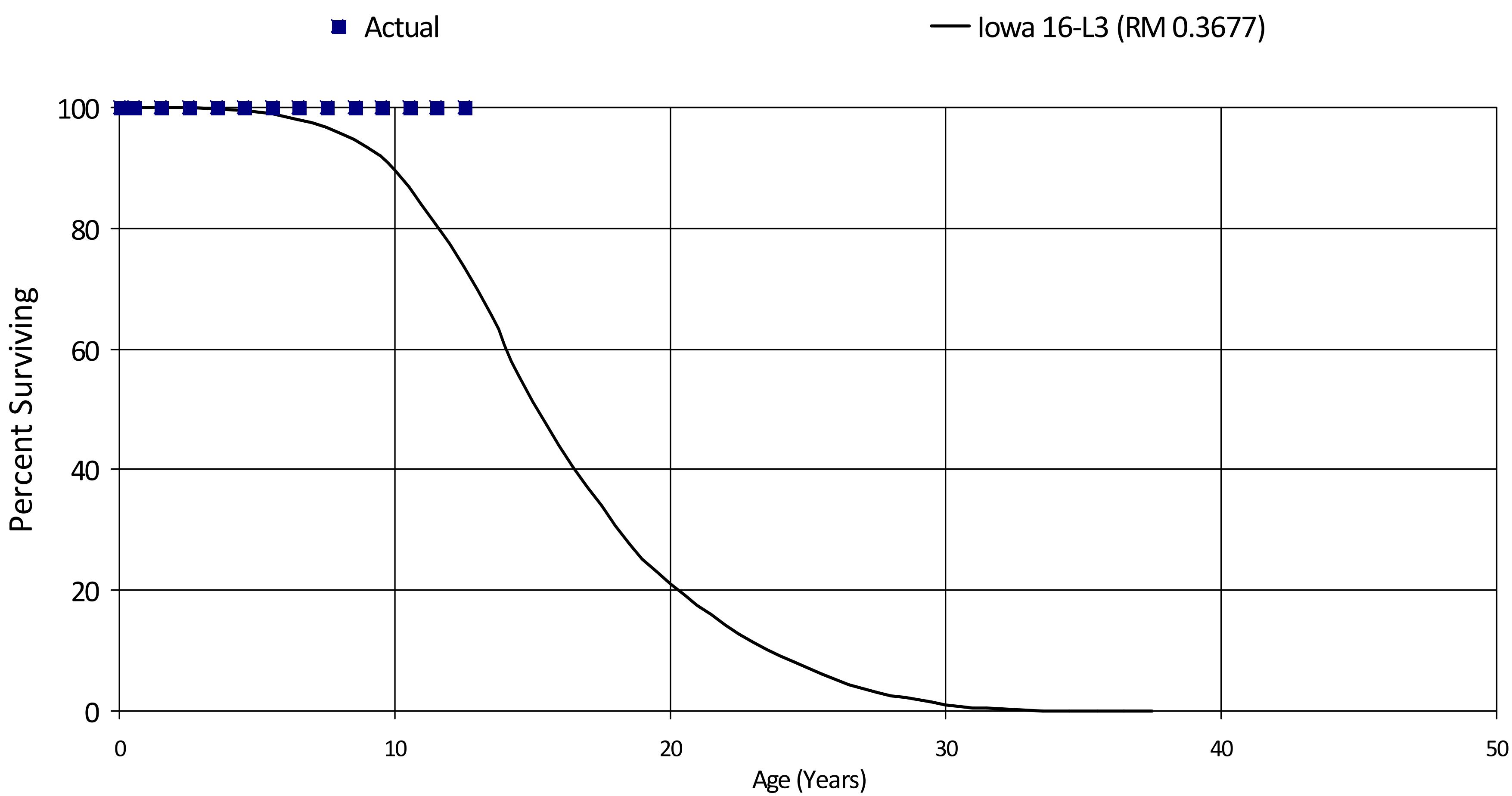
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	19,665,768	0	0.00000	1.00000	100.00
0.5	19,665,768	0	0.00000	1.00000	100.00
1.5	16,382,587	0	0.00000	1.00000	100.00
2.5	15,849,910	0	0.00000	1.00000	100.00
3.5	13,156,237	0	0.00000	1.00000	100.00
4.5	11,576,086	0	0.00000	1.00000	100.00
5.5	10,978,678	0	0.00000	1.00000	100.00
6.5	10,778,956	0	0.00000	1.00000	100.00
7.5	10,272,967	0	0.00000	1.00000	100.00
8.5	9,207,833	0	0.00000	1.00000	100.00
9.5	7,735,714	0	0.00000	1.00000	100.00
10.5	3,517,119	0	0.00000	1.00000	100.00
11.5	1,759,759	0	0.00000	1.00000	100.00
12.5	769,675	0	0.00000	1.00000	100.00
13.5	321,567	0	0.00000	1.00000	100.00
14.5	212,808	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 81704 - Ride-A-Rails

Placement Band - 1969 - 2007 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 81704 - Ride-A-Rails

Placement Band - 1969 - 2007 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

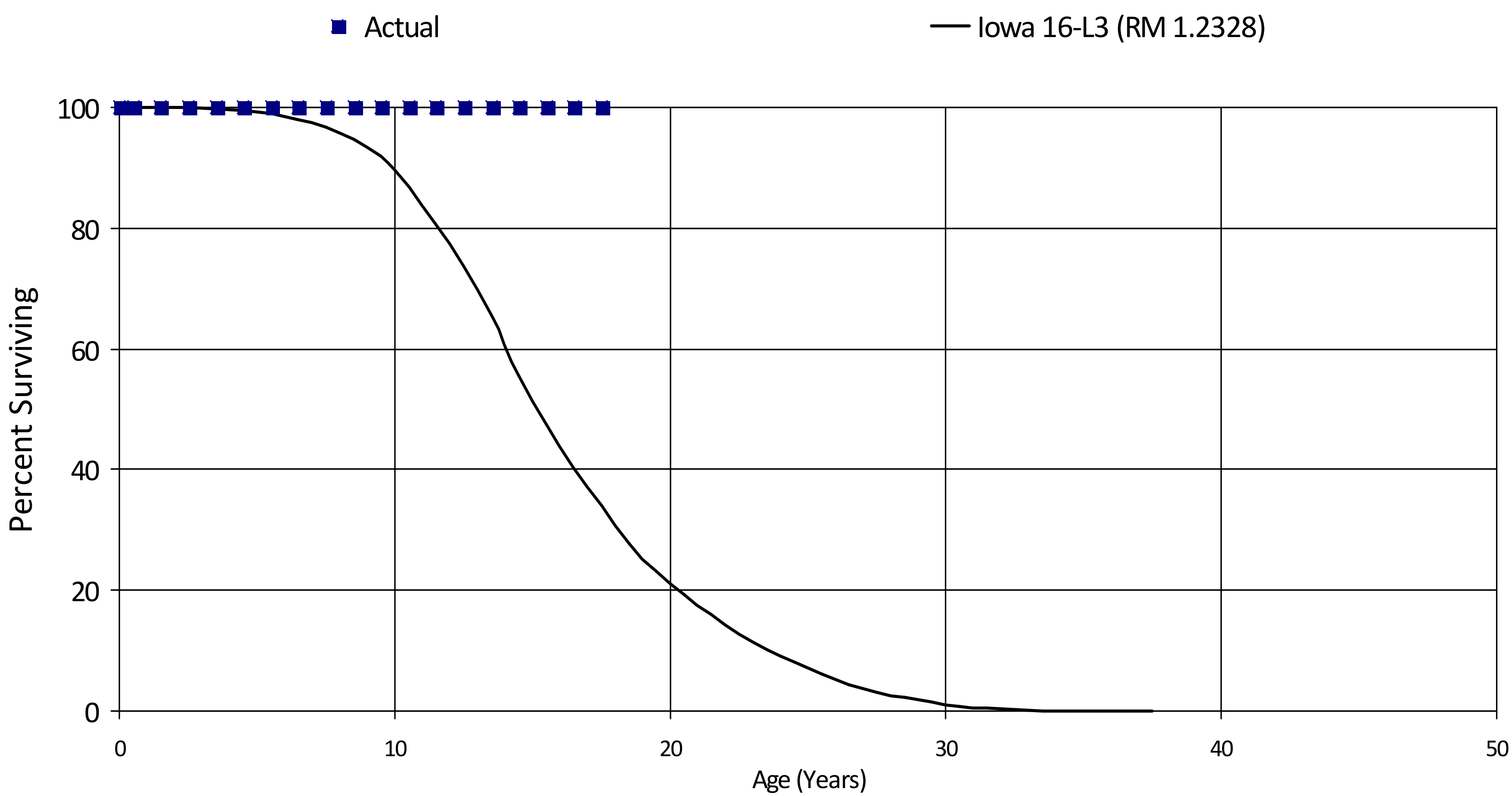
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	34,046	0	0.00000	1.00000	100.00
0.5	34,046	0	0.00000	1.00000	100.00
1.5	34,046	0	0.00000	1.00000	100.00
2.5	34,046	0	0.00000	1.00000	100.00
3.5	34,046	0	0.00000	1.00000	100.00
4.5	34,046	0	0.00000	1.00000	100.00
5.5	34,046	0	0.00000	1.00000	100.00
6.5	34,046	0	0.00000	1.00000	100.00
7.5	34,046	0	0.00000	1.00000	100.00
8.5	34,046	0	0.00000	1.00000	100.00
9.5	34,046	0	0.00000	1.00000	100.00
10.5	34,046	0	0.00000	1.00000	100.00
11.5	34,046	0	0.00000	1.00000	100.00
12.5	34,046	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 82501 - Forklift / Pallet Jack

Placement Band - 1974 - 2020 Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 82501 - Forklift / Pallet Jack

Placement Band - 1974 - 2020   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

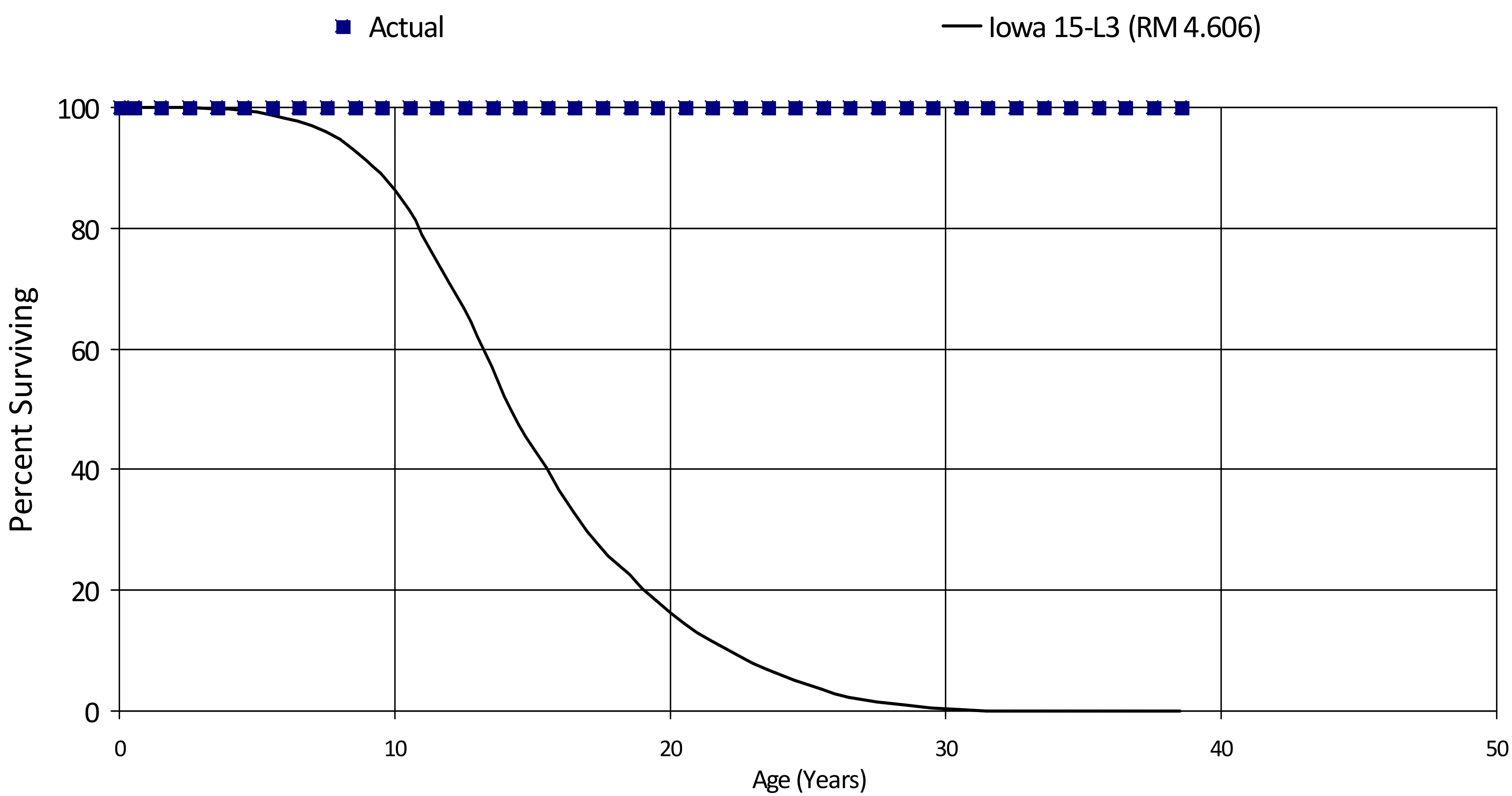
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	10,775,590	0	0.00000	1.00000	100.00
0.5	10,618,412	0	0.00000	1.00000	100.00
1.5	10,422,356	0	0.00000	1.00000	100.00
2.5	8,594,962	0	0.00000	1.00000	100.00
3.5	7,704,765	0	0.00000	1.00000	100.00
4.5	5,436,706	0	0.00000	1.00000	100.00
5.5	4,663,420	0	0.00000	1.00000	100.00
6.5	3,231,740	0	0.00000	1.00000	100.00
7.5	2,955,933	0	0.00000	1.00000	100.00
8.5	1,908,969	0	0.00000	1.00000	100.00
9.5	1,908,969	0	0.00000	1.00000	100.00
10.5	1,454,306	0	0.00000	1.00000	100.00
11.5	1,194,576	0	0.00000	1.00000	100.00
12.5	855,056	0	0.00000	1.00000	100.00
13.5	476,760	0	0.00000	1.00000	100.00
14.5	476,760	0	0.00000	1.00000	100.00
15.5	396,554	0	0.00000	1.00000	100.00
16.5	361,192	0	0.00000	1.00000	100.00
17.5	336,273	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 82502 - Snow Vehicle

Placement Band - 1972 - 2019   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 82502 - Snow Vehicle

Placement Band - 1972 - 2019 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,349,657	0	0.00000	1.00000	100.00
0.5	2,349,657	0	0.00000	1.00000	100.00
1.5	2,120,132	0	0.00000	1.00000	100.00
2.5	2,044,701	0	0.00000	1.00000	100.00
3.5	1,960,715	0	0.00000	1.00000	100.00
4.5	1,709,120	0	0.00000	1.00000	100.00
5.5	1,478,253	0	0.00000	1.00000	100.00
6.5	1,398,256	0	0.00000	1.00000	100.00
7.5	1,283,744	0	0.00000	1.00000	100.00
8.5	898,581	0	0.00000	1.00000	100.00
9.5	846,921	0	0.00000	1.00000	100.00
10.5	846,921	0	0.00000	1.00000	100.00
11.5	825,185	0	0.00000	1.00000	100.00
12.5	574,533	0	0.00000	1.00000	100.00
13.5	558,630	0	0.00000	1.00000	100.00
14.5	558,630	0	0.00000	1.00000	100.00
15.5	558,630	0	0.00000	1.00000	100.00
16.5	538,428	0	0.00000	1.00000	100.00
17.5	538,428	0	0.00000	1.00000	100.00
18.5	538,428	0	0.00000	1.00000	100.00
19.5	528,528	0	0.00000	1.00000	100.00
20.5	521,453	0	0.00000	1.00000	100.00
21.5	517,691	0	0.00000	1.00000	100.00
22.5	451,783	0	0.00000	1.00000	100.00
23.5	451,783	0	0.00000	1.00000	100.00
24.5	451,783	0	0.00000	1.00000	100.00
25.5	371,359	0	0.00000	1.00000	100.00
26.5	227,316	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 82502 - Snow Vehicle

Placement Band - 1972 - 2019 Experience Band - 2020 - 2020

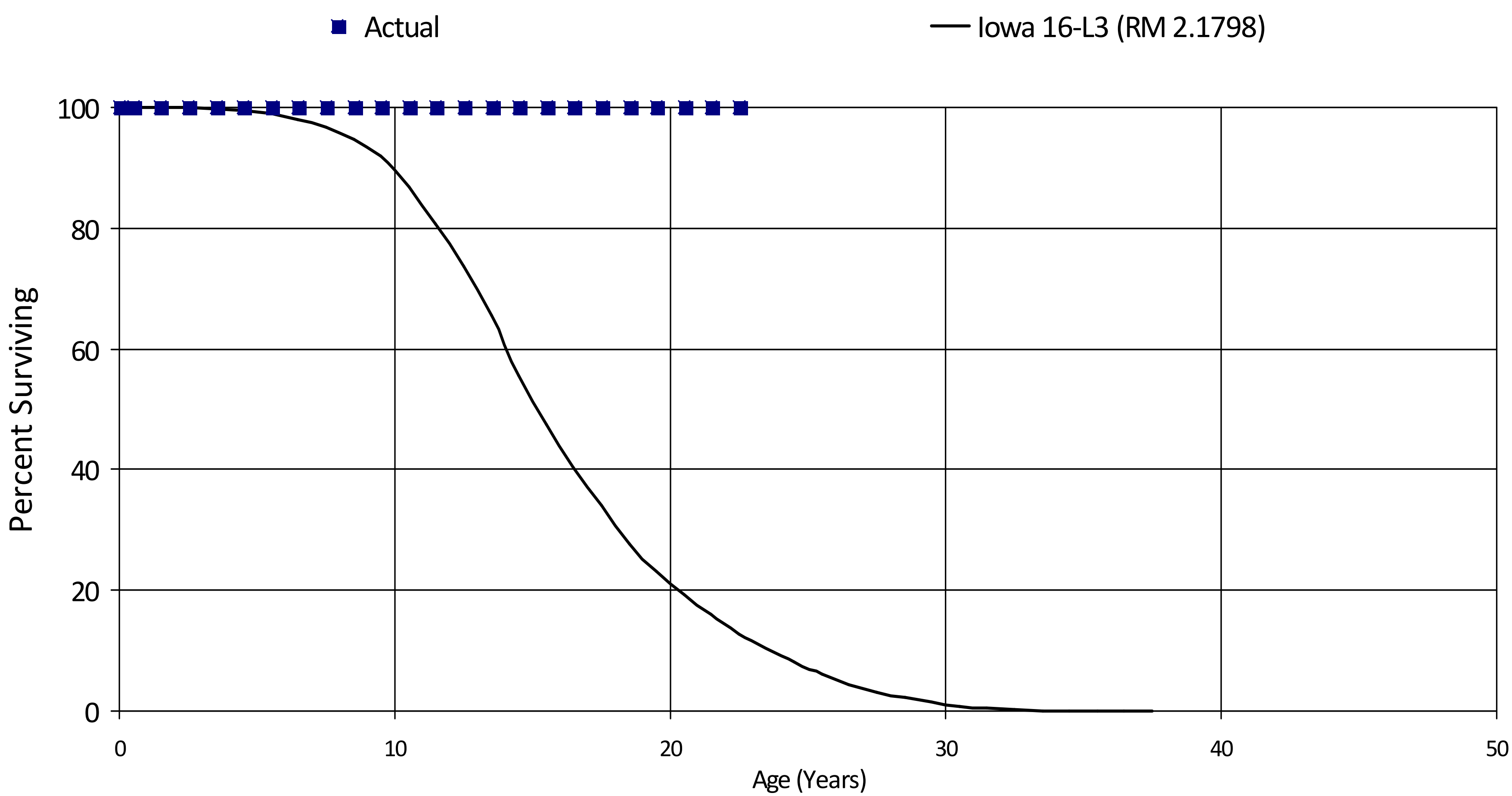
27.5	227,316	0	0.00000	1.00000	100.00
28.5	188,949	0	0.00000	1.00000	100.00
29.5	74,662	0	0.00000	1.00000	100.00
30.5	40,275	0	0.00000	1.00000	100.00
31.5	40,275	0	0.00000	1.00000	100.00
32.5	40,275	0	0.00000	1.00000	100.00
33.5	40,275	0	0.00000	1.00000	100.00
34.5	40,275	0	0.00000	1.00000	100.00
35.5	40,275	0	0.00000	1.00000	100.00
36.5	40,275	0	0.00000	1.00000	100.00
37.5	40,275	0	0.00000	1.00000	100.00
38.5	40,275	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 82503 - Sweeper

Placement Band - 1997 - 2017 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 82503 - Sweeper

Placement Band - 1997 - 2017   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

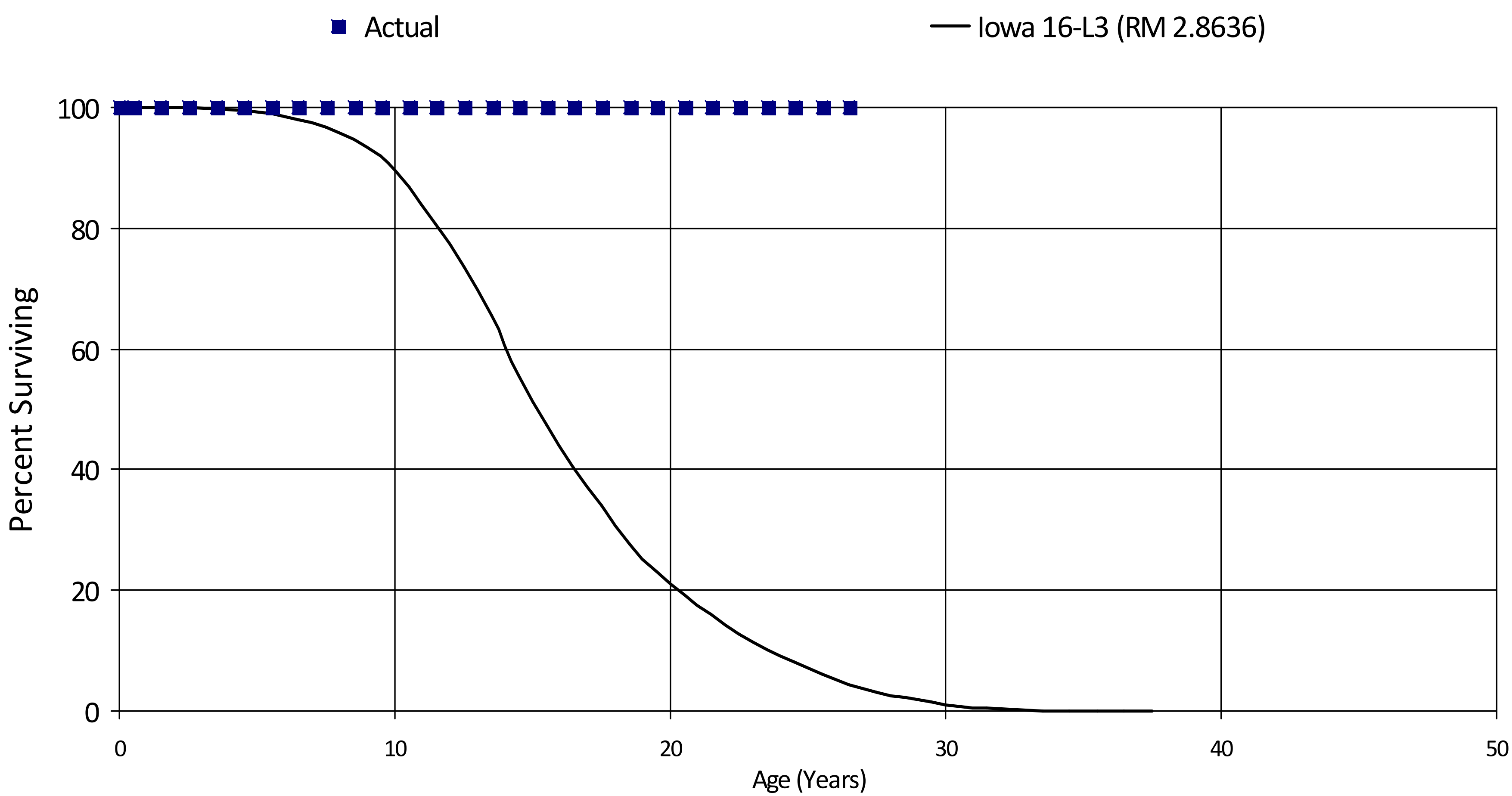
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	40,101	0	0.00000	1.00000	100.00
0.5	40,101	0	0.00000	1.00000	100.00
1.5	40,101	0	0.00000	1.00000	100.00
2.5	40,101	0	0.00000	1.00000	100.00
3.5	23,035	0	0.00000	1.00000	100.00
4.5	23,035	0	0.00000	1.00000	100.00
5.5	23,035	0	0.00000	1.00000	100.00
6.5	23,035	0	0.00000	1.00000	100.00
7.5	23,035	0	0.00000	1.00000	100.00
8.5	23,035	0	0.00000	1.00000	100.00
9.5	23,035	0	0.00000	1.00000	100.00
10.5	23,035	0	0.00000	1.00000	100.00
11.5	23,035	0	0.00000	1.00000	100.00
12.5	23,035	0	0.00000	1.00000	100.00
13.5	16,884	0	0.00000	1.00000	100.00
14.5	16,884	0	0.00000	1.00000	100.00
15.5	16,884	0	0.00000	1.00000	100.00
16.5	16,884	0	0.00000	1.00000	100.00
17.5	12,708	0	0.00000	1.00000	100.00
18.5	12,708	0	0.00000	1.00000	100.00
19.5	12,708	0	0.00000	1.00000	100.00
20.5	12,708	0	0.00000	1.00000	100.00
21.5	4,588	0	0.00000	1.00000	100.00
22.5	4,588	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 82504 - Loader / Backhoe

Placement Band - 1976 - 2019 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 82504 - Loader / Backhoe

Placement Band - 1976 - 2019 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,149,846	0	0.00000	1.00000	100.00
0.5	2,149,846	0	0.00000	1.00000	100.00
1.5	1,807,888	0	0.00000	1.00000	100.00
2.5	1,706,112	0	0.00000	1.00000	100.00
3.5	1,163,373	0	0.00000	1.00000	100.00
4.5	822,664	0	0.00000	1.00000	100.00
5.5	727,449	0	0.00000	1.00000	100.00
6.5	687,639	0	0.00000	1.00000	100.00
7.5	531,957	0	0.00000	1.00000	100.00
8.5	483,244	0	0.00000	1.00000	100.00
9.5	400,645	0	0.00000	1.00000	100.00
10.5	353,693	0	0.00000	1.00000	100.00
11.5	353,693	0	0.00000	1.00000	100.00
12.5	334,074	0	0.00000	1.00000	100.00
13.5	312,516	0	0.00000	1.00000	100.00
14.5	294,207	0	0.00000	1.00000	100.00
15.5	294,207	0	0.00000	1.00000	100.00
16.5	275,603	0	0.00000	1.00000	100.00
17.5	275,603	0	0.00000	1.00000	100.00
18.5	214,652	0	0.00000	1.00000	100.00
19.5	214,652	0	0.00000	1.00000	100.00
20.5	214,652	0	0.00000	1.00000	100.00
21.5	91,073	0	0.00000	1.00000	100.00
22.5	91,073	0	0.00000	1.00000	100.00
23.5	57,679	0	0.00000	1.00000	100.00
24.5	57,679	0	0.00000	1.00000	100.00
25.5	57,679	0	0.00000	1.00000	100.00
26.5	57,679	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 82504 - Loader / Backhoe

Placement Band - 1976 - 2019   Experience Band - 2020 - 2020

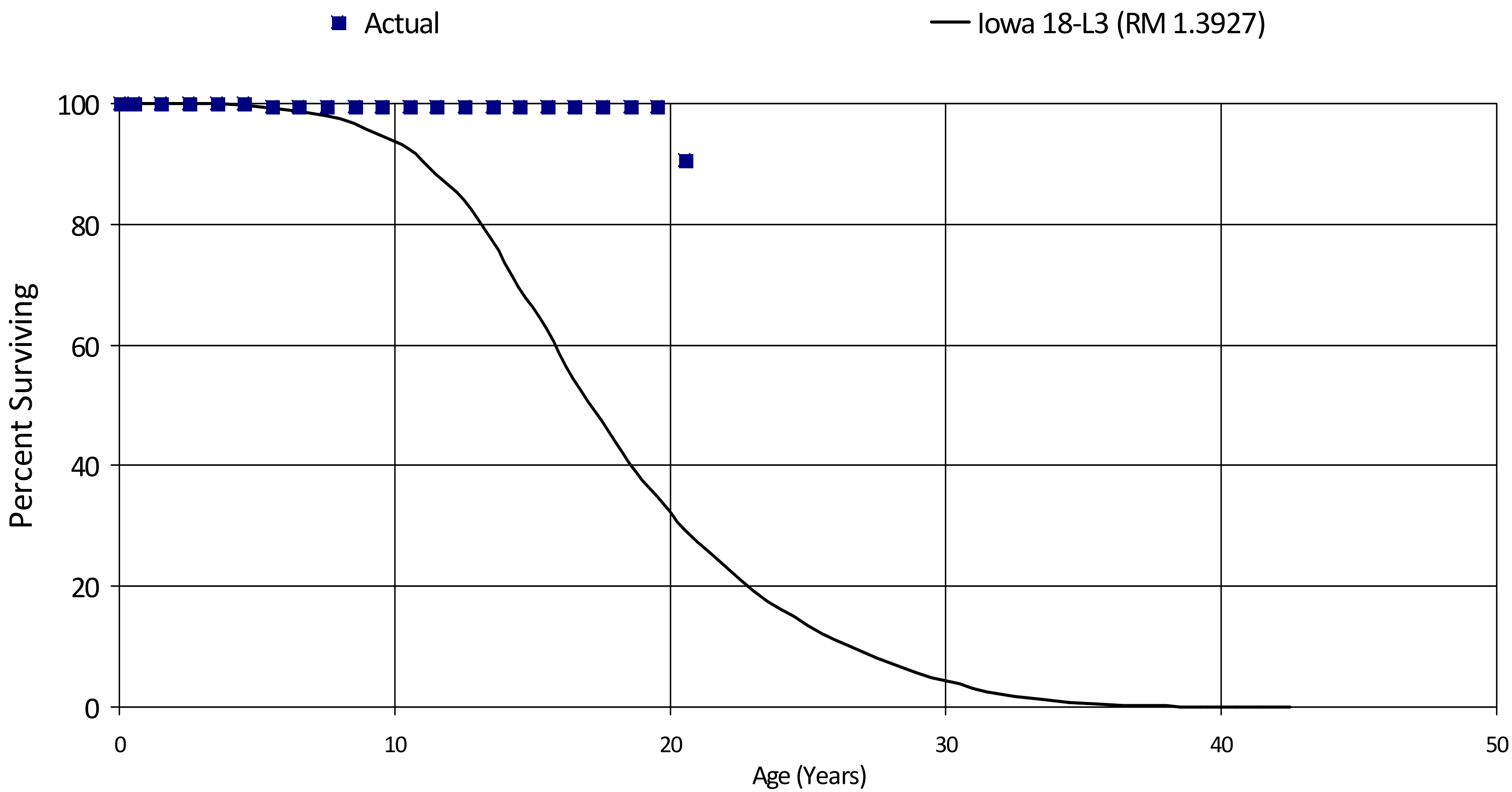
Totals:	0

BC Hydro Power Authority

Account 82505 - Trailer, Reel / Pole / Utility

Placement Band - 1968 - 2020   Experience Band - 2011 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 82505 - Trailer, Reel / Pole / Utility

Placement Band - 1968 - 2020   Experience Band - 2011 - 2020

RETIREMENT RATE ANALYSIS

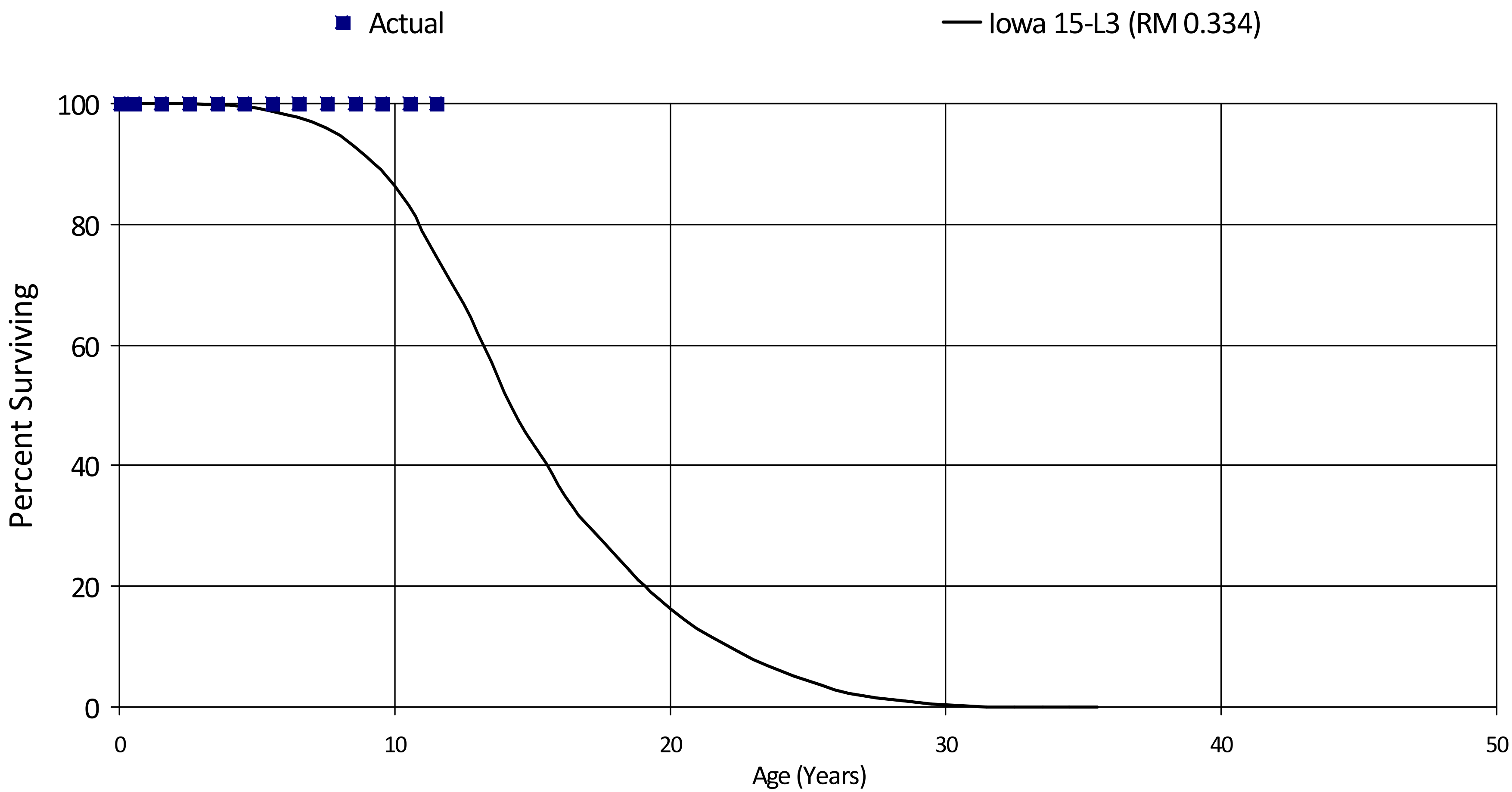
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	16,174,175	0	0.00000	1.00000	100.00
0.5	15,950,404	0	0.00000	1.00000	100.00
1.5	14,580,490	0	0.00000	1.00000	100.00
2.5	12,772,907	0	0.00000	1.00000	100.00
3.5	11,104,187	0	0.00000	1.00000	100.00
4.5	9,018,017	41,442	0.00460	0.99540	100.00
5.5	7,866,865	0	0.00000	1.00000	99.54
6.5	4,681,857	0	0.00000	1.00000	99.54
7.5	3,765,130	0	0.00000	1.00000	99.54
8.5	2,961,193	0	0.00000	1.00000	99.54
9.5	2,104,702	0	0.00000	1.00000	99.54
10.5	1,933,034	0	0.00000	1.00000	99.54
11.5	1,136,979	0	0.00000	1.00000	99.54
12.5	818,543	0	0.00000	1.00000	99.54
13.5	640,435	0	0.00000	1.00000	99.54
14.5	627,408	0	0.00000	1.00000	99.54
15.5	600,268	0	0.00000	1.00000	99.54
16.5	431,678	0	0.00000	1.00000	99.54
17.5	252,974	0	0.00000	1.00000	99.54
18.5	246,270	0	0.00000	1.00000	99.54
19.5	195,537	17,574	0.08988	0.91012	99.54
20.5	175,539	0	0.00000	1.00000	90.59
	Totals:	59,016			

BC Hydro Power Authority

Account 82506 - Welder, Mobile, Self-Powered

Placement Band - 2003 - 2019 Experience Band - 2014 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 82506 - Welder, Mobile, Self-Powered

Placement Band - 2003 - 2019   Experience Band - 2014 - 2020

RETIREMENT RATE ANALYSIS

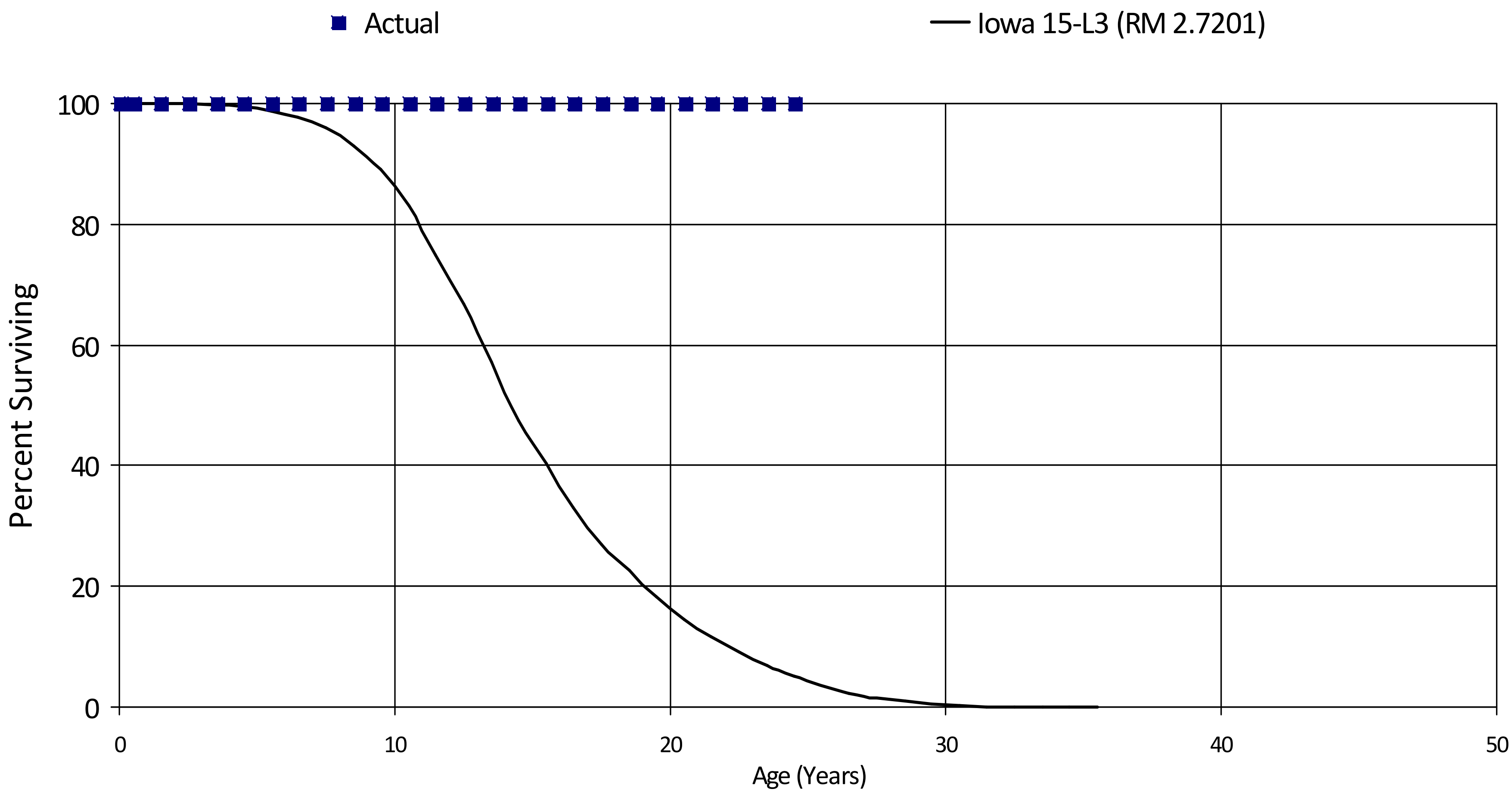
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	103,854	0	0.00000	1.00000	100.00
0.5	103,854	0	0.00000	1.00000	100.00
1.5	89,895	0	0.00000	1.00000	100.00
2.5	89,895	0	0.00000	1.00000	100.00
3.5	82,937	0	0.00000	1.00000	100.00
4.5	82,937	0	0.00000	1.00000	100.00
5.5	73,785	0	0.00000	1.00000	100.00
6.5	73,785	0	0.00000	1.00000	100.00
7.5	73,785	0	0.00000	1.00000	100.00
8.5	73,785	0	0.00000	1.00000	100.00
9.5	37,556	0	0.00000	1.00000	100.00
10.5	14,406	0	0.00000	1.00000	100.00
11.5	2,353	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 82507 - Compressor, Mobile, Self-Powered

Placement Band - 1995 - 2017   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 82507 - Compressor, Mobile, Self-Powered

Placement Band - 1995 - 2017 Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

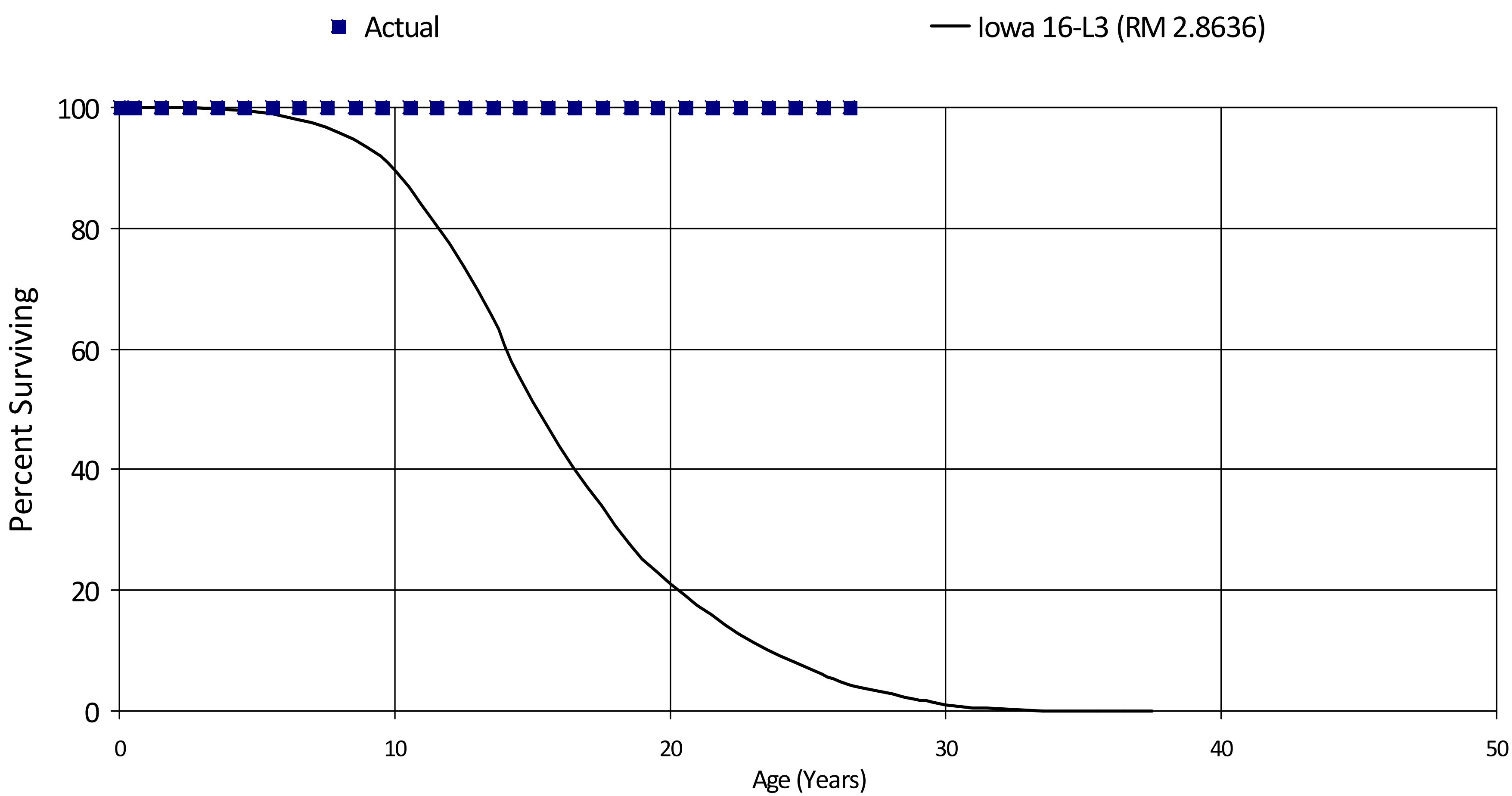
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	32,147	0	0.00000	1.00000	100.00
0.5	32,147	0	0.00000	1.00000	100.00
1.5	32,147	0	0.00000	1.00000	100.00
2.5	32,147	0	0.00000	1.00000	100.00
3.5	19,584	0	0.00000	1.00000	100.00
4.5	19,584	0	0.00000	1.00000	100.00
5.5	19,584	0	0.00000	1.00000	100.00
6.5	19,584	0	0.00000	1.00000	100.00
7.5	19,584	0	0.00000	1.00000	100.00
8.5	19,584	0	0.00000	1.00000	100.00
9.5	19,584	0	0.00000	1.00000	100.00
10.5	19,584	0	0.00000	1.00000	100.00
11.5	10,571	0	0.00000	1.00000	100.00
12.5	10,571	0	0.00000	1.00000	100.00
13.5	10,571	0	0.00000	1.00000	100.00
14.5	10,571	0	0.00000	1.00000	100.00
15.5	10,571	0	0.00000	1.00000	100.00
16.5	10,571	0	0.00000	1.00000	100.00
17.5	10,571	0	0.00000	1.00000	100.00
18.5	10,571	0	0.00000	1.00000	100.00
19.5	10,571	0	0.00000	1.00000	100.00
20.5	6,213	0	0.00000	1.00000	100.00
21.5	4,357	0	0.00000	1.00000	100.00
22.5	4,357	0	0.00000	1.00000	100.00
23.5	3,294	0	0.00000	1.00000	100.00
24.5	3,294	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 82508 - Chipper

Placement Band - 1993 - 2018   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 82508 - Chipper

Placement Band - 1993 - 2018   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	44,270	0	0.00000	1.00000	100.00
0.5	44,270	0	0.00000	1.00000	100.00
1.5	44,270	0	0.00000	1.00000	100.00
2.5	3,911	0	0.00000	1.00000	100.00
3.5	3,911	0	0.00000	1.00000	100.00
4.5	3,911	0	0.00000	1.00000	100.00
5.5	3,911	0	0.00000	1.00000	100.00
6.5	3,911	0	0.00000	1.00000	100.00
7.5	3,911	0	0.00000	1.00000	100.00
8.5	3,911	0	0.00000	1.00000	100.00
9.5	3,911	0	0.00000	1.00000	100.00
10.5	3,911	0	0.00000	1.00000	100.00
11.5	3,911	0	0.00000	1.00000	100.00
12.5	3,911	0	0.00000	1.00000	100.00
13.5	3,911	0	0.00000	1.00000	100.00
14.5	3,911	0	0.00000	1.00000	100.00
15.5	3,911	0	0.00000	1.00000	100.00
16.5	3,911	0	0.00000	1.00000	100.00
17.5	3,911	0	0.00000	1.00000	100.00
18.5	3,911	0	0.00000	1.00000	100.00
19.5	3,911	0	0.00000	1.00000	100.00
20.5	3,911	0	0.00000	1.00000	100.00
21.5	3,911	0	0.00000	1.00000	100.00
22.5	3,911	0	0.00000	1.00000	100.00
23.5	3,911	0	0.00000	1.00000	100.00
24.5	3,911	0	0.00000	1.00000	100.00
25.5	3,911	0	0.00000	1.00000	100.00
26.5	3,911	0	0.00000	1.00000	100.00

BC Hydro Power Authority

Account 82508 - Chipper

Placement Band - 1993 - 2018   Experience Band - 2020 - 2020

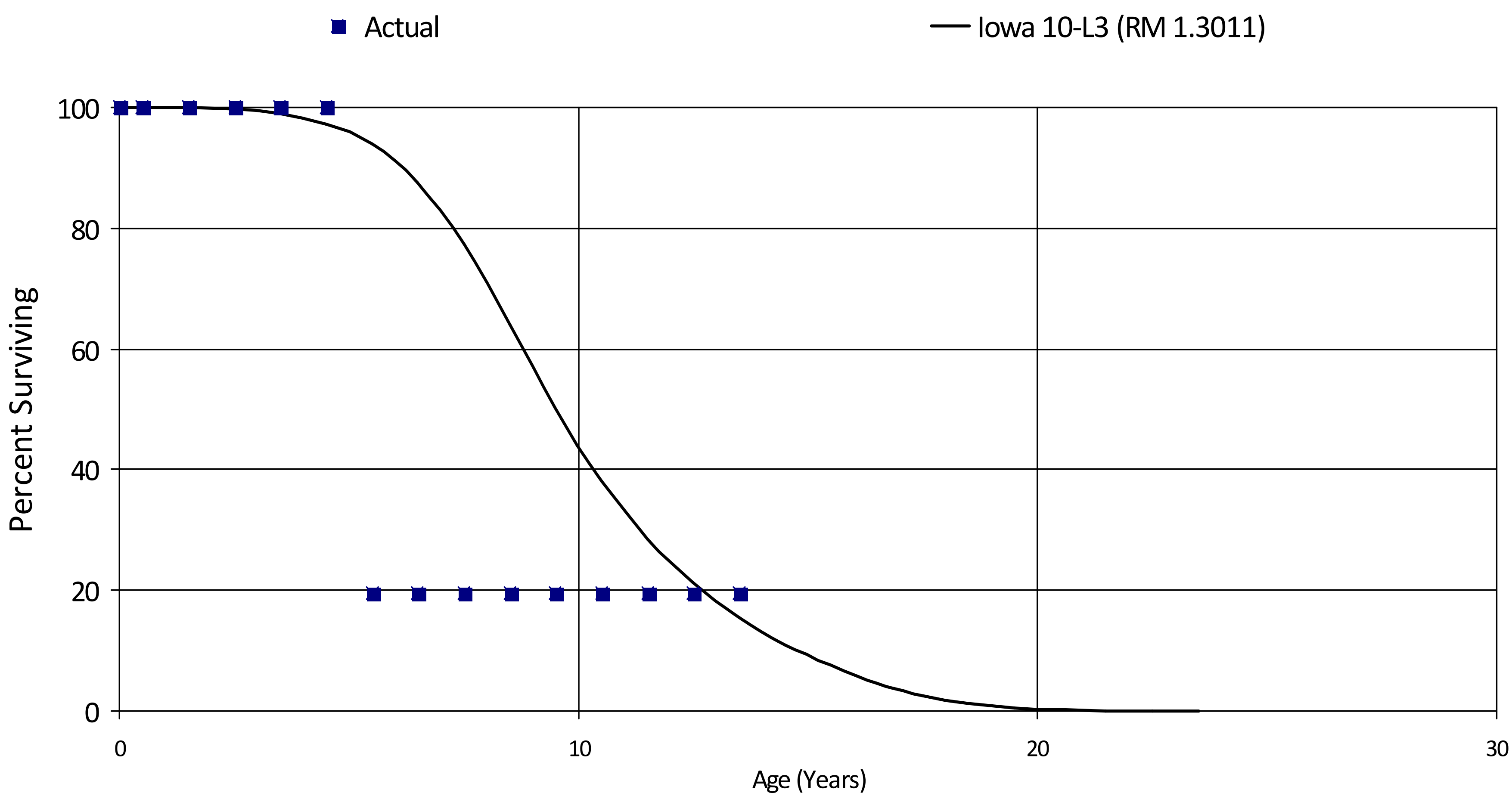
Totals:	0

BC Hydro Power Authority

Account 82509 - Tractor

Placement Band - 2005 - 2019   Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 82509 - Tractor

Placement Band - 2005 - 2019   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

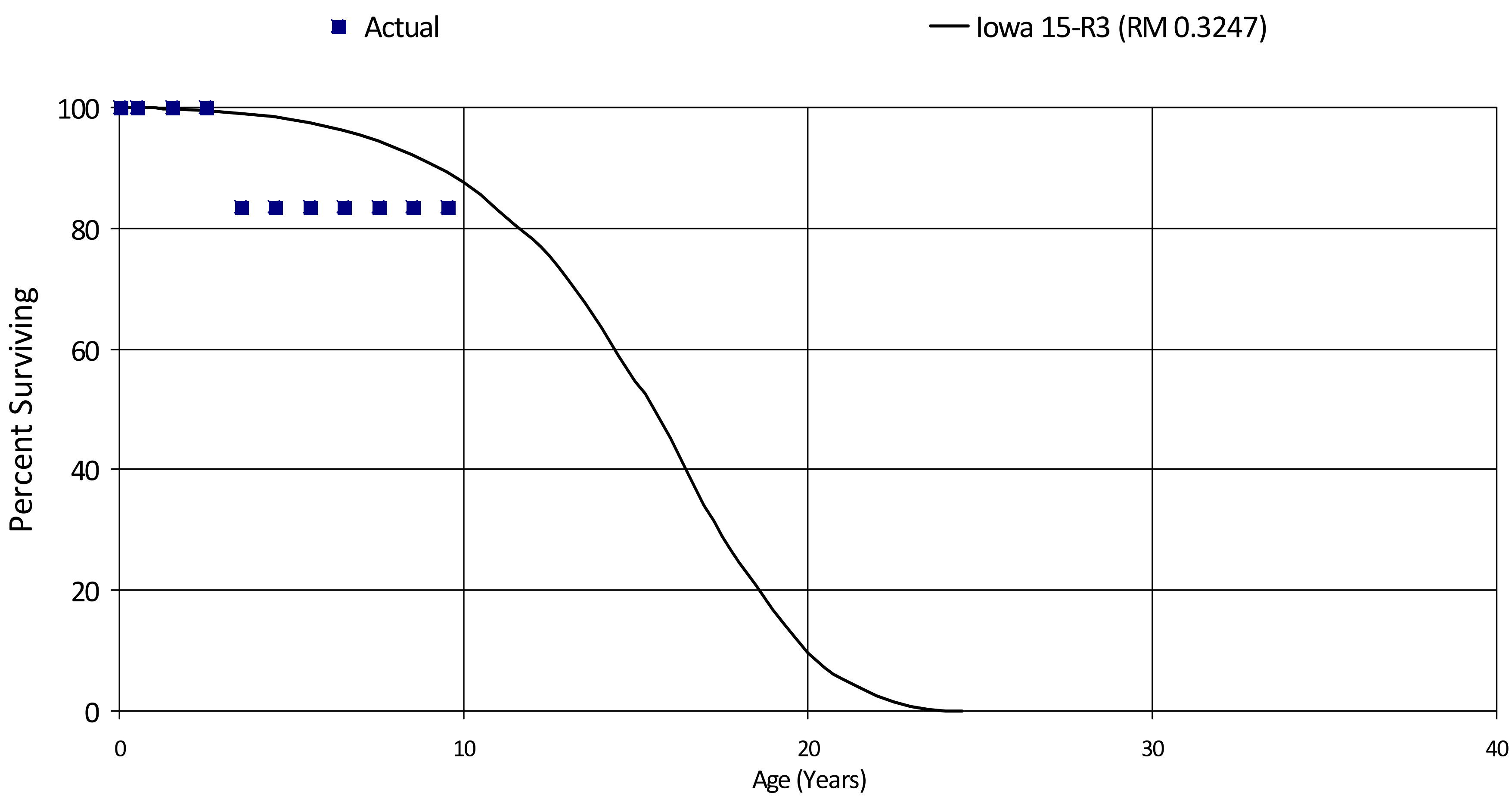
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	929,271	0	0.00000	1.00000	100.00
0.5	929,271	0	0.00000	1.00000	100.00
1.5	854,437	0	0.00000	1.00000	100.00
2.5	854,437	0	0.00000	1.00000	100.00
3.5	854,437	0	0.00000	1.00000	100.00
4.5	806,055	649,394	0.80564	0.19436	100.00
5.5	141,006	0	0.00000	1.00000	19.44
6.5	141,006	0	0.00000	1.00000	19.44
7.5	141,006	0	0.00000	1.00000	19.44
8.5	141,006	0	0.00000	1.00000	19.44
9.5	78,333	0	0.00000	1.00000	19.44
10.5	78,333	0	0.00000	1.00000	19.44
11.5	78,333	0	0.00000	1.00000	19.44
12.5	78,333	0	0.00000	1.00000	19.44
13.5	78,333	0	0.00000	1.00000	19.44
	Totals:	649,394			

BC Hydro Power Authority

Account 82512 - Regen Plan, Xformer Oil

Placement Band - 1994 - 2016 Experience Band - 2015 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 82512 - Regen Plan, Xformer Oil

Placement Band - 1994 - 2016   Experience Band - 2015 - 2020

RETIREMENT RATE ANALYSIS

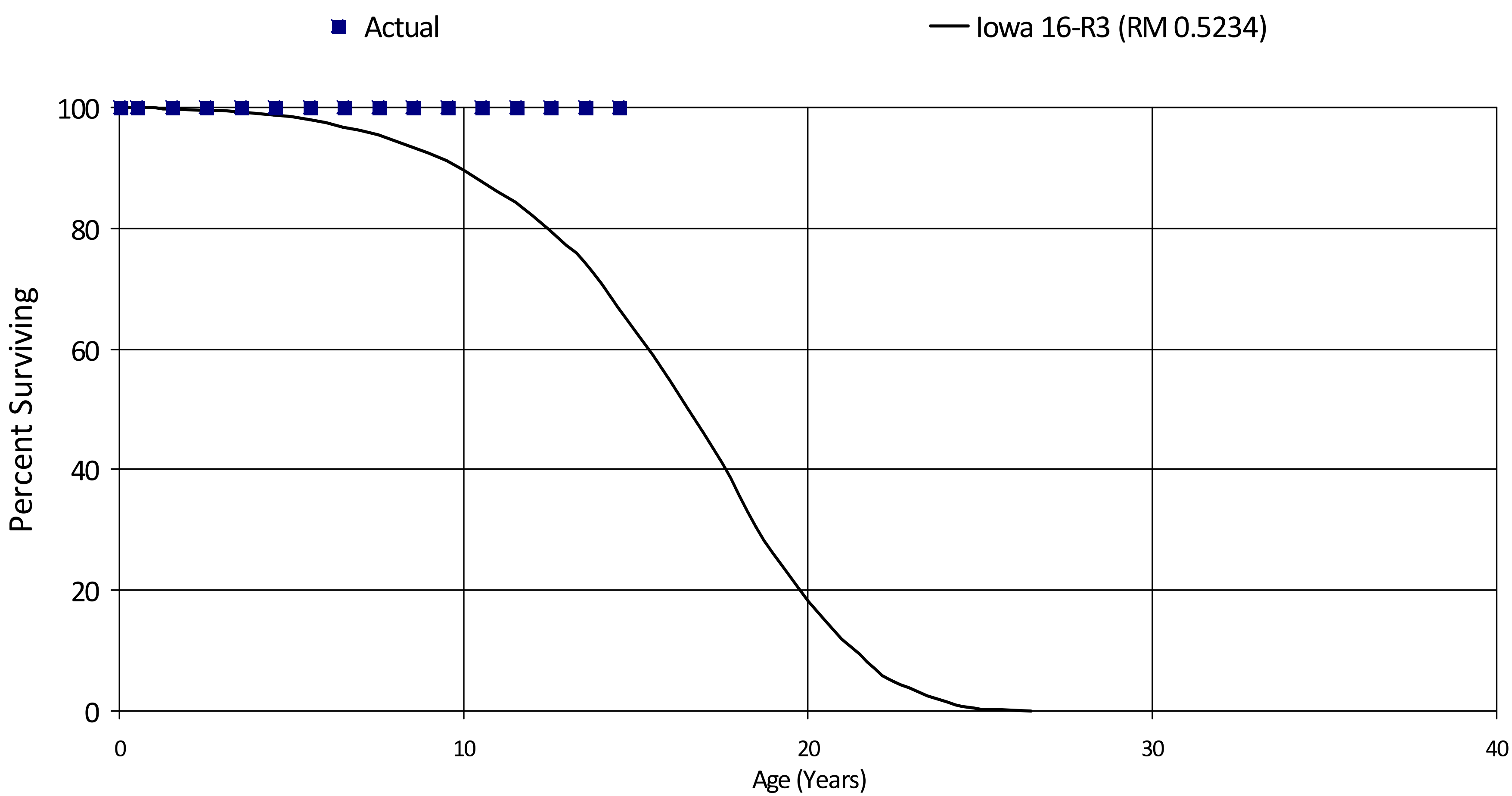
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	3,799,892	0	0.00000	1.00000	100.00
0.5	3,799,892	0	0.00000	1.00000	100.00
1.5	3,799,892	0	0.00000	1.00000	100.00
2.5	3,799,892	627,861	0.16523	0.83477	100.00
3.5	3,172,031	0	0.00000	1.00000	83.48
4.5	994,972	0	0.00000	1.00000	83.48
5.5	994,972	0	0.00000	1.00000	83.48
6.5	994,972	0	0.00000	1.00000	83.48
7.5	994,972	0	0.00000	1.00000	83.48
8.5	122,943	0	0.00000	1.00000	83.48
9.5	122,943	0	0.00000	1.00000	83.48
	Totals:	627,861			

BC Hydro Power Authority

Account 82513 - Manlift

Placement Band - 1997 - 2019 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 82513 - Manlift

Placement Band - 1997 - 2019   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

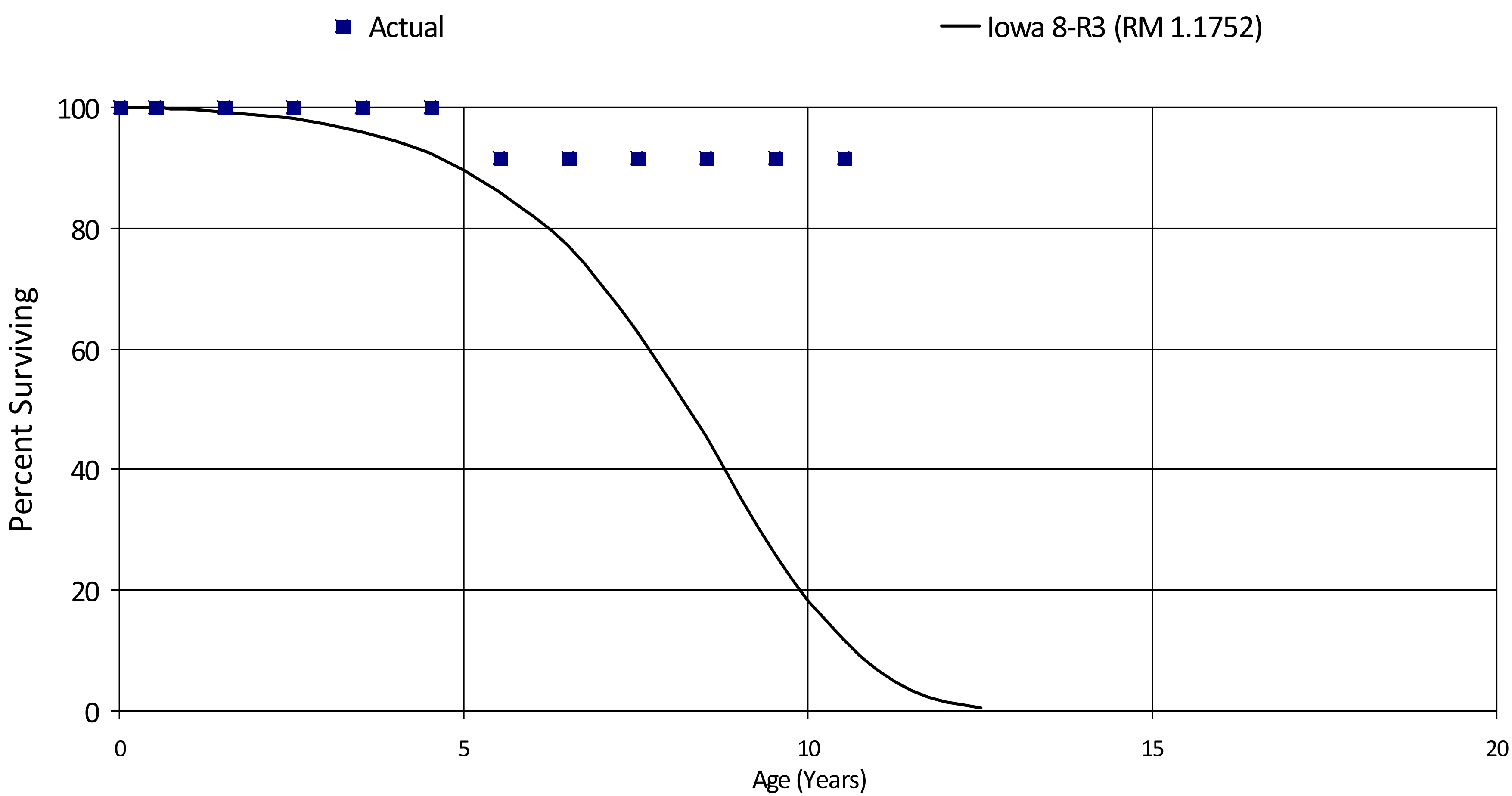
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	517,172	0	0.00000	1.00000	100.00
0.5	517,172	0	0.00000	1.00000	100.00
1.5	351,165	0	0.00000	1.00000	100.00
2.5	234,045	0	0.00000	1.00000	100.00
3.5	234,045	0	0.00000	1.00000	100.00
4.5	234,045	0	0.00000	1.00000	100.00
5.5	216,642	0	0.00000	1.00000	100.00
6.5	216,642	0	0.00000	1.00000	100.00
7.5	216,642	0	0.00000	1.00000	100.00
8.5	152,466	0	0.00000	1.00000	100.00
9.5	152,466	0	0.00000	1.00000	100.00
10.5	148,478	0	0.00000	1.00000	100.00
11.5	115,869	0	0.00000	1.00000	100.00
12.5	115,869	0	0.00000	1.00000	100.00
13.5	115,869	0	0.00000	1.00000	100.00
14.5	12,664	0	0.00000	1.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 82514 - All Terrain Vehicle

Placement Band - 1995 - 2020   Experience Band - 2017 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 82514 - All Terrain Vehicle

Placement Band - 1995 - 2020   Experience Band - 2017 - 2020

RETIREMENT RATE ANALYSIS

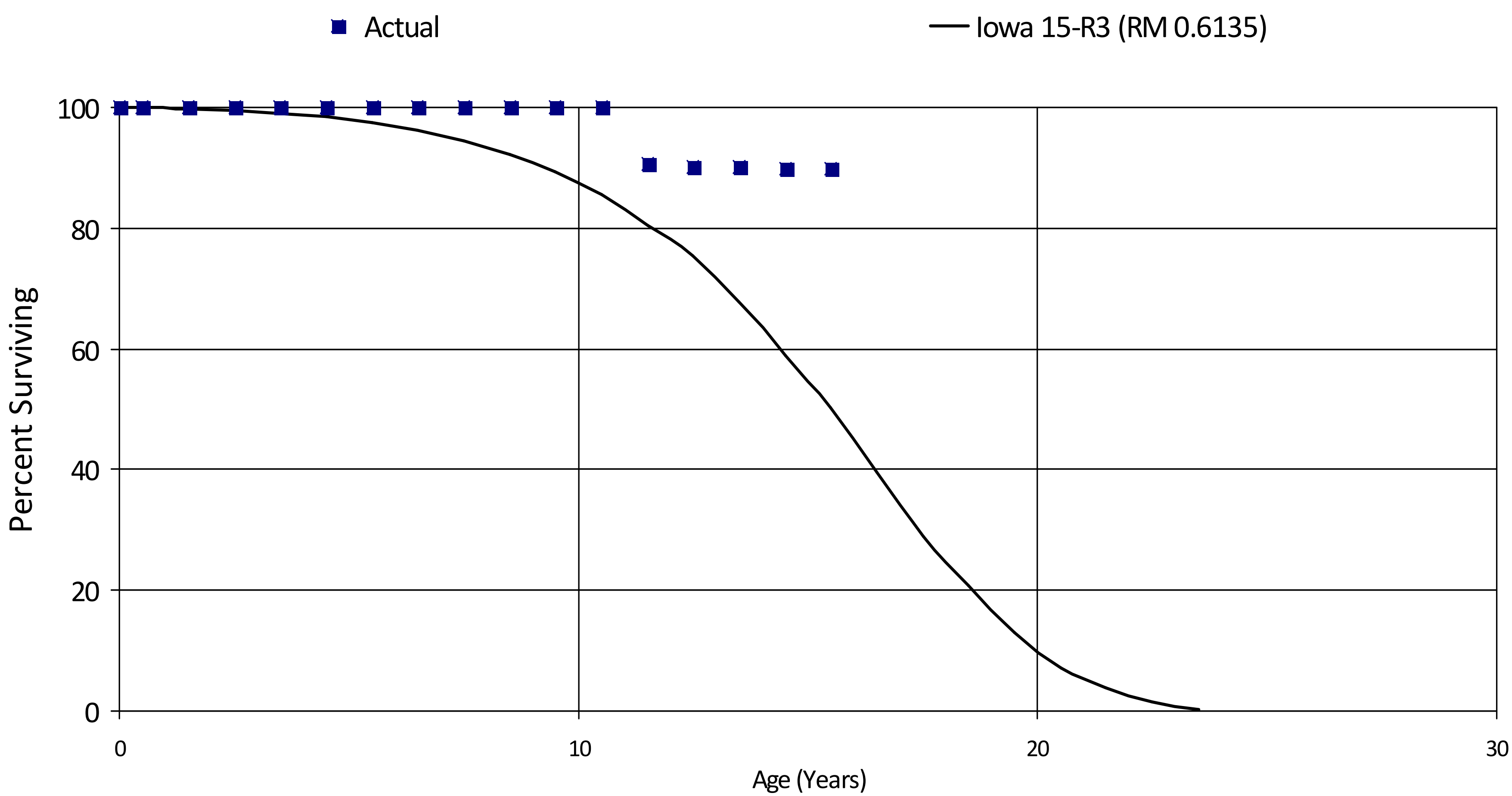
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,018,417	0	0.00000	1.00000	100.00
0.5	1,984,104	0	0.00000	1.00000	100.00
1.5	1,703,158	0	0.00000	1.00000	100.00
2.5	1,352,335	0	0.00000	1.00000	100.00
3.5	985,033	0	0.00000	1.00000	100.00
4.5	781,651	66,477	0.08505	0.91495	100.00
5.5	417,226	0	0.00000	1.00000	91.50
6.5	298,245	0	0.00000	1.00000	91.50
7.5	262,583	0	0.00000	1.00000	91.50
8.5	224,051	0	0.00000	1.00000	91.50
9.5	53,208	0	0.00000	1.00000	91.50
10.5	48,187	0	0.00000	1.00000	91.50
	Totals:	66,477			

BC Hydro Power Authority

Account 82601 - Test / Calibration Equipment

Placement Band - 1996 - 2019   Experience Band - 2018 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 82601 - Test / Calibration Equipment

Placement Band - 1996 - 2019 Experience Band - 2018 - 2020

RETIREMENT RATE ANALYSIS

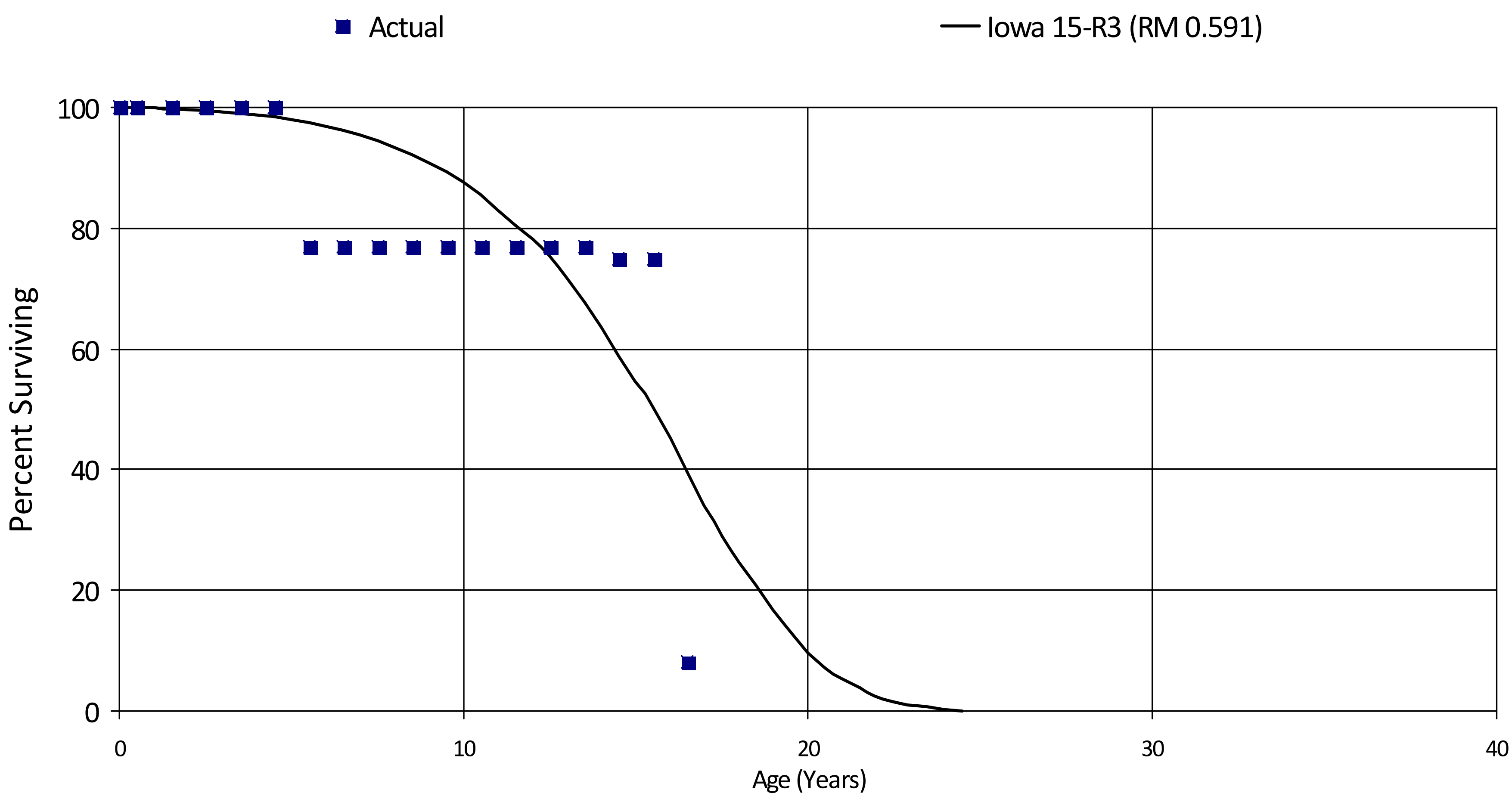
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	13,009,672	0	0.00000	1.00000	100.00
0.5	13,009,672	0	0.00000	1.00000	100.00
1.5	10,345,854	0	0.00000	1.00000	100.00
2.5	9,064,425	0	0.00000	1.00000	100.00
3.5	5,866,576	0	0.00000	1.00000	100.00
4.5	4,828,022	0	0.00000	1.00000	100.00
5.5	4,579,127	0	0.00000	1.00000	100.00
6.5	3,629,548	0	0.00000	1.00000	100.00
7.5	2,589,139	0	0.00000	1.00000	100.00
8.5	2,261,097	0	0.00000	1.00000	100.00
9.5	647,505	0	0.00000	1.00000	100.00
10.5	647,505	61,083	0.09434	0.90566	100.00
11.5	465,862	2,416	0.00519	0.99481	90.57
12.5	289,565	0	0.00000	1.00000	90.10
13.5	289,565	996	0.00344	0.99656	90.10
14.5	226,014	0	0.00000	1.00000	89.79
15.5	134,083	0	0.00000	1.00000	89.79
	Totals:	64,495			

BC Hydro Power Authority

Account 82603 - Manufacturing / Test Equipment

Placement Band - 1997 - 2018   Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 82603 - Manufacturing / Test Equipment

Placement Band - 1997 - 2018   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

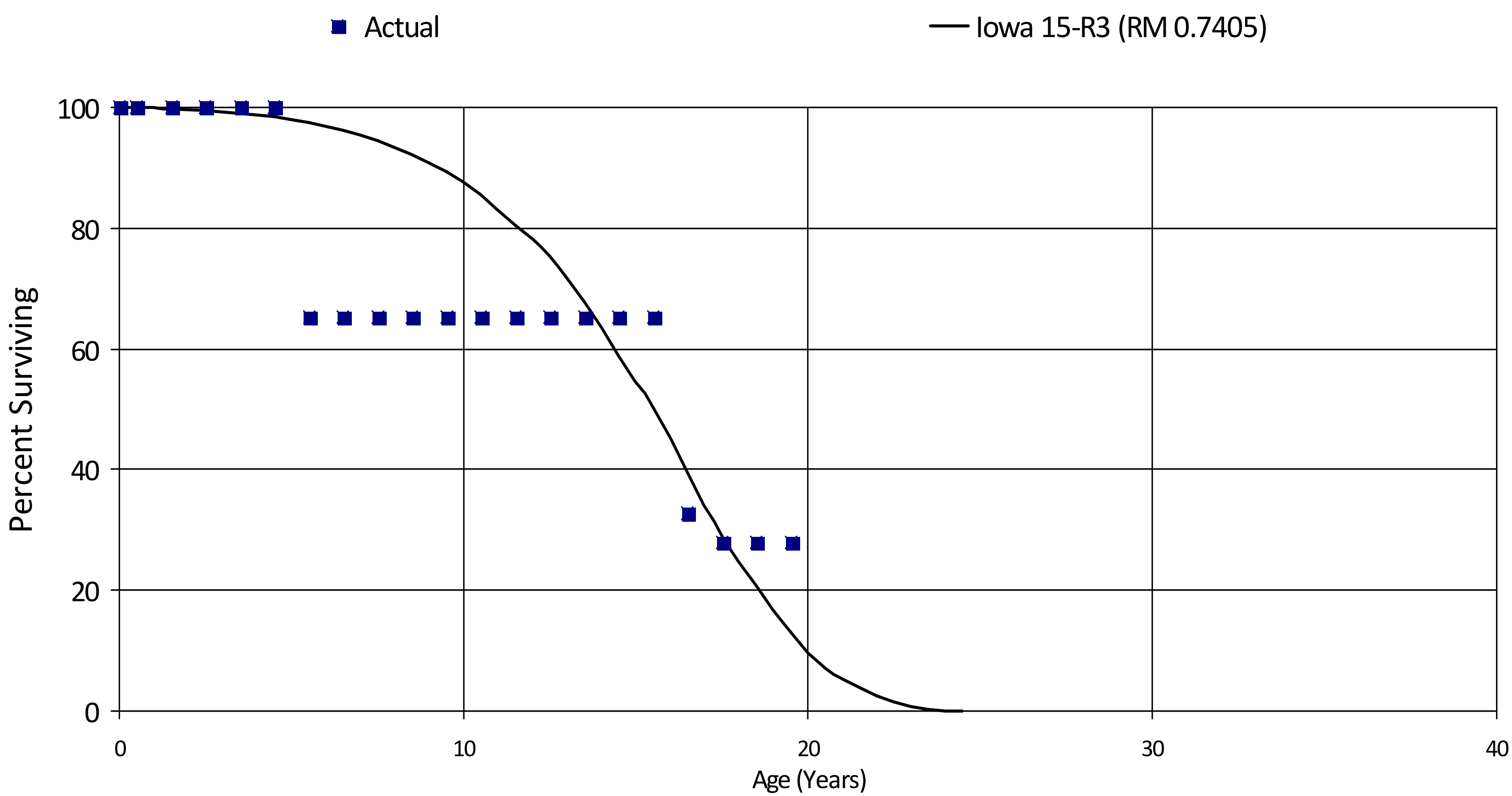
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	861,413	0	0.00000	1.00000	100.00
0.5	861,413	0	0.00000	1.00000	100.00
1.5	861,413	0	0.00000	1.00000	100.00
2.5	856,006	0	0.00000	1.00000	100.00
3.5	844,548	0	0.00000	1.00000	100.00
4.5	691,162	158,927	0.22994	0.77006	100.00
5.5	532,235	0	0.00000	1.00000	77.01
6.5	532,235	0	0.00000	1.00000	77.01
7.5	532,235	0	0.00000	1.00000	77.01
8.5	493,444	0	0.00000	1.00000	77.01
9.5	427,270	0	0.00000	1.00000	77.01
10.5	421,732	0	0.00000	1.00000	77.01
11.5	421,732	0	0.00000	1.00000	77.01
12.5	421,732	0	0.00000	1.00000	77.01
13.5	395,274	10,970	0.02775	0.97225	77.01
14.5	368,017	0	0.00000	1.00000	74.87
15.5	363,082	323,511	0.89101	0.10899	74.87
16.5	34,566	34,566	1.00000		8.16
	Totals:	527,974			

BC Hydro Power Authority

Account 83001 - Boat

Placement Band - 1993 - 2019 Experience Band - 2012 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 83001 - Boat

Placement Band - 1993 - 2019   Experience Band - 2012 - 2020

RETIREMENT RATE ANALYSIS

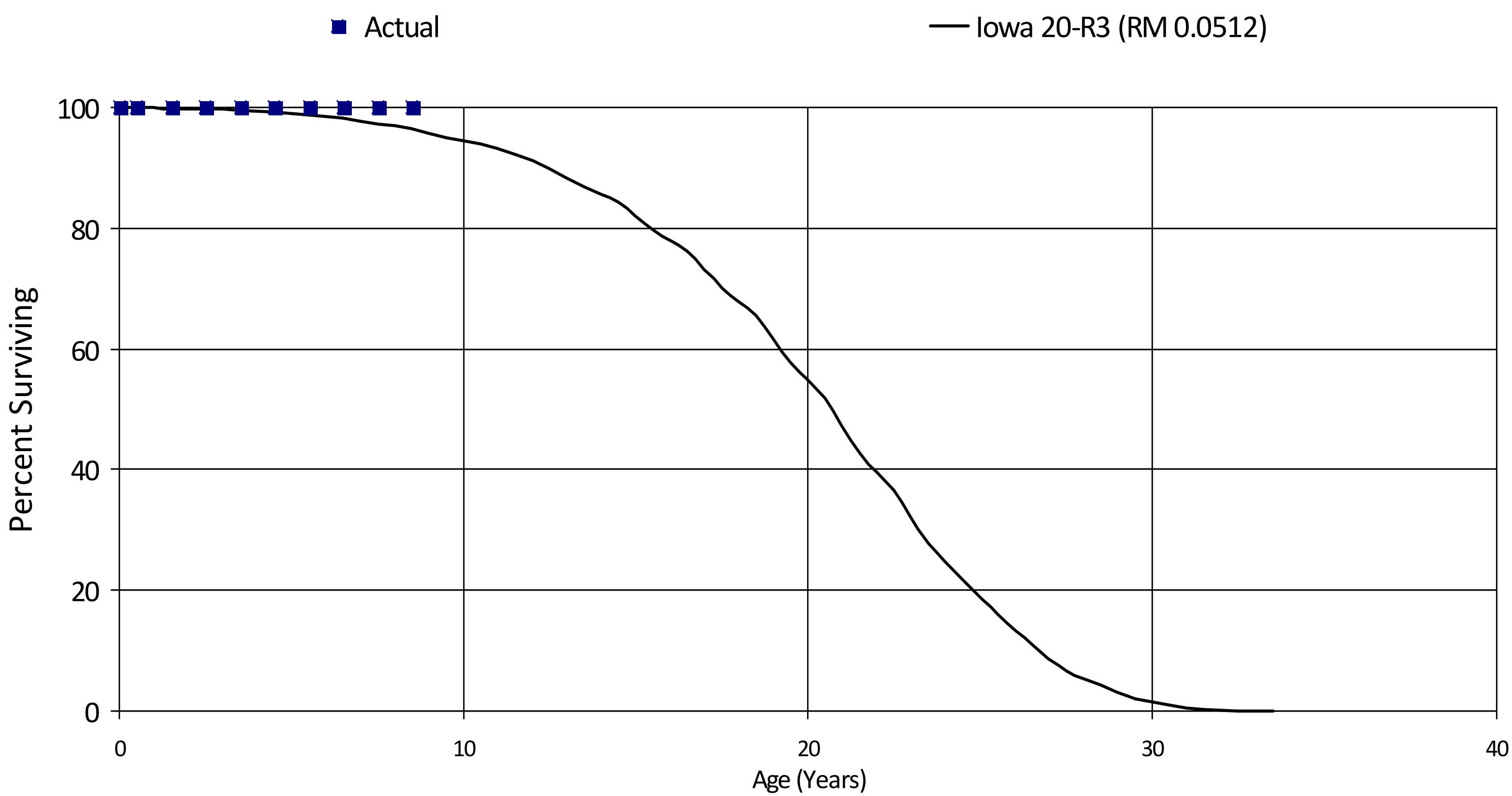
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,314,605	0	0.00000	1.00000	100.00
0.5	1,314,605	0	0.00000	1.00000	100.00
1.5	1,264,605	0	0.00000	1.00000	100.00
2.5	1,087,713	0	0.00000	1.00000	100.00
3.5	1,087,713	0	0.00000	1.00000	100.00
4.5	1,087,713	377,499	0.34706	0.65294	100.00
5.5	680,222	0	0.00000	1.00000	65.29
6.5	674,841	0	0.00000	1.00000	65.29
7.5	663,437	0	0.00000	1.00000	65.29
8.5	623,174	0	0.00000	1.00000	65.29
9.5	586,583	0	0.00000	1.00000	65.29
10.5	380,825	0	0.00000	1.00000	65.29
11.5	276,530	0	0.00000	1.00000	65.29
12.5	236,156	0	0.00000	1.00000	65.29
13.5	236,156	0	0.00000	1.00000	65.29
14.5	236,156	0	0.00000	1.00000	65.29
15.5	159,965	79,995	0.50008	0.49992	65.29
16.5	75,018	10,757	0.14339	0.85661	32.64
17.5	53,618	0	0.00000	1.00000	27.96
18.5	53,618	0	0.00000	1.00000	27.96
19.5	53,618	0	0.00000	1.00000	27.96
	Totals:	468,251			

BC Hydro Power Authority

Account 83002 - Boat, Tugboat

Placement Band - 1996 - 2012 Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 83002 - Boat, Tugboat

Placement Band - 1996 - 2012   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

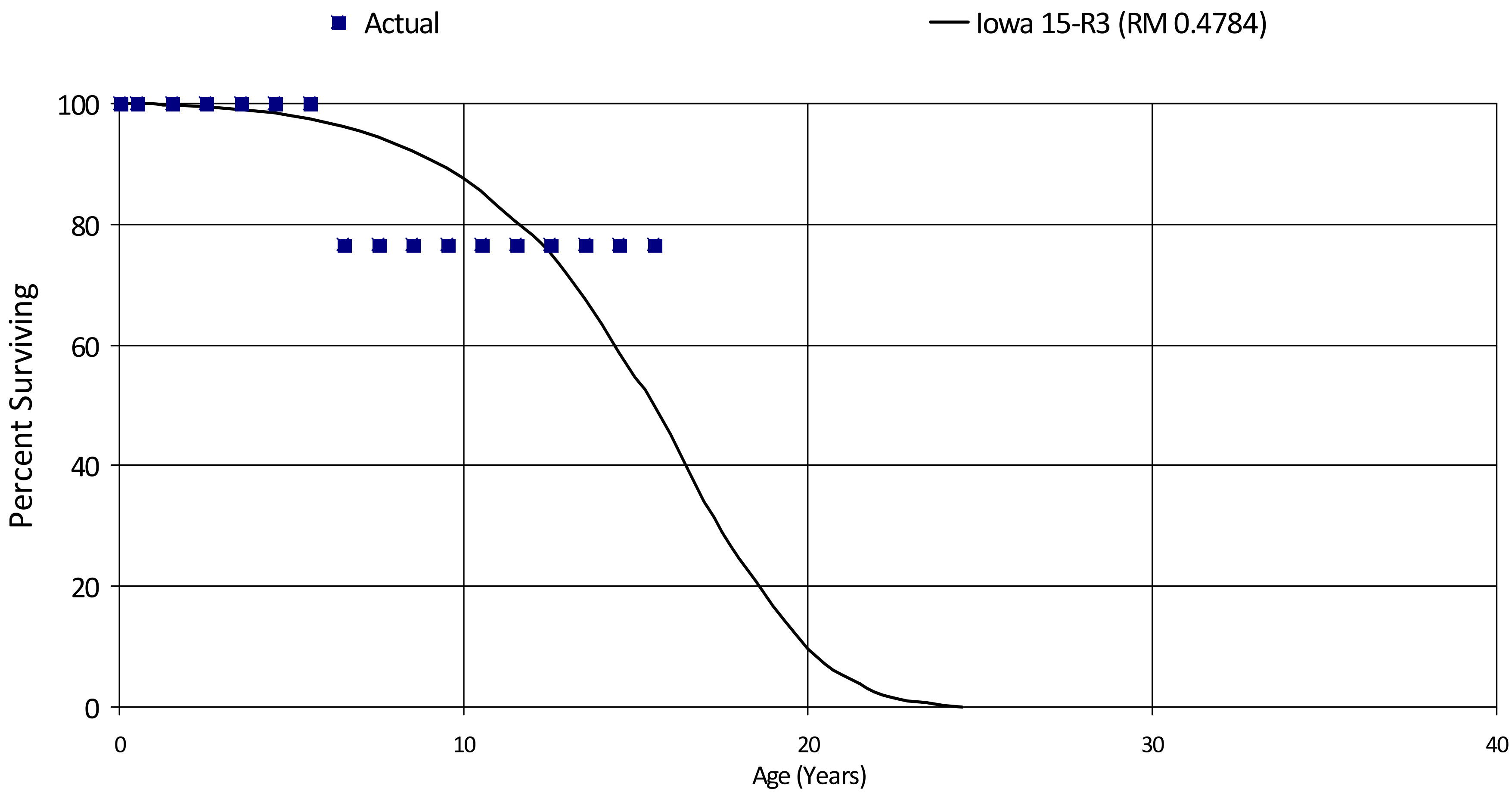
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	0	0	0.00000	1.00000	100.00
0.5	0	0	0.00000	1.00000	100.00
1.5	0	0	0.00000	1.00000	100.00
2.5	0	0	0.00000	1.00000	100.00
3.5	0	0	0.00000	1.00000	100.00
4.5	0	0	0.00000	1.00000	100.00
5.5	0	0	0.00000	1.00000	100.00
6.5	0	0	0.00000	1.00000	100.00
7.5	0	0	0.00000	1.00000	100.00
8.5	0	0	0.00000	0.00000	100.00
	Totals:	0			

BC Hydro Power Authority

Account 88002 - Lab Equipment, Misc

Placement Band - 1997 - 2018   Experience Band - 2013 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 88002 - Lab Equipment, Misc

Placement Band - 1997 - 2018   Experience Band - 2013 - 2020

RETIREMENT RATE ANALYSIS

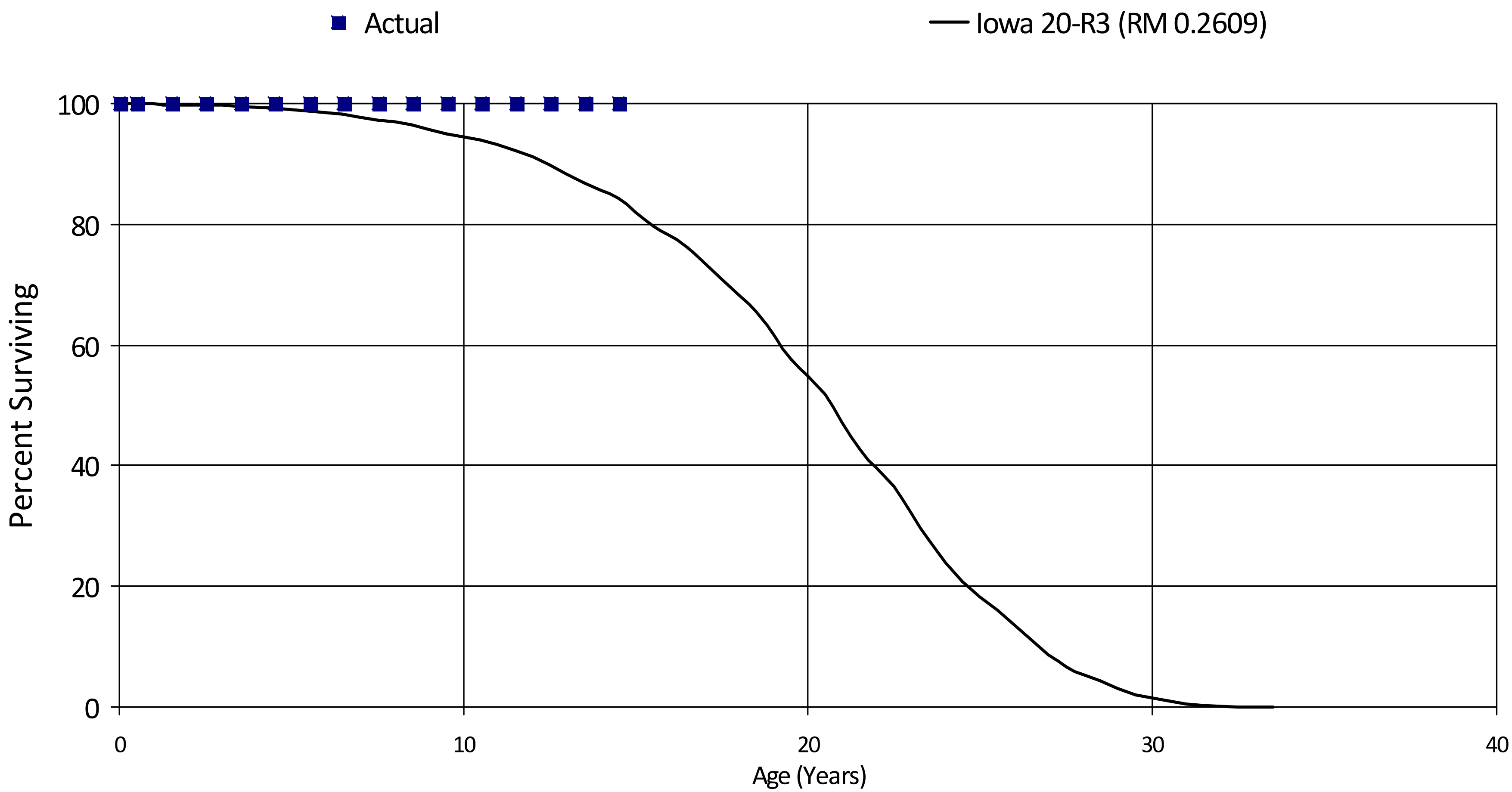
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,252,110	0	0.00000	1.00000	100.00
0.5	1,252,110	0	0.00000	1.00000	100.00
1.5	1,252,110	0	0.00000	1.00000	100.00
2.5	1,219,932	0	0.00000	1.00000	100.00
3.5	1,219,932	0	0.00000	1.00000	100.00
4.5	791,428	0	0.00000	1.00000	100.00
5.5	791,428	184,429	0.23303	0.76697	100.00
6.5	606,999	0	0.00000	1.00000	76.70
7.5	58,644	0	0.00000	1.00000	76.70
8.5	27,163	0	0.00000	1.00000	76.70
9.5	27,163	0	0.00000	1.00000	76.70
10.5	27,163	0	0.00000	1.00000	76.70
11.5	27,163	0	0.00000	1.00000	76.70
12.5	27,163	0	0.00000	1.00000	76.70
13.5	27,163	0	0.00000	1.00000	76.70
14.5	27,163	0	0.00000	1.00000	76.70
15.5	27,163	16,812	0.61892	0.38108	76.70
	Totals:	201,241			

BC Hydro Power Authority

Account 89501 - Animal Preventative Equipment

Placement Band - 2003 - 2019   Experience Band - 2020 - 2020

Actual and Smooth Survivor Curves



BC Hydro Power Authority

Account 89501 - Animal Preventative Equipment

Placement Band - 2003 - 2019   Experience Band - 2020 - 2020

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	14,065,222	0	0.00000	1.00000	100.00
0.5	14,065,222	0	0.00000	1.00000	100.00
1.5	13,467,525	0	0.00000	1.00000	100.00
2.5	11,173,714	0	0.00000	1.00000	100.00
3.5	9,692,539	0	0.00000	1.00000	100.00
4.5	8,398,170	0	0.00000	1.00000	100.00
5.5	6,787,648	0	0.00000	1.00000	100.00
6.5	6,659,578	0	0.00000	1.00000	100.00
7.5	5,618,324	0	0.00000	1.00000	100.00
8.5	5,239,567	0	0.00000	1.00000	100.00
9.5	4,614,017	0	0.00000	1.00000	100.00
10.5	3,084,375	0	0.00000	1.00000	100.00
11.5	2,530,623	0	0.00000	1.00000	100.00
12.5	2,105,356	0	0.00000	1.00000	100.00
13.5	1,430,920	0	0.00000	1.00000	100.00
14.5	708,801	0	0.00000	1.00000	100.00
	Totals:	0			

SECTION 6

6 NET SALVAGE

BC Hydro
GENERATION ACCOUNTS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2011	2,074,193	-4,135,050	-199		0	4,135,050	199					4,135,050	199
2012	23,584,902	-4,859,458	-21		0	4,859,458	21					4,497,254	35
2013	4,106,541	-5,032,923	-123		0	5,032,923	123					4,675,810	47
2014	1,608,075	-6,012,781	-374		0	6,012,781	374	5,301,721	54			5,010,053	64
2015	491,067	-6,683,398	-1,361		0	6,683,398	1,361	5,909,701	286			5,344,722	84
2016	602,467	853,097	142		0	-853,097	-142	3,947,694	438	4,347,093	72	4,311,752	80
2017	20,390,902	-4,979,349	-24		0	4,979,349	24	3,603,217	50	4,371,071	80	4,407,123	58
2018	167,255,218	-26,457,762	-16		0	26,457,762	16	10,194,671	16	8,656,039	23	7,163,453	26
2019	10,578,940	-6,603,545	-62		0	6,603,545	62	12,680,219	19	8,774,192	22	7,101,241	28
2020	4,447,900	-26,209,649	-589		0	26,209,649	589	19,756,986	33	12,679,442	31	9,012,082	38
TOTAL	**235,140,207**	**-90,120,819**	`	**0**		**90,120,819**	38						

BC Hydro
DISTRIBUTION ACCOUNTS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2011	1,412,166	-9,379,690	-664		0	9,379,690	664					9,379,690	664
2012	2,902,296	-9,623,444	-332		0	9,623,444	332					9,501,567	440
2013	92,834,580	-10,734,806	-12		0	10,734,806	12					9,912,647	31
2014	21,018,604	-14,041,116	-67		0	14,041,116	67	11,466,455	29			10,944,764	37
2015	21,455,985	-14,768,168	-69		0	14,768,168	69	13,181,363	29			11,709,445	42
2016	33,395,579	-17,156,301	-51		0	17,156,301	51	15,321,862	61	13,264,767	39	12,617,254	44
2017	25,622,290	-21,572,619	-84		0	21,572,619	84	17,832,363	66	15,654,602	40	13,896,592	49
2018	30,014,786	-26,092,328	-87		0	26,092,328	87	21,607,083	73	18,726,107	71	15,421,059	54
2019	32,784,899	-24,758,035	-76		0	24,758,035	76	24,140,994	82	20,869,490	73	16,458,501	57
2020	25,695,130	-23,996,065	-93		0	23,996,065	93	24,948,810	85	22,715,070	77	17,212,257	60
TOTAL	**287,136,317**	**-172,122,573**	-60	**0**		**172,122,573**	60						

BC Hydro

TRANSMISSION ACCOUNTS

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2011	5,305,799	-4,764,882	-90		0	4,764,882	90					4,764,882	90
2012	3,019,711	-5,940,476	-197		0	5,940,476	197					5,352,679	129
2013	6,796,164	-6,094,487	-90		0	6,094,487	90					5,599,949	111
2014	7,101,866	-11,667,217	-164		0	11,667,217	164	7,900,727	140			7,116,766	128
2015	7,966,587	-7,062,223	-89		0	7,062,223	89	8,274,642	114			7,105,857	118
2016	8,782,467	-8,927,374	-102		0	8,927,374	102	9,218,938	116	7,938,356	118	7,409,443	114
2017	9,105,212	-14,270,476	-157		0	14,270,476	157	10,086,691	117	9,604,355	121	8,389,591	122
2018	10,013,049	-12,809,322	-128		0	12,809,322	128	12,002,391	129	10,947,322	127	8,942,057	123
2019	9,723,064	-8,835,148	-91		0	8,835,148	91	11,971,648	125	10,380,908	114	8,930,178	119
2020	7,515,453	-6,627,964	-88		0	6,627,964	88	9,424,145	104	10,294,057	114	8,699,957	115
TOTAL	**75,329,370**	**-86,999,570**		**0**		**86,999,570**	115						

BC Hydro
GENERAL/OTHER ACCOUNTS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2011	10,545,235	-499,356	-5		0	499,356	5					499,356	5
2012	2,239,363	-57,837	-3		0	57,837	3					278,596	4
2013	9,828,630	-181,792	-2		0	181,792	2					246,328	3
2014	11,797,258	-202,763	-1.7		0	202,763	2	147,464	2			235,437	3
2015	17,704,273	-1,816,990	-10		0	1,816,990	10	733,848	6			551,747	5
2016	28,540,266	-1,695,767	-6		0	1,695,767	6	1,238,507	6	791,030	6	742,417	6
2017	27,281,809	-1,578,500	-6		0	1,578,500	6	1,697,086	7	1,095,162	6	861,858	6
2018	24,922,891	-1,939,226	-8		0	1,939,226	8	1,737,831	6	1,446,649	7	996,529	6
2019	35,788,595	-1,316,806	-4		0	1,316,806	4	1,611,510	5	1,669,458	6	1,032,115	6
2020	19,295,012	-630,870	-3		0	630,870	3	1,295,634	5	1,432,234	5	991,991	5
TOTAL	**187,943,334**	**-9,919,906**		**0**		**9,919,906**	5						

7 ESTIMATION OF SURVIVOR CURVES

7.1 Average Service Life

All assets have a service life, which is defined as "the period of time from its installation until it is retired from service"[4]. All account groups of property are made up of various assets with differing service lives and investment values. To calculate a depreciation rate, one must first calculate an average life for all assets in a single account. This can be done by ascertaining the age at retirement for every asset in an account and plotting it as a percentage of the units surviving at each age interval (a "Survivor Curve"). From the average life for each account, remaining lives can then be found which are then used to calculate the annual depreciation accruals and ultimately depreciation rate. A discussion of the general concept of survivor curves is presented and the Iowa type survivor curves are reviewed.

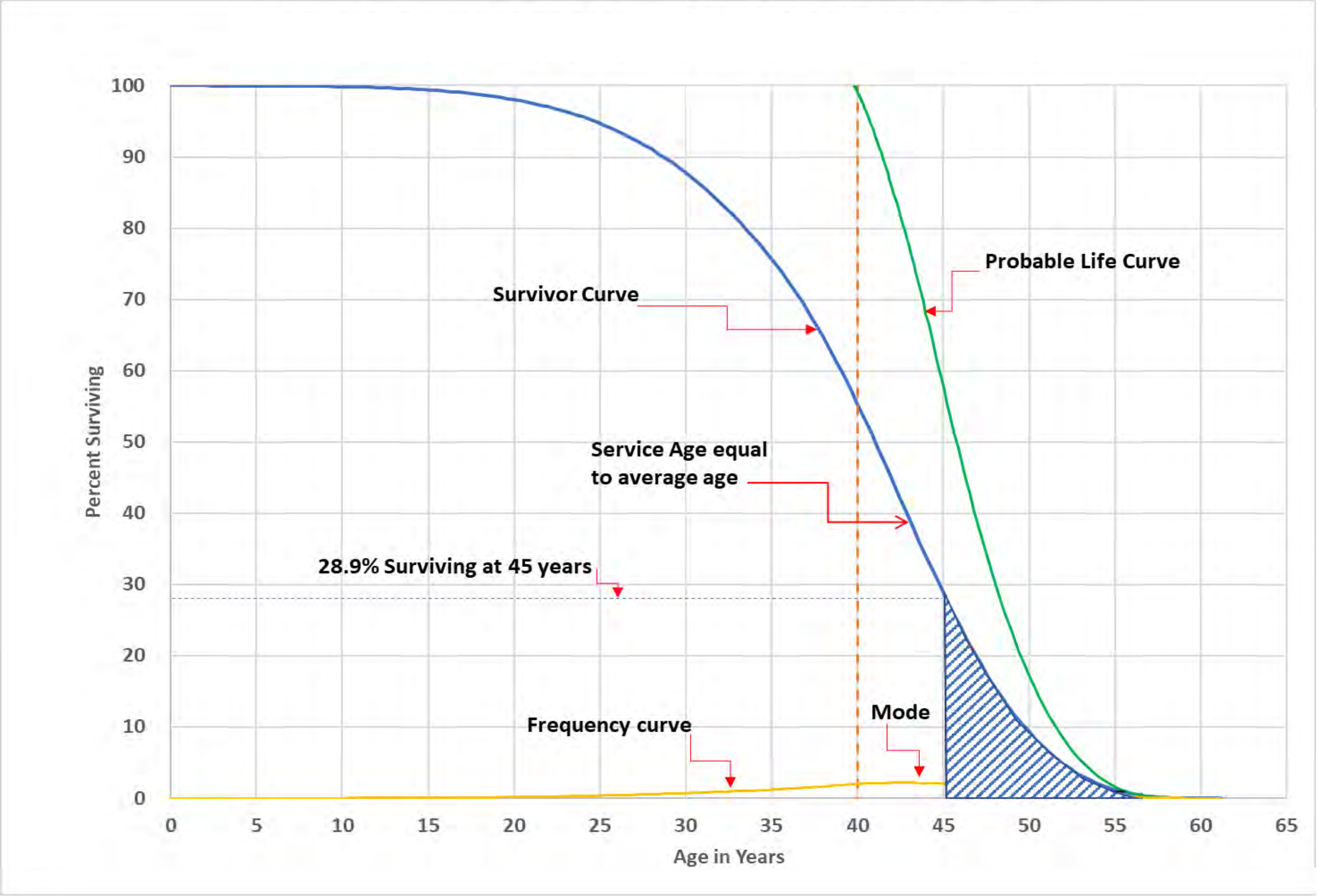
7.2 Survivor Curves

A survivor curve is defined as "a graph of the percent of units remaining in service expressed as a function of age"[5] . To calculate the average life of the group, the remaining life expectancy, the probable life and the frequency curve, one must first create a survivor curve. Figure 1 shows a typical 40-R4 smoothed survivor curve as well as the accompanying derived curves. The type 40-R4 refers to the Iowa type curve, whose designation will be explained in further detail in the next section

To calculate the average service life, one must calculate the area under the survivor curve and divide by the percent surviving at age zero. The remaining life is equal to the area under the survivor curve and to the right of the current age, divided by the percent surviving at the current age. In Figure 1, for example, the hatched area to the right of age 45 divided by 28.9 percent surviving balance represents the remaining life for an asset that has reached that age. The probable life is "the total life expectancy of the property surviving at any age and is equal to the remaining life plus the current age."[6] If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve is calculated by taking the difference between the percent surviving on successive years on the survivor curve [7]. Alternatively, frequency can be empirically determined by finding the amount of retirements at any given age. Plotting retirement frequency from the youngest to oldest ages and then taking the cumulative frequencies will generate percent surviving versus age.

[4] Wolf, Frank K. and W. Chester Fitch, Depreciation Systems (Iowa State University Press, 1994), 21.
[5] *Ibid*, 23.
[6] *Ibid*, 29.
[7] *Ibid*, 23-24.

FIGURE 1: TYPICAL SURVIVOR CURVE (40-R4) AND DERIVED CURVES



7.3 Iowa Type Curves

In 1931, Robley Winfrey and Edwin Kurtz of the Engineering Research Institute at Iowa State University published Bulletin 103, which laid the groundwork for what would eventually be known as the Iowa Curves. "The 13 type curves can be used as valuable aids in forecasting the probable future service lives of individual items and of groups of items of different kinds of physical equipment"[8]. The 13 curves described in Bulletin 103 eventually became a series of 22 generalized survivor curves which are used throughout the regulated utility industry. These 22 curves were described in Bulletin 125, published in 1967 by Harold A. Cowles, which became known as the Iowa curves.

The Iowa curves are organized with three variables: the average life of the plant; the location of the mode; and the variation of the life. All Iowa curves have both a letter and a number to represent the shape and height of the mode. The L curves, or left-moded curves, are used when the mode of the curve should be to the left of the average life. There are six L curves are presented in Figure 2. The R curves, or right-moded, are used when the mode of the curve should be to the right of the average life. There are five R curves, which are presented in Figure 3. The S curves, or symmetrically-moded, are used when the mode is equal to the average life. There are seven S curves, which are presented in Figure 4. The O curves, or origin curves, are used when the mode occurs at age 0. There are four O curves, which are presented in Figure 5. There are some occasions where it is appropriate to use a half curve. In these cases, the curve is assumed to be exactly half way between the two curves.

In addition to Bulletin 125, Iowa curves have also been presented in subsequent Experiment Station bulletins and in the text Engineering Valuation and Depreciation [9]. In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis [10] presenting his development of the fourth family consisting of the four O-type survivor curves.

[8] *Ibid*, 21

[9] Marston, Anson, Robley Winfrey and Jean C. Hempstead, Engineering Valuation and Depreciation (The Iowa State University Press, 1953)

[10] Couch, Frank V. B., Jr., Classification of Type O Retirement Characteristics of Industrial Property Unpublished M.S. Thesis (Engineering Valuation, Library, Iowa State College, Ames, Iowa, 1957).

FIGURE 2: LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

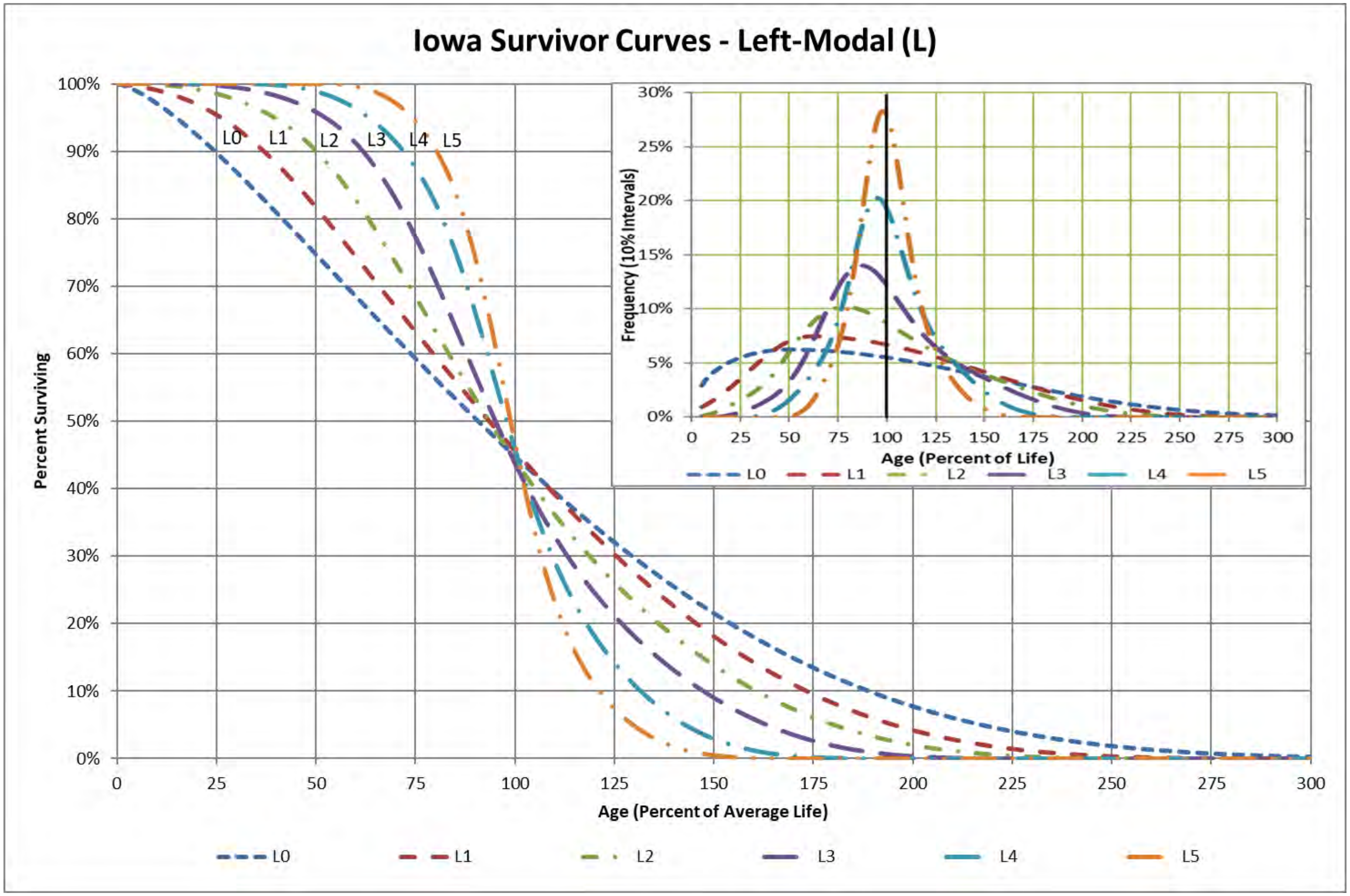


FIGURE 3: RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

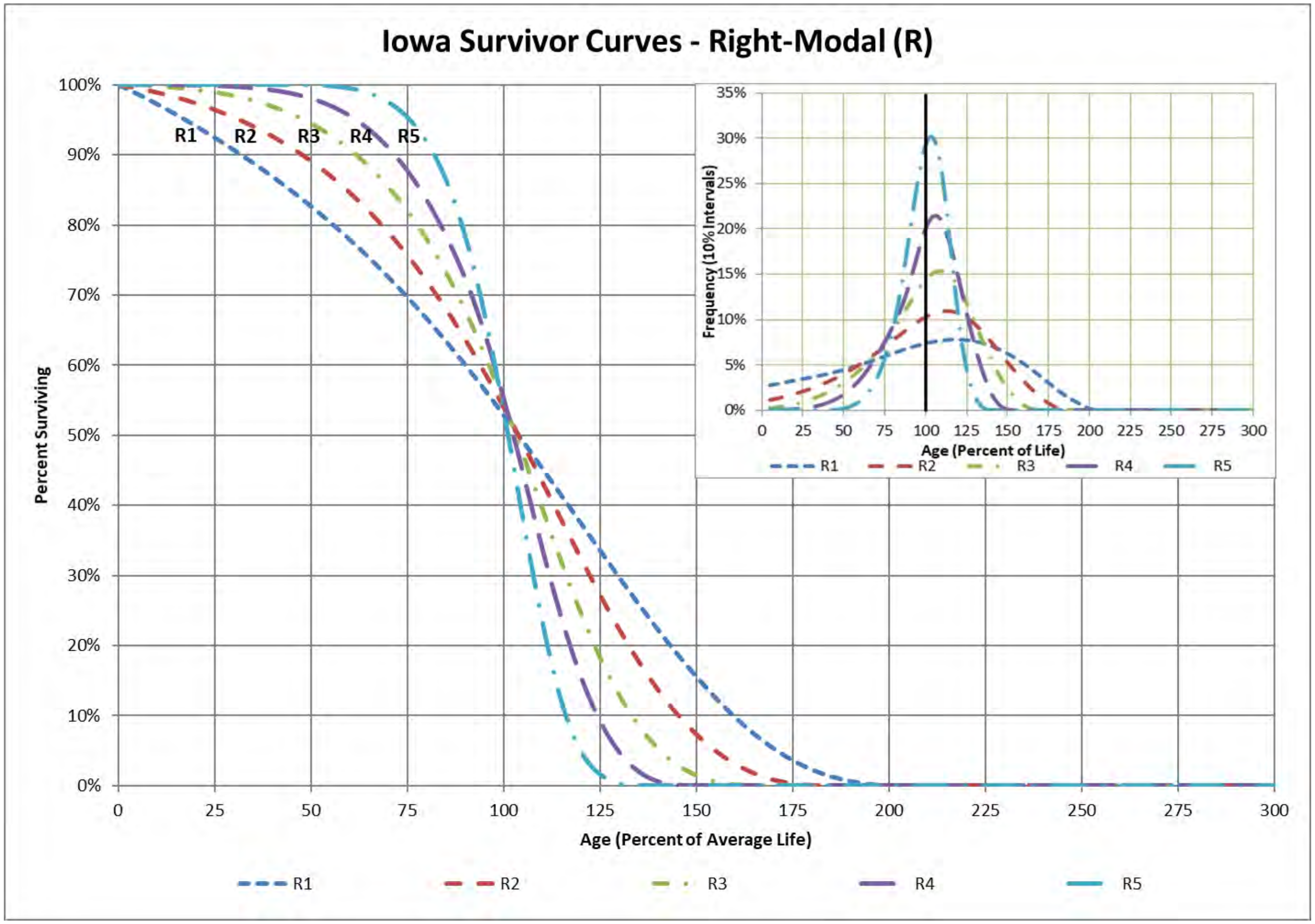


FIGURE 4: SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

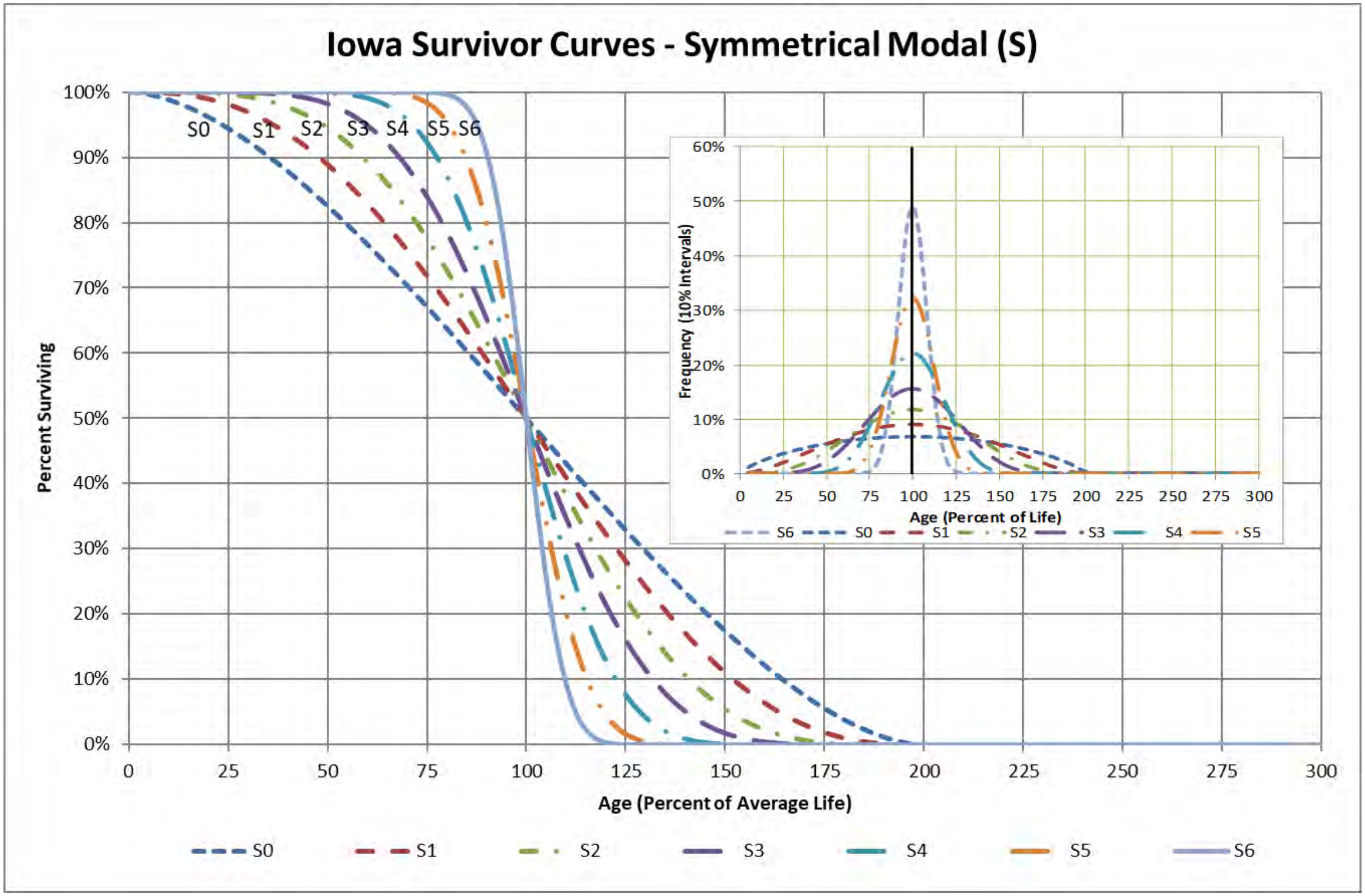
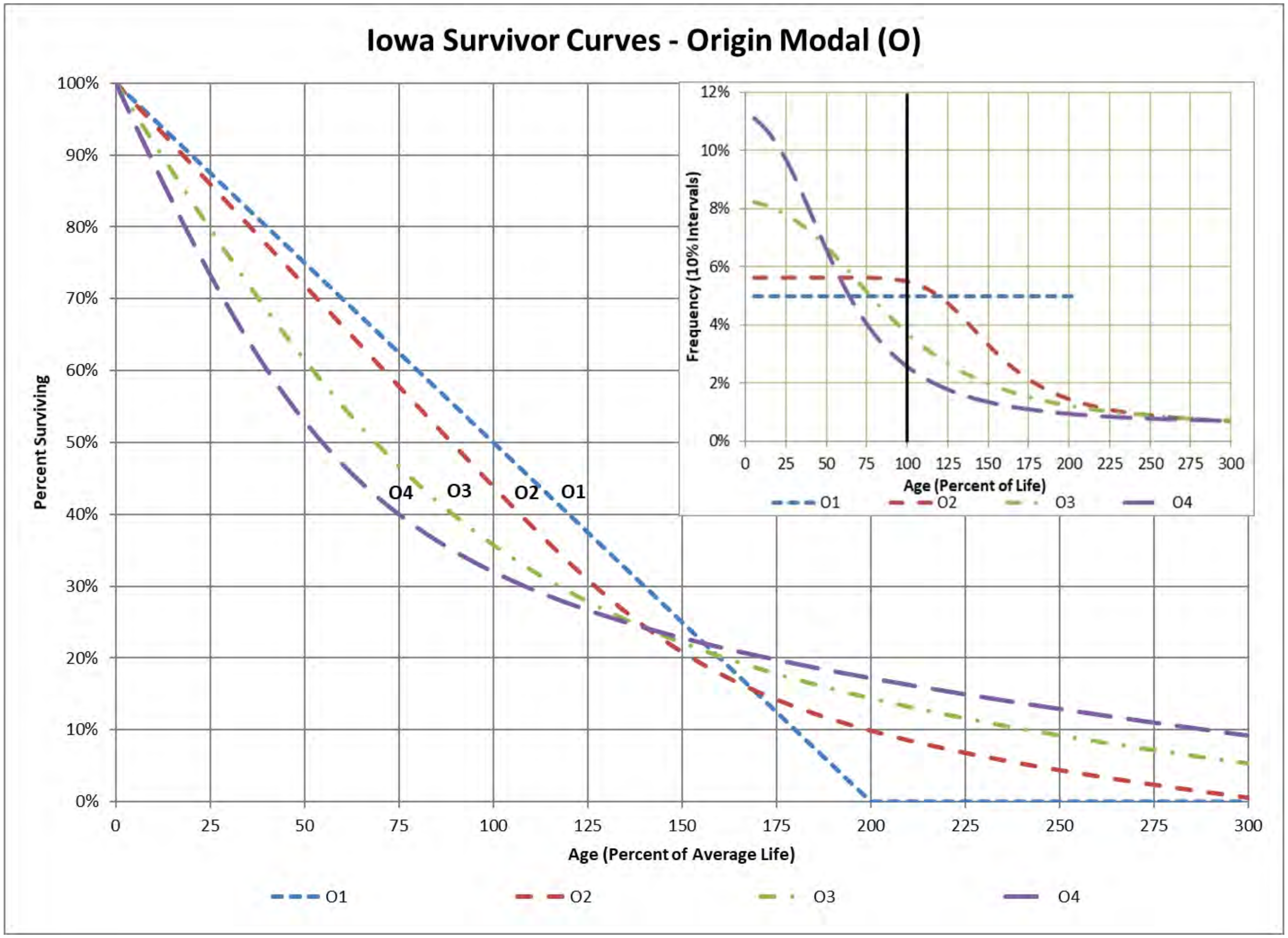


FIGURE 5: ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES



7.4 Retirement Rate Method of Analysis

The retirement rate method is a widely accepted actuarial method used to create survivor curves. This method is also referred to as an original life table. These survivor curves can then be used to determine the average service life of a plant account. The retirement rate method is thoroughly explained in several publications, including Statistical Analyses of Industrial Property Retirements,[11] Engineering Valuation and Depreciation [12] and Depreciation Systems [13].

The retirement rate method is a subgroup of the placement and the experience band methods, as described in "Depreciation Systems". The placement band method creates a survivor curve which describes the life characteristics of assets placed into service during a selected timeframe. The experience band method creates a survivor curve which describes the life characteristics of assets removed from service during a selected time frame. The retirement rate method creates both placement and experience bands to give the most complete or representative data. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

7.5 Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2008-2017 during which there were placements during the years 2003-2017. In order to illustrate the summation of the aged data by age interval, the data was compiled in the manner presented in Schedules 1 and 2. In Schedule 1 (page 9-10), the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the asset invested in 2003 were retired in 2008. The $10,000 retirement occurred during the age interval between 4 ½ and 5 ½ years (2008 - 2003) on the basis that approximately one-half of the amount of property was installed prior to and after July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2008 retirements of 2003 installations and ending with the 2016 retirements of the 2011 installations. Thus, the total amount of $143,000 for age interval 4½-5½ equals the sum of:

$10 + $12 + $13 + $11 + $13 + $13 + $15 + $17 + $19 + $20= $143 k

[11] Anson, Winfrey & Hempstead, supra note 7
[12] Anson, Winfrey & Hempstead, supra note 7
[13] Wolf & Fitch, supra note 2

Other transactions which affect the group are recorded in a similar manner in Schedule 2 (page 9-11). The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements but are used in developing the exposures at the beginning of each age interval.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2008-2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

Retrements (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2004	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2005	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2006	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2007	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2008	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2009		5	11	12	13	14	15	16	18	20	113	7½-8½
2010			6	12	13	15	16	17	19	19	124	6½-7½
2011				6	13	15	16	17	19	19	131	5½-6½
2012					7	14	16	17	19	20	143	4½-5½
2013						8	18	20	22	23	146	3½-4½
2014							9	20	22	25	150	2½-3½
2015								11	23	25	151	1½-2½
2016									11	24	153	½-1½
2017										13	80	0-½
Total	**53**	**68**	**86**	**106**	**128**	**157**	**196**	**231**	**273**	**308**	**1,606**	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2008-2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017 Placement Band 2003-2017

Acquisitions, Transfers and Sales (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2004	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2005	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2006	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2007	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2008	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2009		-	-	-	-	-	-	-	-	-	-	7½-8½
2010			-	-	-	-	-	-	-	-	-	6½-7½
2011				-	-	-	-	(12)[b]	-	-	-	5½-6½
2012					-	-	-	-	22[a]	-	-	4½-5½
2013						-	-	(19)[b]	-	-	10	3½-4½
2014							-	-	-	-	-	2½-3½
2015								-	-	(102)[c]	(121)	1½-2½
2016									-	-	-	½-1½
2017												0-½
Total	**-**	**-**	**-**	**-**	**-**	**-**	**60**	**(30)**	**22**	**(102)**	**(50)**	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses denote Credit amount.

7.6 Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 (page 9-13). The surviving plant at the beginning of each year from 2007 through 2016 is recorded by year in the portion of the table titled "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition, are obtained by adding or subtracting the net entries shown on Schedules 1 and

2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2013 are calculated in the following manner:

Exposures at age 0	=	amount of addition	=	$750,000
Exposures at age ½	=	$750,000 - $ 8,000	=	$742,000
Exposures at age 1½	=	$742,000 - $18,000	=	$724,000
Exposures at age 2½	=	$724,000 - $20,000 - $19,000	=	$685,000
Exposures at age 3½	=	$685,000 - $22,000	=	$663,000

For the entire experience band 2008-2018, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

$255 + $268 + $ 284 + $311 + $334 + $374 + $405 + $448 + $501 $ $609 = $3,789k

SCHEDULE 3 – PLANT EXPOSED TO RETIREMENT AT THE BEGINNING OF EACH YEAR, 2008 -2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008 - 2017

Placement Band 2003-2017

Exposures (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total at Beginning of Age Interval (12)	Age Interval (13)
2003	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2004	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2005	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2006	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2007	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2008	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2009		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2010			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2011				580[a]	574	561	546	530	501	482	3,057	5½-6½
2012					660[a]	653	639	623	628	609	3,789	4½-5½
2013						750[a]	742	724	685	663	4,332	3½-4½
2014							850[a]	841	821	799	4,955	2½-3½
2015								960[a]	949	923	5,719	1½-2½
2016									1,080[a]	1,069	6,579	½-1½
2017										1,220[a]	7,490	0-½
Total	**1,975**	**2,382**	**2,724**	**3,318**	**3,872**	**4,494**	**5,247**	**5,987**	**6,852**	**7,796**	**44,780**	

[a] *Additions during the year.*

1555	1922	2214	2738	3212	3744	4397	5027	5772	6576	44780
420	460	510	580	660	750	850	960	1080	1220	0
1975	2382	2724	3318	3872	4494	5247	5987	6852	7796	44780

7.7 Original Life Tables

The original life table, illustrated in Schedule 4 (page 9-15) is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100 percent at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15		
Exposures at age 4½	=	$3,789,000		
Retirements from age 4½ to 5½	=	$143,000		
Retirement Ratio	=	$143,000 ÷ $3,789,000	=	0.0377
Survivor Ratio	=	1.000 - 0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15) x (0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless. The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

SCHEDULE 4: ORIGINAL LIFE TABLE - CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2008-2017					Placement Band 2003-2017
Age at Beginning of Interval	**Exposures at Beginning of Age Interval**	**Retirements During Age Interval**	**Retirement Ratio**	**Survivor Ratio**	**% Surviving at Beginning of Age Interval**
0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.6
12.5	323	44	0.1362	0.8638	48.9
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	**44,780**	**1,606**			

- Exposure and Retirement Amounts are in Thousands of Dollars
- Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
- Column 3 from Schedule 1, Column 12, Retirements for Each Year.
- Column 4 = Column 3 divided by Column 2.
- Column 5 = 1.0000 minus Column 4.
- Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

7.8 Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100 percent to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percentages surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

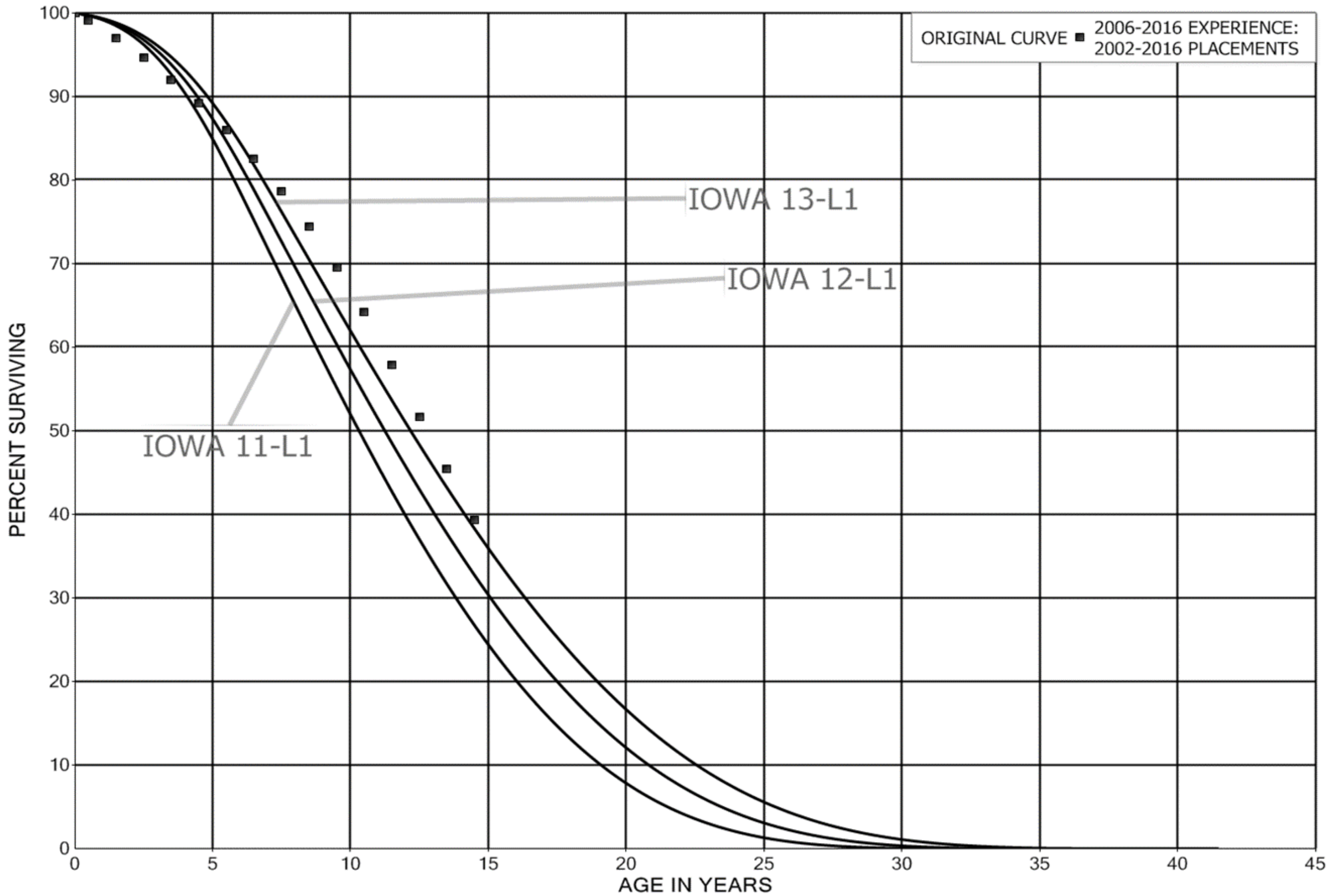


FIGURE 7: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A SO IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

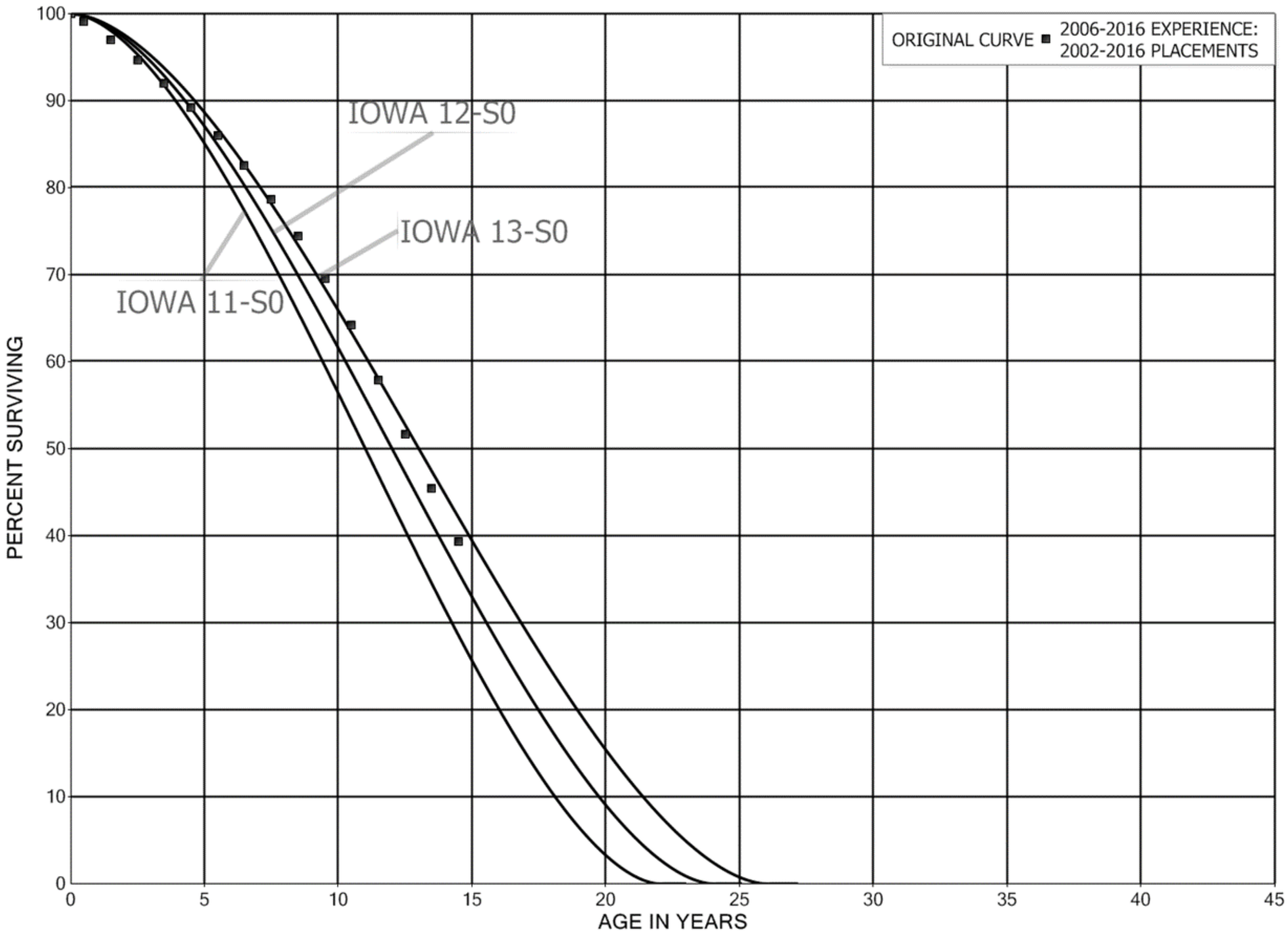


FIGURE 8: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A R1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

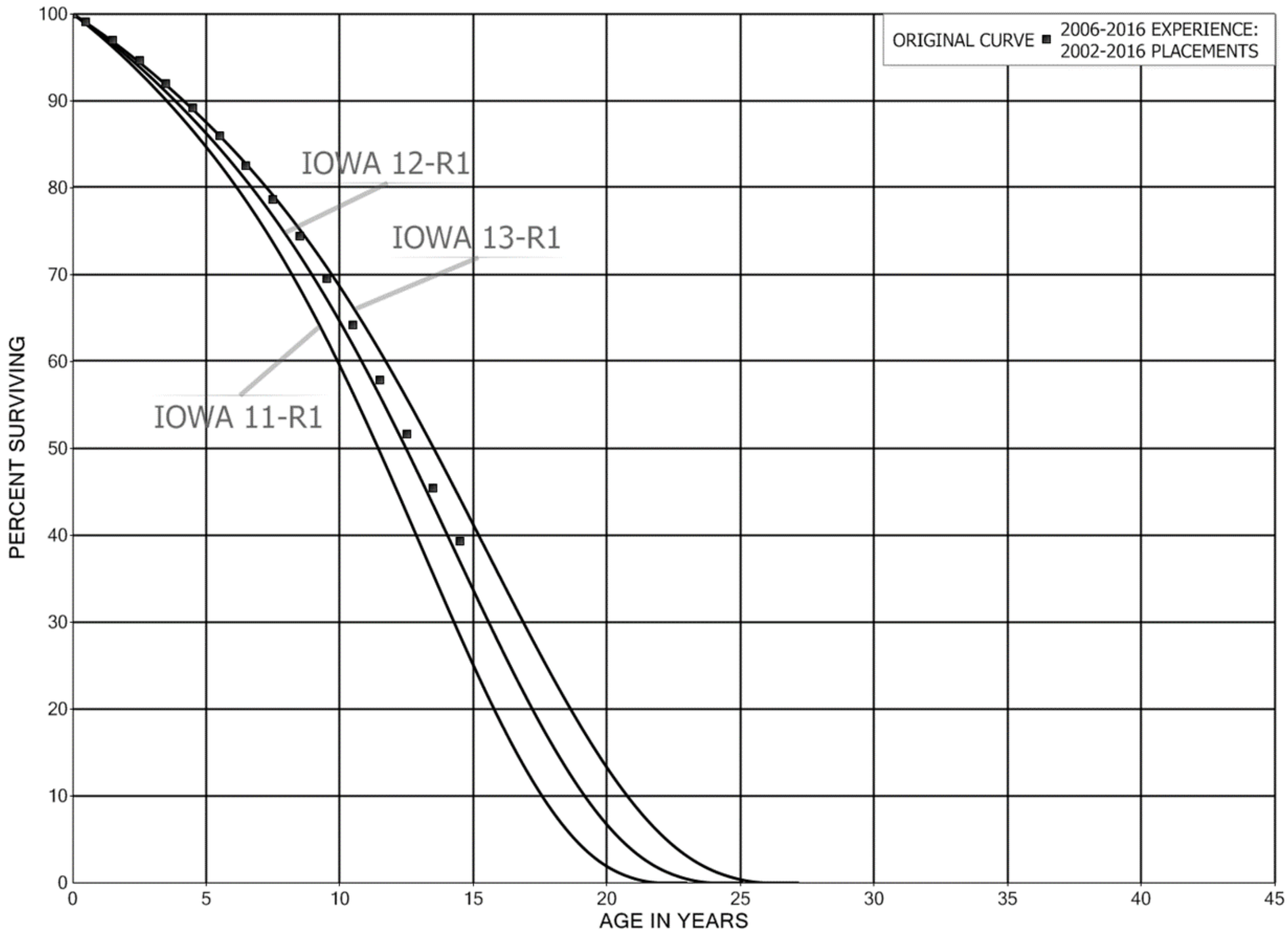
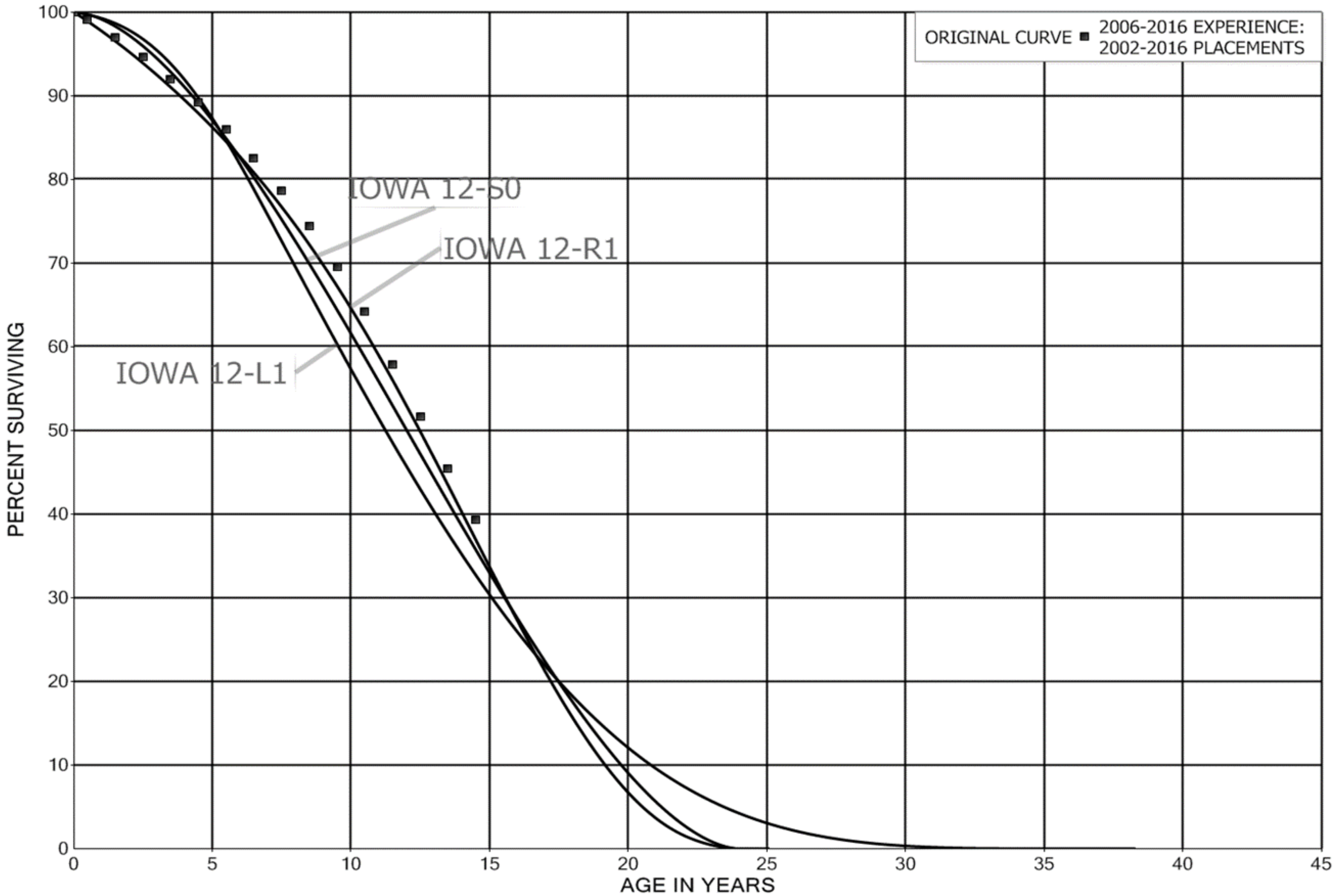


FIGURE 9: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES



BRITISH COLUMBIA UTILTIES COMMISSION

IN THE MATTER OF an application by BC Hydro

BC HYDRO

REPORT ON APPLICABILITY OF INCLUSION OF NET SALVAGE IN THE DEPRECIATION RATE CALCULATIONS

DRAFT

August 31, 2021

WRITTEN EVIDENCE OF

CONCENTRIC ADVISORS ULC.

TABLE OF CONTENTS

I. Introduction

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

My name is Larry E. Kennedy, and my business address is 200 Rivercrest Drive, Suite 277, Calgary Alberta T2C 2X5.

Q2. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

I am a Senior Vice President of Concentric Advisors ULC, a wholly owned Canadian subsidiary of Concentric Energy Advisors ("Concentric"). Concentric is a management consulting firm specializing in financial and economic services to the energy industry.

Q3. WHAT IS YOUR AREA OF EXPERTISE?

I have been employed in the public utility sector in the specialized fields of regulated plant accounting, capital recovery and development of depreciation and capital recovery strategies for over 40 years. I have spent the last 22 years in a consulting role providing expert testimony on the topic of depreciation, regulatory plant accounting, GAAP accounting related to regulated entities, and stranded cost issues. Additionally, I am a member of the teaching faculty of the Society of Depreciation Professionals and have presented to a number of organizations on the topics of depreciation, utility asset valuation and stranded cost. My C.V. and list of testimony are attached to this evidence as Attachment 1.

Q4. WHAT IS THE PURPOSE OF THIS REPORT?

Concentric was retained by BC Hydro to provide this Report to respond to the BCUC Directives in Order G-246-20 stating:

Therefore, the Panel directs BC Hydro to provide in its next RRA, an assessment of whether its current practice of expensing dismantling costs as they occur would result in intergenerational inequity and to provide options on how it could calculate and collect dismantling costs to better promote intergenerational equity. For these reasons, the

Panel approves the use of the Dismantling Cost Regulatory Account, as requested by BC Hydro, for the Test Period only.

Given the intergenerational equity concerns, the Panel directs BC Hydro to include in its upcoming depreciation study a net salvage study and, in the RRA immediately after the completion of the depreciation and net salvage studies, report on the results and recommendations, as well as BC Hydro's plan to implement those recommendations"[1]

This report will provide a conceptual background related to the options available for the recovery of the of future cost of removal/retirement options (including the policy of expensing dismantling costs upon occurrence), potential implementation strategies for each of the options and provides Concentric's recommendations on both the approach and implementation.

Q5. HOW IS THE BALANCE OF THIS REPORT ORGANIZED?

Part II of this report includes a detailed discussion related to the methods of recovery of future cost of removal/retirement expenditures and is followed by a summary of the methods. Part III provides Concentric's recommendation after consideration is given to all relevant factors. Part IV provides a recommended implementation approach.

II. REVIEW OF POTENTIAL METHODS

Q6. PLEASE SUMMARIZE THE VIABLE OPTIONS FOR CONSIDERATION?

While a number of methods have been proposed throughout North America, I considered the following alternatives to be most applicable in the current BC Hydro circumstances:

1. Use of the Traditional method to calculate the required net salvage percentage;
2. Use of the Constant Dollar Net Salvage (CDNS) to calculate the required net salvage percentage;
3. Expensing cost of removal as incurred (also known as "Pay as you go");
4. Capitalizing cost of removal to the installation cost of replacement; and

---

[1] BCUC Order, Section 4.5.2, page 124 of 204

5. Trust Fund and Securitization methods

Q7. PLEASE DISCUSS THE TRADITIONAL APPROACH.

The use of the Traditional Method of net salvage analysis is the most widely used approach in North America.

With the traditional method, the estimation of net salvage percentages are developed using the following steps:

1. The annual retirement, gross salvage and cost of removal transactions are extracted from the plant accounting systems over a period of observation – normally at least a 10-year period.
2. A net salvage amount (gross salvage proceeds less cost of retirement) is calculated for each historic year. Additionally, a net salvage amount is calculated for each historic three-year rolling band, each historic 5-year rolling band and a life to date rolling band.
3. The net salvage amount determined above is compared to the original booked costs retired for each period in the manner described, which results in a net salvage percentage of original costs retired for each year, in addition to three-year rolling bands and the most recent five-year rolling band.
4. The annual, the three-year rolling average, and the most recent five-year rolling average net salvage percentages are analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage is based purely upon statistical analysis.
5. Each account is then compared to the net salvage percentage currently approved and compared to peer utility companies. Based on the statistical analysis, the review of current and peer company net salvage percentages, and on the professional judgement of the depreciation consultant, a net salvage percentage is determined for each account.
6. The net salvage percentage is then used in the depreciation rate calculations in the depreciation study.

The resultant net salvage percentage can then be either included as part of the depreciation rate calculation thereby being included in the depreciation expense and accumulated depreciation accounts. Alternatively, many organizations (and in particular, those following IFRS) use a second depreciation rate calculation specific to net salvage and carry the depreciation related to net salvage in a separate income statement account and the accumulated balances are recorded in a regulatory deferral account. The deferral account grows to accumulate the future expenditure requirements and is drawn down by those future expenditures at the time of asset retirement.

<u>Advantages of this approach</u>

- Is the method currently approved by the BCUC for FortisBC Inc, FortisBC Energy, and Pacific Northern Gas.
- Is generationally equitable – Those customers benefiting from the asset in service are responsible for the total cost of the asset, including the costs of retirement of the asset.
- Is the most widely used and accepted method for the proactive recovery of cost of retirement/removal expenditures.
- Adjusts for inflation in the future requirement of net salvage – the underlying assumption is that the long-term historic rate of inflation will be indicative of the future long-term rate of inflation.
- Is well understood by most regulators.

<u>Disadvantages of this approach</u>

- Does not deal with the issue of technological change in the assets currently being retired as compared to those historically retired.
- Assumes that the future work to retire assets will be the same as historic work – for example, changing environmental standards are not specifically considered in the calculations.
- Can prematurely erode rate base.

Q8. PLEASE DISCUSS THE CDNS METHOD.

The CDNS approach is similar to the calculations made for the determination of an Asset Retirement Obligation and is therefore consistent with IFRS regarding estimating future costs of removal. With this method, all historic transactions are revalued to a current cost to allow for a current cost percentage of net salvage with all impacts of historic inflation removed. The current cost estimate is then inflated using unique estimates for future inflation, with the resultant inflated amount potentially discounted to current day dollars to reflect the fact that the dollars collected today will not be used for many years into the future.

There are three components to the development of an appropriate future net salvage percentage for mass property accounts.

Firstly, an estimate of the current net cost of removal of facilities is developed. The ratio of net salvage costs to the original cost of plant retired is developed and used as one indicator of the current estimated cost of removal. In this method, each of the transactions is brought forward to the current point in time, thereby resulting in the historical ratio of cost of removal to original costs being retired having all impacts of inflation removed.

The second component step is to determine the cost required at the time of forecast retirement. Once the current estimate of the net costs of removal are established, the current estimate needs to be adjusted to recognize the impacts of inflation over the estimated remaining life of the account. In developing the inflation estimate to be applied to the current cost of removal estimate, the constant dollar method requires the application of a forward-looking estimate of the rate of inflation for labour costs associated with the retirement of facilities. The rate of inflation for labour costs is the primary driver of the future costs of retirement, and as the current cost estimate has had all impacts of inflation removed, an appropriate estimate of the future rate of inflation related to labour must be estimated. Such estimates are usually based on the company's inflation rates used in long term capital forecasts for future system expenditures or from published long term economic forecasts of inflation.

Lastly, to recognize that the funds collected in current periods will not be expensed until potentially many years into the future, a discounted cash flow calculation is required. In this manner, the fact that the utility has received the benefit of the funds as working capital through the inclusion of the requirement into the current period revenue requirements, an appropriate discount rate to discount the future cash expenditures to the current period must be estimated.

Advantages of this approach

- Is the method currently approved by the OEB for Enbridge Gas.
- Is generationally equitable – Those customers benefiting from the asset in service are responsible for the total cost of the asset, including the costs of retirement of the asset.
- Adjusts for inflation in the future requirement of net salvage – an independent estimate of the future levels of inflation are used rather than the assumption that the historic levels of inflation will be repeated in the future.
- Reduces the net negative salvage burden on current customers – through the use of the discounting the current recovery is assumed to reduce the requirement for credit or other financing for current operations.
- Calculations are similar to ARO calculations – as such, the external accounting community tends to like this form of estimation of the future costs.

Disadvantages of this approach

- The calculations are complex resulting in an increased burden in explaining to the regulator and customer groups. Often the method is rejected because of the complexity.
- Requires specific estimates of historic inflation and future discount rates.

Q9. PLEASE DISCUSS THE METHOD TO EXPENSE COST OF REMOVAL AS INCURRED (PAY AS YOU GO APPROACH).

With this method, as currently used by BC Hydro, the required cost of removal/retirement is estimated by the utility for the test period and included into the revenue requirement. This method, also known as the “Pay as you Go” approach, is most widely used in circumstances where the applicable regulator does not permit inclusion of net negative salvage costs into the depreciation rate calculations, and therefore the cost of removal expenditures are expensed for financial reporting purposes when incurred. This method results in challenges as the expenditures are estimated and included in the revenue requirement during a rate application and recovery is normally approved based on the rate case estimates. There is a risk of either over or under collection through tolls of the actual required amounts. In some circumstances, regulators allow for the differences between the estimated and actual amounts to be deferred until future tests period, at which point the disposition of the deferred account can be established. However, not all regulators allow for any true up of cost differences between the forecast and actual amounts.

Advantages of this approach

- No estimate of either historic or future inflation required – given that the costs are current there is no need to factor for future inflation in the estimated amounts.
- The calculations are simple and based on near term estimates for which contracts may be issued at the time of the rate case resulting in reduced forecast error in actual versus estimated costs.
- Is compliant with most accounting guidelines.

Disadvantages of this approach

- Is not generally equitable – the users who benefit from the assets providing utility service are not responsible for the total costs of the asset providing that service.
- There is increased utility risk that cost variances will be to the account of the utility and not recoverable from ratepayers.

Q10. PLEASE DISCUSS THE CAPITALIZING COST OF REMOVAL TO THE INSTALLATION COST OF A REPLACEMENT ASSET.

In recent years, some utilities reporting under IFRS have adopted a hybrid approach, wherein costs of removal associated with replacement projects are charged to the installation costs associated with the new asset. This method is limited to the ability to consider the removal of the old (or replaced) assets to be an integral function to prepare the site for the installation of the new asset in accordance with IAS 16. Utilities have developed varying interpretations of this requirement, with some utilities requiring the replacement asset to be in the exact same location (same hole for Poles, same foundation base for transformers, etc.), while others have taken a more liberal approach to the replacement assets being within the same area (often arguing the replaced asset must be removed for site access etc.).

In circumstances where the "site preparation or directly attributable" argument cannot be made, the costs of removal of the replaced assets are generally expensed as incurred or held for future treatment within a deferred account.

Advantages of this approach

- No estimate of either historic or future inflation required – given that the costs are current there is no need to factor for future inflation in the estimated amounts. Additionally, the original cost of the replaced assets is not considered in this in this calculation; therefore, any impact of historic inflation is not relevant.
- The calculations are simple and based on near-term estimates for which contracts may be issued at the time of the rate case, resulting in reduced forecast error in actual versus estimated costs.
- Meets IFRS guidelines – reduces the need for any type of regulatory deferral account treatment.

Disadvantages of this approach

- Is not generally equitable – the users who benefit from the assets providing utility service are not responsible for the total costs of the asset providing that service.
- Inflates the amount of future depreciation expense, which will compound with each generation of asset replacement. Ultimately the final users of the system will be faced with an exponential amount of costs of removal for investment that they receive no benefit from.
- There is increased utility risk that cost variances will be to the account of the utility and not recoverable from ratepayers.

Q11. PLEASE DISCUSS THE USE OF TRUST FUNDS OR SECURITIZATION TO PROVIDE FOR FUTURE COSTS OF REMOVAL/RETIREMENT.

These methods involve the creation of an external fund for the purpose of financing a future defined obligation (such as costs of removal), with customers paying a surcharge on current use to fund the future obligation. Contributions to the fund are invested with earnings from the return on the investment in the trust fund adding to fund levels. In many jurisdictions, the establishment of a trust fund may require enabling legislation. Once allowed by statute, the utility requests regulatory approval to establish the trust fund, with proposed governance of all aspects of fund management including a periodic review of funding levels and the investment portfolio.

In the circumstance of a trust fund, establishment of the fund or funds will involve a transfer of the Accumulated Depreciation associated with the funding that has occurred to date. The transfer amount requires an assessment of alternative tax treatments accorded to potential trust vehicles. The trust fund(s) are supported by ratepayer charges that are invested in equities and bonds by a fund management entity. Periodic regulator review of the funding status of the fund balance related to the required level of funding incorporating current estimates of future required expenditures – and investment performance. Upon retirement of assets, the funds are disbursed to supplement underfunded Cost of Removal balances.

In the circumstances of use of Securitization, legislation authorizes establishment of a Special Purpose Entity (SPE) for a dedicated purpose (e.g., recovery of future costs of removal requirements). The legislation typically includes language that protects bondholders from regulatory risk. The regulator issues an order with adequate protections to enable low-cost financing, after finding that there is a NPV benefit to customers. The utility issues bonds to finance early retirement of assets. Undepreciated asset balances are removed from utility rate base and no longer earn a return. Ratepayers are responsible for a customer charge that may be subject to periodic true-ups to ensure that it is sufficient to meet bond obligations by a non-bypassable surcharge over the term of the bonds that is passed through the SPE to bondholders. The customer charge may be subject to periodic true-ups to ensure that it is sufficient to meet bond obligations.

<u>Advantages of these approaches</u>

- Provide a means to recover costs from ratepayers that benefit from the assets during the life of the asset.
- Provides a method for the ratepayer contributions to grow within the trust resulting in lower amounts of customer contributions as compared to other methods.

- In case of Securitization, the utility is provided with a near-term infusion of cash to offset the seeding of the trust funds.

Disadvantages of these approaches

- Regulatory oversight can present an administrative burden
- Securitization tends to reduce future utility earnings unless it is accompanied by re-investment opportunities (e.g., assets that support clean energy).
- Credit ratings are sensitive to increasing capital costs associated with investments to build resiliency against and respond to climate change events (e.g., California wildfires).
- There are consequences to an over reliance on securitization, including deterioration of credit metrics, reduced financing flexibility and crowding out new rate base investments.

III. CONCENTRIC RECOMMENDATION

Q12. PLEASE OUTLINE THE OBJECTIVES THAT SHOULD BE CONSIDERED IN THE REVIEW OF VARIOUS OPTIONS FOR THE INCLUSION OF FUTURE REMOVAL/RETIREMENT EXPENDITURES INTO THE DEPRECIATION RATE CALCUATIONS.

The available options should be considered in light of the following principles

- Alignment and matching of the depreciation expense to the rate base providing used and useful service;
- Ability of the method to respond to changes in the cost of removal estimates;
- Ability to deal with the impacts of inflation;
- Impact on the revenue requirement;
- To ensure the future cost requirements are adequately provided for;
- Provide for a smoothed methods of Cost of Removal/Retirement recovery; and
- Regulator acceptance.

Q13. PLEASE PROVIDE A COMPARISON OF EACH OF THE ALTERNATIVE OPTIONS TO THE OVERALL OBJECTIVE AS DESCRIBED ABOVE.

The following table provides a comparative analysis of each of the 5 options to the overall principles identified above as they relate to the specific circumstances of BC Hydro at this time. Each option has been assigned a comparative ranking of 1 through 5, based on the comparative ranking of the options as compared to each other option. A ranking of 1 would indicate the best compliance of the 5 options, whereas a ranking of 5 indicates the worst ranking of the specific option as compared to the other options.

SUMMARY OF COMPLIANCE OF EACH OPTION TO THE OVERALL OBJECTIVES

Option / Principle	Traditional Method	Constant Dollar Net Salvage (CDNS)	Expense Cost of Removal as incurred	Capitalizing Cost of Removal as an Installation cost of replacement Assets	Trust Funds and Securitization Methods
1. Matching depreciation expense to used and useful rate base	1	2	4	5	3
2. Ability to respond to changes in Cost of Removal estimates	3	2	1	4	5
3. Ability to deal with the impacts of inflation	3	1	4	5	2
4. Impact on the revenue requirement	3	2	5	4	1
5. To ensure the future cost of removal/retirement requirements are adequately provided for	1	2	4	5	3
6. Provides for a smoothed method	2	3	5	4	1
7. Regulator Acceptance	1	5	2	4	3
Total Ranking	**14**	**17**	**25**	**31**	**17**

Q14. ARE THERE ANY DIFFERENCES IN UNDERLYING REGULATORY PRINCIPLES BETWEEN THE METHODS?

Yes. The above methods can be categorized into two groups, namely, the methods that provide for the future costs of removal/retirement on a retrospective rate making approach and those that recover the funding requirement with a prospective rate making approach.

Retrospective ratemaking approaches to the recovery of costs of removal address costs of removal after the retirement event has occurred and the amount to be recovered is known. A "pay-as-you-go" or "capitalize to the cost of the replacement asset" model does not address concerns related to customer bill impacts. Utilities and regulators often prefer to smooth out large bill impacts either by using a future deferral/regulatory asset approach or recovering a relatively large unfunded cost of removal over a longer period through securitization.

Prospective ratemaking tools anticipate future cost recovery challenges and are designed to build up a balance by collecting funds from current ratepayers that can be applied in later years. Nuclear decommissioning trust funds are an example that collects funds from customers while the plant is operating to fund a future – and large – investment to decommission the plant after it shuts down. Depreciation expense methodologies address a similar goal by accurately reflecting the future "Cost of Removal" through either the Traditional or CDNS methods described above, when calculating depreciation rates.

Q15. WHAT ARE THE ADVANTAGES OF ONE RATE MAKING APPROACH OVER THE OTHER IN THE SPECIFIC CIRCUMSTANCES OF RECOVERY OF COSTS OF REMOVAL?

The prospective ratemaking approaches better comply with the regulatory principle that cost recovery of all investment related to an asset should occur over the period in which the asset is in used and useful service. For example, the Federal Energy Regulatory Commission (FERC) prescribes that:

> *Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance.*[2] [emphasis added]

---

[2] Federal Energy Regulatory Commission -Part 201- Uniform System of Accounts Prescribed for Electric Companies Subject to the Provisions of the Electric Act Definitions

The FERC also describes the service value to be recovered as:

> *Service value means the difference between original cost and net salvage value of electric plant.*[2]

The accounting concepts of matching revenues to the related expenses within the same accounting period also lends support to the prospective approach as it better aligns the return on rate base to the depreciation expense component of the revenue requirement.

The most significant advantage of the retrospective approaches is the fact that the amount to be recovered is known. However, the true-up mechanisms used with the prospective methods achieves a similar result by trueing up of the accumulated depreciation accounts.

Q16. PLEASE OUTLINE YOUR RECOMMENDATION GIVING CONSIDERATION TO THE SPECIFIC CIRCUMSTANCES OF BC HYDRO.

When considering both the ranking of the various options to the identified principles, and the preference of most regulators to adopt a prospective rate making approach, I find the Traditional Method to be most appropriate for BC Hydro at this time.

The recommended Traditional Approach is consistent with the recent approvals by the BCUC for the use of this same Traditional Approach for FortisBC Inc., FortisBC Energy, and Pacific Northern Gas. It is also the most accepted method of recovering future costs of removal by regulators throughout North America.

IV. IMPLEMENTATION APPROACH

Q17. PLEASE DESCRIBE YOUR RECOMMENDED METHOD FOR THE IMPLEMENTATION OF THE RECOVERY OF FUTURE COSTS OF REMOVAL/RETIREMENT THROUGH THE TRADITIONAL METHOD.

Section 3-4 of the Concentric Depreciation Study report describes the need to develop the net salvage percentages at an aggregated functional group level, with each aggregated function group being composed of the specific accounts within the functional group that would be expected to incur future costs of removal or retirement. Additionally, any accounts that have a current Asset Retirement Obligation (ARO) were excluded in order to ensure that there is no overlapping of recovery of the retirement costs.

The recovery of the future costs of removal on a prospective ratemaking approach through use of the Traditional Method will eliminate the need for the currently estimated revenue requirement inclusion of the current period cost of removal. As such, the impact of implementation of the Traditional Approach will be partially offset by the exclusion of the pay as you go estimates currently being included in the revenue requirement. However, it is recognized that the implementation of the Traditional Method will have a revenue requirement impact, even after consideration that the "Pay as you go" amounts are eliminated. As such, a phase-in period is often considered to be appropriate when the Traditional Method is introduced.

A phasein to complete implementation of the Traditional Method as soon as practicable best aligns with the objectives outlined in this Report. However, implementation should also consider the need to mitigate rate impacts. As such, in my opinion, a period of complete implementation covering a period of up to 10 years is recommended.

Q18. DOES THIS CONCLUDE YOUR REPORT?

Yes.

LARRY E. KENNEDY, CDP

Senior Vice President

Mr. Kennedy has been in the pipeline, electric, gas utility and municipal infrastructure business for 40 years. As Senior Vice President, Concentric Advisors, ULC, Mr. Kennedy has provided professional consulting services to gas and electric utilities including generation facilities (including nuclear facilities), and high voltage transmission lines, large diameter transmission pipelines, railway systems and municipally owned utility systems. Previously, Mr. Kennedy was with Gannett Fleming Canada ULC, for over 17 years, where he was responsible for completing depreciation studies and provided advice related to large capital program spending and controls for many regulated North American utilities. Mr. Kennedy was also employed by Interprovincial Pipelines Limited (now Enbridge Pipelines) for 15 years in several plant accounting and regulatory positions and with Nova Gas Transmission Pipelines (now TC Energy) for three years as a Depreciation Specialist.

Mr. Kennedy has provided expert witness testimony related to depreciation, capital accounting issues, utility valuation, and property tax issues before several North American regulatory bodies. Mr. Kennedy has completed numerous seminars and all courses offered by Depreciation Programs, Inc. Mr. Kennedy is a member of the teaching faculty of the Society of Depreciation Professionals ("SDP") and has presented depreciation and capital accounting related topics to the SDP, Canadian Electric Association, Canadian Gas Association, Canadian Property Taxpayers Association, Alberta Utilities Commission, British Columbia Utilities Commission and the Canadian Energy Pipeline Association. Mr. Kennedy is a past Society of Depreciation Professionals President.

PERSONAL INFORMATION

- Diploma, Applied Arts - Business Administration, Northern Alberta Institute of Technology, 1978
- Member, Society of Depreciation Professionals
- Certified Depreciation Professional

EXPERIENCE

Representative Project Experience

- Alberta Departments of Energy and Forestry and Agriculture: Detailed toll comparison and valuation models were developed to provide a comparison of the toll fairness of each of the Provinces Rural Electrification Associations ("REA") to the comparable Investor Owned Utilities ("IOU") for the 32 REA's currently operating in Alberta. In addition to providing a toll comparison of the REA and IOU, a fair market valuation for each of the REA's was also prepared. The final report of the toll compatibility and specific valuations were submitted to the Alberta Department of Energy and the Alberta Department of Forestry and Agriculture. Mr. Kennedy was the Responsible Officer on this project.
- Alliance Pipeline L.P. A number of depreciation studies have been completed by Mr. Kennedy for both the Canadian and US assets of Alliance Pipelines. The most recent

studies completed in 2012 for Submission to the National Energy Board of Canada and to the Federal Energy Regulatory included operational discussions related to the gas transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the inclusion of an Economic Planning Horizon.

- AltaGas Utilities Inc.: A number of depreciation studies have been completed, which included the assembly of basic data from the Company's accounting systems, statistical analysis of retirements for service life and net salvage indications, discussions with management regarding the outlook for property, and the calculations of annual and accrued depreciation. The studies were prepared for submission to the Alberta Energy and Utilities Board ("Board"). Mr. Kennedy has appeared before the Alberta Utilities Commission on behalf of AltaGas on a number of occasions.
- AltaLink LP: An initial study was developed for submission to the Alberta Utilities Commission ("AUC") in 2002. The study included the estimation of service life characteristics, and the estimation of net salvage requirements for all electric transmission assets. A net salvage study and technical update was also filed with the Board in 2004. Since 2004, additional depreciation studies were filed in 2005, 2010 and 2012, 2016 and 2018. The 2010, 2012, 2016 and 2018 studies included a number of provisions in order to ensure compliance to Alberta's Minimum Filing Requirements for depreciation studies and for compliance to the International Financial Reporting Standards. These studies also specifically analyzed the pace of technical change in the Alberta Electric system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.
- ATCO Electric: Studies have included the development of annual and accrued depreciation rates for the electric transmission and distribution systems for the Alberta assets of ATCO Electric, in addition to the generation, transmission, and distribution assets of Northland Utilities Inc. (NWT) and the distribution assets of Northland Utilities (Yellowknife) Inc. The ATCO Electric studies were submitted to the AUC for review, while the NWT and Northland Utilities (Yellowknife) Inc. studies were submitted to the Northwest Territories Utilities Board and Yukon Electric Company Limited (YECL) was submitted to the Yukon Public Utilities Board. These studies also specifically analyzed the pace of technical and recently have specifically considered the impacts of early retirements caused by storms and forest fires.
- ATCO Gas: Studies were prepared in 2010 and 2018 which were the subject of a review by the AUC. Elements of all of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. These studies also specifically analyzed the pace of technical change in the Alberta Gas system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.
- Montana-Dakota Utilities Co.: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets.

The study and associated expert testimony were submitted to the Montana Public Service Commission in 2018. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook and the estimation of the retirement of generation facilities due to environmental legislation and estimation of net salvage requirements.

- Great Plains Natural Gas Co.: Annual updates of depreciation rates and net salvage requirements were calculated and submitted to the Minnesota Department of Commerce in both 2017 and 2018.
- Centra Gas Manitoba, Inc.: The study included development of annual and accrued depreciation rates for all gas plant in service. Elements of the study included a field inspection of metering and compression facilities, service buildings and other gas plant; service life analysis for all accounts using the retirement rate analysis on a combined database developed from actuarial data and data developed through the computed method; discussions with management regarding outlook; and the estimation of net salvage requirements. A similar study was completed in 2006, 2011, and 2015. The 2011 and 2015 studies were the subject of a review by the Manitoba Public Utilities Board in 2012 and 2016. Mr. Kennedy has also consulted on issues regarding International Financial Reporting Standards ("IFRS") compliance and required componentization.
- Enbridge Gas Distribution Inc.: Full and comprehensive depreciation studies have been completed in 2009 and 2011. The 2009 study also included review of the company's gas storage operations. Both studies included the development of annual and accrued depreciation rates for all depreciable natural gas distribution, transmission and general plant assets. Elements of the studies included the service life analysis for all accounts using the computed mortality method of analysis, discussion with management regarding outlook and the estimation of net salvage requirements. Studies were prepared for submission to the Ontario Energy Board.
- Mr. Kennedy has also completed an allocation of the accumulated depreciation accounts into the amounts related to the recovery of original cost and the amounts recovered in tolls for the future removal of assets currently in service. The allocations were determined as of December 31, 2009 and were deemed by the company's external auditors to be in conformance with proper accounting standards and procedures. In 2013, a review of the reserve required for the future removal of assets currently in service was undertaken by Mr. Kennedy. The results of the review were summarized in evidence presented by Mr. Kennedy to the Ontario Energy Board.
- ENMAX Power Corporation: Studies have included the development of annual and accrued depreciation rates for all depreciable electric transmission assets. Elements of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. Studies were prepared for submission to the Alberta Department

of Energy and more recently for submission to the Alberta Energy and Utilities Board. Similar studies have also been completed for submission for the ENMAX Electric Distribution assets for submission to the AUC. The ENMAX distribution asset assignments also included an extensive asset verification project where the plant accounting and operational asset records were verified to the field assets actually in service.

- Fortis Group of Companies: Studies have included the development of annual and accrued depreciation rates for the electric distribution assets in Alberta and for the generation, transmission, and distribution assets in British Columbia. The FortisBC Inc. studies were completed and filed with the British Columbia Utilities Commission ("BCUC") in 2005, 2010, 2011 and 2018 encompassing both the FortisBC electric and natural gas companies. FortisAlberta Inc. studies were completed in 2004 (updated in 2005), 2009 and 2010. Elements of the studies included the development of average service lives using the retirement rate method of analysis, development of net salvage estimates, compliance with IFRS, and the determination of appropriate annual accrual and accrued depreciation rates. The most recent studies also specifically analyzed the pace of technical change in the Electric systems, and specifically considered the impacts of retirements, system modernization and technical enchantments to the assets.

- International Financial Reporting Standards ("IFRS"): Mr. Kennedy has been retained by numerous clients encompassing most Canadian Provinces and Territories. The assignments included the review of company's assets and depreciation practices to provide opinion on the compliance to the IFRS. The assignments have also included the issuance of opinion to the External Auditors of Utilities to comment on the manner in which the Utilities can minimize differences in the regulatory ledgers and the accounting records used for financial disclosure purposes. Mr. Kennedy has also presented to the Canadian Electric Association, the Society of Depreciation Professionals, the Canadian Energy Pipeline Association and to the BCUC on this topic.

- Mackenzie Valley Pipeline Project: This assignment included the review of the proposed depreciation schedule for the proposed Mackenzie Valley Pipeline. The review included a discussion of the policies used by the company and the depreciation concepts to be included in a depreciation schedule for a Greenfield pipeline. The review was supported through appearance at the oral public hearings before the National Energy Board of Canada ("NEB").

- Manitoba Hydro: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study was submitted to the Manitoba Public Utilities Board. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook and the estimation of net salvage requirements. A similar study was also completed in 2006 and in 2011. The 2011 depreciation study was the subject of a review by the Manitoba Public Utilities Board in 2012. Mr. Kennedy has also consulted with Manitoba Hydro on issues regarding IFRS compliance and required componentization.

- National Grid USA Service Company Limited: A depreciation study was completed in 2020 for the National Grid High Voltage Direct Current (HVDC) electric interstate transmission line. The study included consideration of the average service life of the system components, the level of components of the system and the compliance of the recommended componentization to the FERC Uniform System of Accounts. The resultant study was used by the company in filings with the Federal Energy and Regulatory Commission (FERC).
- New Brunswick Power: Mr. Kennedy completed a comprehensive depreciation review of the electric generation (including the nuclear facilities), transmission, distribution and general plant assets. The review, which was prepared for submission to the New Brunswick Public Utilities Board, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report.
- Newfoundland and Labrador Hydro (NALCOR): Mr. Kennedy developed comprehensive depreciation studies that included the development of depreciation policy and rates for NALCOR. The studies provided a significant review of the previous depreciation policy, which included use of a sinking fund depreciation method and provided justification for the conversation to the straight-line depreciation method. The study, which was prepared for submission to the Newfoundland and Labrador Utilities Commission, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report for submission in a General Tariff Application. Additional studies were also completed in 2008 and 2010. The 2010 and 2017 studies were the subject of Regulatory Review in 2012 and 2019.
- Ontario Power Generation: Assignments have included a review of the Depreciation Review Committee process completed in 2007. This review provided recommendations for enhanced internal processes and controls in order to ensure that the depreciation expense reflects the annual consumption of service value. Additionally, full assessments of the lives of the regulated assets of the company's electric generation hydro and nuclear plants were completed in 2011 and 2013 and were submitted to the Ontario Energy Board for review.
- TransCanada Pipelines Limited - Alberta Facilities: The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Alberta Energy and Utilities Board, incorporated the concepts of time-based depreciation for gas transmission accounts and unit-based depreciation for

gathering facilities. The data was assembled from two different accounting systems and statistical analysis of service life and net salvage were performed. For gathering accounts, the assignment included the oversight of the development of appropriate gas production and ultimate gas potential studies for specific areas of gas supply. Field inspections of gas compression, metering and regulating, and service operations were conducted. Studies were completed in 2002 and 2004, 2007, 2009 and 2012, 2015, and 2018.

- TransCanada Pipelines Limited - Mainline Facilities: The study prepared for submission to the NEB included the development of annual and accrued depreciation rates for gas transmission plant east of the Alberta - Saskatchewan border. Elements of the study included a field inspection of compression and metering facilities, service life and net salvage analysis for all accounts. The study was completed in 2002 and was supported through an appearance before the NEB. Study updates have been completed in 2005, 2007, 2009 and an additional full and comprehensive study was completed in 2011, and 2017. The 2011 study was fully supported through an appearance before the NEB in 2012.

- Viking Gas Transmission Company - The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Federal Energy and Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons.

Designations and Professional Affiliations

- Society of Depreciation Professionals -Certified Depreciation Professional
- Society of Depreciation Professionals (former President)

EVIDENCE ENTERED INTO PROCEEDINGS IN THE UNITED STATES

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2015	Alliance Pipeline LP	Alliance Pipeline LP	Federal Energy and Regulatory Commission	Docket No. RP15-1022
2019	Viking Gas Transmission Company	Viking Gas Transmission Company	Federal Energy Regulatory Commission	RP19-1340
2020	National Grid USA Service Company Limited	National Grid USA Service Company Limited	Federal Energy Regulatory Commission	Pending
2018	Great Plains Natural Gas Co.	Great Plains Natural Gas Co.	Minnesota Department of Commerce	Annual Depreciation Filing
2018	Montana-Dakota Utilities	Montana-Dakota Utilities	Montana Public Service Commission	Docket D2019.9
2019	Great Plains Natural Gas Co	Great Plains Natural Gas Co	Minnesota Department of Commerce	Annual Depreciation Filing
2020	Cascade Natural Gas Corporation	Cascade Natural Gas Corporation	Oregon Public Utility Commission	Pending
2020	Missouri-American Water Company	Missouri-American Water Company	Missouri Public Service Commission	WR-2020-0344
2020	Great Plains Natural Gas Co	Great Plains Natural Gas Co	Minnesota Department of Commerce	Annual Depreciation Filing
2020	Commonwealth Edison Company	Commonwealth Edison Company	State of Illinois – Illinois Commerce Commission	Docket 20-0393
2021	Intermountain Gas Company	Intermountain Gas Company	Idaho Public Utilities Commission	Case No. INT-21-01
2021	Midwestern Gas Transmission Company	Midwestern Gas Transmission Company	Federal Energy Regulatory Commission	RP21-525-000
2021	Consolidated Edison of New York	Consolidated Edison of New York	New York State Public Service Commission	19-G-0066

EVIDENCE ENTERED INTO PROCEEDINGS IN CANADA

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
1999	ENMAX Power Corporation	Edmonton Power Corporation	Alberta Energy and Utilities Board	980550
2000	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	Decision 2002-43

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2001	City of Calgary	ATCO Pipelines South	Alberta Energy and Utilities Board	2000-365
2001	City of Calgary	ATCO Gas South	Alberta Energy and Utilities Board	2000-350
2001	City of Calgary	ATCO Affiliate Proceeding	Alberta Energy and Utilities Board	1237673
2001	ENMAX Power Corporation	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2002	Centra Gas British Columbia	Centra Gas British Columbia	British Columbia Utilities Commission	N/A
2002	ENMAX Power Corporation	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2003	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1279345
2003	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2003	City of Calgary	ATCO Pipelines	Alberta Energy and Utilities Board	1292783
2003	City of Calgary	ATCO Electric-ISO Issues	Alberta Energy and Utilities Board	N/A
2003	City of Calgary	ATCO Gas	Alberta Energy and Utilities Board	1275466
2003	City of Calgary	ATCO Electric	Alberta Energy and Utilities Board	1275494
2003	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2003	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-1-2002
2004	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1305995
2004	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1336421
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Energy and Utilities Board	1306819
2004	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2004	NOVA Gas Transmission Limited	NOVA Gas Transmission Limited	Alberta Energy and Utilities Board	1315423

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2004	Westridge Utilities Inc.	Westridge Utilities Inc.	Alberta Energy and Utilities Board	1279926
2005	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1378000
2005	ATCO Electric	ATCO Electric	Alberta Energy and Utilities Board	1399997
2005	ATCO Power	ATCO Power	Municipal Government Board of Alberta	N/A
2005	British Columbia Transmission Corporation	British Columbia Transmission Corporation	British Columbia Utilities Commission	N/A
2005	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation – Transmission	Alberta Energy and Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation – Distribution Assets	Alberta Energy and Utilities Board	1380613
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	1371998
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	N/A
2005	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A
2005	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2005	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	New Brunswick Board of Commissioners of Public Utilities	N/A
2005	Northland Utilities (NWT) Inc.	Northland Utilities (NWT) Inc.	Northwest Territories Utilities Board	N/A
2005	Northland Utilities (Yellowknife) Inc.	Northland Utilities (Yellowknife) Inc.	Northwest Territories Utilities Board	N/A
2005	NOVA Gas Transmission Ltd.	NOVA Gas Transmission Ltd.	Alberta Energy and Utilities Board	1375375
2005	City of Red Deer	City of Red Deer Electric System	Alberta Energy and Utilities Board	1402729
2005	Yukon Energy Corporation	Yukon Energy Corporation	Yukon Utilities Board	N/A
2006	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1456797
2006	BC Hydro	BC Hydro	British Columbia Utilities Commission	N/A
2006	Imperial Oil Resources Ventures Limited	McKenzie Valley Pipeline Project	National Energy Board of Canada	GH-1-2004

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2007	Enbridge Pipelines Limited	Enbridge Pipelines Limited	National Energy Board of Canada	RH-2-2007
2007	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Energy and Utilities Board	1514140
2007	Kinder Morgan	Terasen (Jet fuel) Pipeline Limited	British Columbia Utilities Commission	N/A
2008	ATCO Electric	Yukon Electrical Company Limited	Yukon Utilities Board	N/A
2008	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1553052
2008	City of Lethbridge Electric System	City of Lethbridge	Alberta Utilities Commission	N/A
2008	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1512089
2008	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2009	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	N/A
2009	Fortis Alberta Inc.	Fortis Alberta, Inc.	Alberta Utilities Commission	1605170
2010	ATCO Electric	ATCO Electric	Alberta Utilities Commission	1606228
2010	Enbridge Pipelines Limited· Line 9	Enbridge Pipelines Limited - Line 9	National Energy Board of Canada	N/A
2010	Gazifere	Gazifere	La Regie de L'Energie	R-3724-2010
2010	Kinder Morgan	Kinder Morgan	National Energy Board of Canada	N/A
2010	Pacific Northern Gas	Pacific Northern Gas	British Columbia Utilities Commission	N/A
2011	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	1606694
2011	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1606895
2011	ATCO Electric	Northland Utilities (NWT) Inc.	Northwest Territories Utility Board	N/A
2011	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1606822
2011	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Utilities Commission	1607159
2011	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	3698627
2011	GazMetro	GazMetro	La Regie de L'Energie	R-3752-2011
2011	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2011	Qulliq	Qulliq	Utilities Rates Review Council	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2011	SaskPower	SaskPower	Internal Review Committee	N/A
2011	TransAlta Utilities Corporation	TransAlta Utilities Corporation	Municipal Government Board of Alberta	N/A
2012	City of Red Deer	City of Red Deer	Alberta Utilities Commission	1608641
2012	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Ontario Energy Board	EB 2011-0345
2012	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	3698620
2012	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2013/2013 GRA
2012	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2012	Northwest Territories Power Corporation	Northwest Territories Power Corporation	Northwest Territories Public Utilities Board	N/A
2012	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-003 -2011
2013	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1608711
2013	lntraGaz Incorporated	lntraGaz Incorporated	La Regie de L'Energie	R-3807-2012
2013	Yukon Electrical Company Limited (YECL)	Yukon Electrical Company Limited (YECL)	Yukon Utilities Board	2013-2015 GRA
2014	Enbridge Gas Distribution	Enbridge Gas Distribution	Ontario Energy Board	EB-2012-0459
2014	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1609674
2015	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 3524
2015	EPCOR Distribution & Transmission	EPCOR Distribution & Transmission	Alberta Utilities Commission	Proceeding 20407
2015	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	N/A
2015	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A
2015	GazMetro	GazMetro	La Regie de L'Energie	N/A
2015	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2014/15 & 2015/16 GRA
2015	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2016	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 20272
2017	NALCOR	NALCOR	Newfoundland Public Utilities Board	Settled
2017	TransCanada Pipelines Limited – Mainline Facilities	TransCanada Pipelines Limited – Mainline Facilities	National Energy Board of Canada	RH-1-2018
2017	TransCanada Pipelines Limited – NGTL Facilities	TransCanada Pipelines Limited – NGTL Facilities	National Energy Board of Canada	RH-001-2019
2018	WestCoast Transmission System	WestCoast Transmission System	National Energy Board of Canada	Settled
2018	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 24195
2018	ATCO Gas	ATCO Gas	Alberta Utilities Commission	Proceeding 24188
2018	SaskEnergy Inc.	SaskEnergy Inc.	Saskatchewan Review Board	N/A
2018	SaskPower	SaskPower	Saskatchewan Review Board	N/A
2018	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	Proceeding 24161
2018	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 23848
2018	FortisBC Energy Inc.	FortisBC Energy Inc.	British Columbia Utilities Commission	N/A
2018	FortisBC Inc.	FortisBC Inc.	British Columbia Utilities Commission	N/A
2019	Capital Power Corporation	Capital Power Corporation	Municipal Government Board of Alberta	N/A
2019	TransAlta Corporation	TransAlta Corporation	Municipal Government Board of Alberta	N/A
2019	Trans Mountain Pipeline ULC	Trans Mountain Pipeline ULC	Canadian Energy Regulator	T260-2019-04-01
2019	NB Power	NB Power	New Brunswick Energy Utility Regulator	Pending
2019	ATCO Electric	ATCO Electric Transmission	Alberta Utilities Commission	Proceeding 24964
2020	Enbridge Pipelines Inc.	Enbridge Pipelines Inc.	Canada Energy Regulator (CER)	RH-001-2020
2020	Commonwealth Edison Company	Commonwealth Edison Company	State of Illinois – Illinois Commerce Commission	Docket 20-0393
2021	Ontario Power Generation	Ontario Power Generation	Ontario Energy Board	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2021	AltaLink L.P	AltaLink L.P	Alberta Utilities Commission	Proceeding 26059

BC Hydro
Power smart

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix U

F2022 to F2026 Electrification Plan
August 2021

PUBLIC

At this time, BC Hydro is filing Chapter 10 and Appendices U, V and W confidentially with the BCUC and can make this information available to registered interveners upon request and upon signing an appropriate undertaking to keep the information confidential. This information contains details that will be released through a public announcement expected to take place in mid to late September. Once that public announcement has been made, BC Hydro will provide notice to the BCUC so that these materials can be posted publicly and form part of the public record. Providing this information confidentially to the BCUC and interveners in advance of the public announcement will allow all parties to review the materials and draft information requests, on the same timeline as the rest of the Application.

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix V

Low Carbon Electrification Program

PUBLIC

At this time, BC Hydro is filing Chapter 10 and Appendices U, V and W confidentially with the BCUC and can make this information available to registered interveners upon request and upon signing an appropriate undertaking to keep the information confidential. This information contains details that will be released through a public announcement expected to take place in mid to late September. Once that public announcement has been made, BC Hydro will provide notice to the BCUC so that these materials can be posted publicly and form part of the public record. Providing this information confidentially to the BCUC and interveners in advance of the public announcement will allow all parties to review the materials and draft information requests, on the same timeline as the rest of the Application.

BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

Appendix W

Electric Vehicle Charging Stations as Prescribed Undertakings

PUBLIC

At this time, BC Hydro is filing Chapter 10 and Appendices U, V and W confidentially with the BCUC and can make this information available to registered interveners upon request and upon signing an appropriate undertaking to keep the information confidential. This information contains details that will be released through a public announcement expected to take place in mid to late September. Once that public announcement has been made, BC Hydro will provide notice to the BCUC so that these materials can be posted publicly and form part of the public record. Providing this information confidentially to the BCUC and interveners in advance of the public announcement will allow all parties to review the materials and draft information requests, on the same timeline as the rest of the Application.

BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

Appendix X

Fiscal 2021 Financial Schedules and Variance Explanations

BC Hydro
Power smart

BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission

Attachment 1 to Section 6

Fiscal 2021 Financial Schedules and Variance Explanations

Table of Contents

List of Tables

In sections 1 through 9, variance explanations are provided for actual gross amounts in fiscal 2021 compared to the F2020–F2021 RRA decision (**Decision**) amounts. Apart from domestic energy sales variances, all explanations are provided where variances between actual and Decision amounts are greater than 10 per cent, with a minimum variance threshold of $5 million. Domestic energy sales variance explanations are provided for each customer sector.

1 Domestic Energy Sales Variance Explanations (Schedule 14.0)

This section compares fiscal 2021 actual domestic energy sales amounts in GWh with the fiscal 2021 Decision.

Table 1 Fiscal 2021 Domestic Energy Sales Variances

		Schedule	F2021			
	(GWh)	Reference	Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Residential	14.0 L1	17,927	18,982	1,055	6%
2	Light Industrial and Commercial	14.0 L2	18,744	18,091	(653)	-3%
3	Large Industrial	14.0 L3	13,203	12,438	(765)	-6%
4	Other	14.0 L4:L10	2,066	1,628	(438)	-21%
5	**Total Domestic Energy Sales**	14.0 L11	**51,940**	**51,139**	(801)	-2%

Pursuant to Directive 4 of the Decision, this variance analysis includes an estimate of the extent of any variance that is attributed to and independent from the COVID-19 pandemic. Developing a precise estimate of load variance due to the COVID-19 pandemic is difficult because it involves a comparison of “what if” scenarios and forecasts, for which there are no measurable “after-the-fact” metrics. In particular, the COVID-19 Scenario A used to estimate the potential load impacts in fiscal 2021 was developed relative to the March 2020 Load Forecast whereas the F2020-F2021 RRA was based on the October 2018 Load Forecast, but then reduced by 2.6 per cent in accordance with the BCUC’s decision on that application. Since the March 2020 Load Forecast was a comprehensive forecast with updates to all input assumptions, the extent to which these assumptions differ from assumptions underpinning the F2020-F2021 RRA make it difficult to attribute variances due to the pandemic relative to the October 2018 Load Forecast.

For the purpose of responding to Directive 4, BC Hydro applied a simplified approach. We compared fiscal 2021 actual energy (GWh) consumption against fiscal 2020 actual consumption by major customer group. We then compared those differences to the net effect of COVID-19 Scenario A load impacts on the March 2020 Load Forecast for fiscal 2021. This comparison indicates that the differences between fiscal 2021 actuals and fiscal 2020 actuals are similar to the net effect of the assumed load declines reflected in the COVID-19 Scenario A on the March 2020 Load Forecast.

Following this, we assessed the variance results against our typical variance factors such as residential account growth, temperature, and specific large industrial account information to determine whether any variances can be clearly attributed to factors other than the COVID-19 pandemic.

Overall, actual domestic energy sales in fiscal 2021 were 801 GWh (or 2 per cent) lower than the fiscal 2021 Decision. This was due to:

- Line 1 - Actual residential sales were 1,055 GWh (or 6 per cent) higher than the fiscal 2021 Decision. Variances in residential sales are driven by three main factors: electricity sales per account (use per account), temperature, and number of accounts. In fiscal 2021, the residential sales variance was driven primarily by higher than expected use per account. Higher use per account variance can be driven by many different factors. While the exact drivers in this case are not known, the likely primary driver is the COVID-19 pandemic, which saw residential customers spend more time at home, working from home, and studying from home, resulting in higher consumption. The number of accounts was slightly favourable. The total number of residential accounts was 10,600 (less than 1 per cent) higher than plan and did not contribute significantly to the sales variance. There was a small offsetting variance for temperature, which was slightly unfavourable. Temperatures were close to normal, with warmer temperatures in December and January offset by colder temperatures in February and several other months of the year.

Actual fiscal 2021 sales are higher than fiscal 2020 actual sales and both the October 2018 and March 2020 Load Forecast sales expectations for fiscal 2021. Actual fiscal 2021 sales are directionally consistent with the COVID-19 Scenario A projection that residential sales would increase relative to the pre-pandemic March 2020 Load Forecast. While the net increase was not as large as projected, it was still higher relative to the fiscal 2021 Decision. Based on the above comparisons and consideration of temperature and account information, BC Hydro believes the positive fiscal 2021 sales variance can be largely attributed to the COVID-19 pandemic.

- Line 2 - Actual light industrial and commercial sales were 653 GWh (or 3 per cent) lower than the fiscal 2021 Decision. The commercial sector is comprised of a diverse group of business classes and lower energy consumption can generally be attributed to many different factors. For fiscal 2021 we expected the primary factor was closures and curtailments due to public health orders relating to the COVID-19 pandemic. To confirm this BC Hydro compared fiscal 2021 actual load to fiscal 2020 actual load. The business classes with the largest reduction in their load were offices, accommodations, food services, entertainment, recreation, shopping centers, and educational services. Actual fiscal 2021 sales are lower than fiscal 2020 actual sales and both the October 2018 and March 2020 Load Forecast sales expectations for fiscal 2021. Actual fiscal 2021 sales are directionally consistent with the COVID-19 Scenario A projection that sales would decline relative to the pre-pandemic March 2020 Load Forecast. While the net decline was not as large as projected, it was still lower relative to the fiscal 2021 Decision. Based on the above comparisons BC Hydro believes the negative fiscal 2021 sales variance is largely attributable to the COVID-19 pandemic.

- Line 3 - Actual large industrial sales were 765 GWh (or 6 per cent) lower than the fiscal 2021 Decision. Actual fiscal 2021 sales are lower than fiscal 2020 actual sales and both the October 2018 and March 2020 Load Forecast sales expectations for fiscal 2021. Actual fiscal 2021 sales are also consistent with COVID-19 Scenario A sales projections and underlying account assumptions. Based on the above comparison BC Hydro believes the negative fiscal 2021 sales variance is largely attributable to the COVID-19 pandemic.
- Line 4 – The original forecast for the Other customer sector was 1,650 GWh. As required by Directive 4 of BCUC Order G-246-20 BC Hydro increased the forecast by 25.2 percent for a revised forecast of 2,066 GWh in the fiscal 2021 Decision. Actual energy sales to the Other customer sector of 1,628 GWh were more consistent with the original forecast and were 438 GWh or 21 per cent lower than the revised forecast.

2 Domestic Revenue Variance Explanations (Schedule 14.0)

This section compares fiscal 2021 actual domestic revenue amounts with the fiscal 2021 Decision.

Table 2 Fiscal 2021 Domestic Revenues Variances

	($ million)	Schedule Reference	F2021 Decision	F2021 Actual	F2021 Diff	F2021 % Diff
			1	2	3=2-1	4=3/1
1	Residential	14.0 L12	2,140.4	2,210.2	69.8	3%
2	Light Industrial and Commercial	14.0 L13	1,905.9	1,830.4	(75.6)	-4%
3	Large Industrial	14.0 L14	852.2	761.7	(90.5)	-11%
4	Other	14.0 L15:L21	188.9	148.2	(40.7)	-22%
5	Subtotal	14.0 L22	5,087.4	4,950.4	(137.0)	-3%
6	Revenue from Deferral Rider	14.0 L23	-	0.0	0.0	0%
7	**Total Domestic Revenues**	14.0 L24	**5,087.4**	**4,950.4**	(137.0)	-3%

Actual domestic revenues in fiscal 2021 were $137.0 million (or 3 per cent) lower than the fiscal 2021 Decision. This was primarily due to:

- Line 1 - Residential revenue was $69.8 million (or 3 per cent) higher, driven by higher sales, as described in section 1 above, partially offset by COVID-19 Relief Program grants of $37.3 million;
- Line 2 - Light industrial and commercial revenue was $75.6 million (or 4 per cent) lower, mainly due to lower sales, as described in section 1 above, as well as $6.3 million of COVID-19 Relief program waivers provided to small business customers;
- Line 3 - Large industrial customer revenue was $90.5 million (or 11 per cent) lower due to lower sales, as described in section 1, as well as a lower average rate. The lower average rate was due to $13.3 million of lower demand charges provided as COVID-19 relief and due to a different mix of customer rates than planned; and
- Other revenue was $40.7 million (or 22 per cent) lower, mainly due to the lower sales described in section 1.

3 Cost of Energy Variance Explanations (Schedule 4.0)

This section compares fiscal 2021 actual sources of energy supply and cost of energy amounts with the fiscal 2021 Decision.

Table 3 Fiscal 2021 Sources of Supply

	(GWh)	Schedule Reference	F2021 Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Water Rentals	4.0 L1	44,522	49,796	5,275	12%
2	IPPs and Long-Term Commitments	4.0 L5	15,238	14,630	(608)	-4%
3	Market Electricity Purchases	4.0 L8	1,326	-	(1,326)	-100%
4	Natural Gas for Thermal Generation	4.0 L2	195	150	(46)	-23%
5	Surplus Sales	4.0 L9	(3,515)	-	3,515	-100%
6	System Imports	4.0 L10	-	999	999	0%
7	System Exports	4.0 L11	-	(9,082)	(9,082)	0%
8	Net Purchases (Sales) from Powerex	4.0 L12	(279)	-	279	-100%
9	Non-Integrated Area	4.0 L6	120	107	(13)	-11%
10	Exchange Net	4.0 L3	(250)	(355)	(105)	42%
11	**Total Sources of Supply**	4.0 L14	**57,357**	**56,245**	(1,112)	-2%

Actual fiscal 2021 sources of supply were 1,112 GWh (or 2 per cent) lower than the fiscal 2021 Decision. This was primarily due to:

- Lines 3, 5, 6, 7, and 8 – Higher net market exports[1] of 5,615 GWh driven by lower domestic load requirements and higher water inflows starting in late summer.

Partially offset by:

- Line 1 - Higher hydro generation of 5,275 GWh due to higher water inflows as mentioned above.

[1] The adoption of the 2020 TPA resulted in a change in the presentation of energy transactions (the sale and purchase of electricity) between BC Hydro and Powerex. The terms “Market Electricity Purchases” (Line 3 in Table 3), “Surplus Sales” (Line 5 in Table 3), and “Net Purchases (Sales) from Powerex” (line 8 in Table 3) were replaced by “System Imports” (line 6 in Table 3) and “System Exports” (line 7 in Table 3).

Table 4 Fiscal 2021 Cost of Energy Variances

	($ million)	Schedule Reference	F2021 Decision	F2021 Actual	F2021 Diff	F2021 % Diff
			1	2	3=2-1	4=3/1
	Heritage Energy					
1	Water Rentals	4.0 L15	323.2	333.2	10.0	3%
2	Natural Gas for Thermal Generation	4.0 L16	8.5	6.5	(2.0)	-24%
3	Domestic Transmission - Other	4.0 L17	24.4	25.5	1.1	5%
4	Non-Treaty Storage and Libby Coordination Agreements	4.0 L18	(11.7)	(49.9)	(38.1)	325%
5	Remissions and Other	4.0 L19	(26.7)	(42.0)	(15.4)	58%
6	**Subtotal**	4.0 L20	**317.7**	**273.3**	(44.4)	-14%
	Non-Heritage Energy					
7	IPPs and Long-Term Commitments	4.0 L21	1,410.8	1,404.0	(6.8)	0%
8	Non-Integrated Area	4.0 L22	30.2	26.0	(4.1)	-14%
9	Gas & Other Transportation	4.0 L23	2.5	5.3	2.7	107%
10	Water Rentals (Waneta 2/3)	4.0 L24	3.7	3.2	(0.5)	-13%
11	**Subtotal**	4.0 L25	**1,447.2**	**1,438.5**	(8.6)	-1%
	Market Energy					
12	Market Electricity Purchases	4.0 L26	43.7	0.0	(43.7)	-100%
13	Surplus Sales	4.0 L27	(165.1)	0.0	165.1	-100%
14	System Imports	4.0 L28	0.0	26.9	26.9	0%
15	System Exports	4.0 L29	0.0	(227.9)	(227.9)	0%
16	Net Purchases (Sales) from Powerex	4.0 L30	6.1	0.0	(6.1)	-100%
17	Domestic Transmission - Export	4.0 L31	17.0	11.6	(5.4)	-32%
18	**Subtotal**	4.0 L32	(98.4)	(189.4)	(91.0)	93%
19	**Total Gross Cost of Energy**	1.0 L1	**1,666.5**	**1,522.4**	(144.0)	-9%

Fiscal 2021 actual gross Cost of Energy was $144.0 million (or 9 per cent) lower than the fiscal 2021 Decision. This was primarily due to:

- Line 4 - Higher benefits associated with Non-Treaty Storage and Libby Coordination agreements of $38.1 million due to higher net water releases in the current year and more favourable prices during releases relative to forecast;
- Line 5 - Higher recoveries from remissions and other of $15.4 million due to higher water use planning remissions for the Bridge River System and John Hart Generating Station;

- Lines 12 to 16 – Lower Market Energy costs[2] of $85.7 million due to higher net market exports of 5,615 GWh (Lines 3,5,6,7 and 8 of Table 3 - Fiscal 2021 Sources of Supply) driven by lower domestic load requirements and higher inflows in fiscal 2021; and
- Line 17 – Lower domestic transmission costs of $5.4 million, reflecting the new method of allocation of point-to-point charges between BC Hydro and Powerex as a result of the 2020 Transfer Pricing Agreement (2020 TPA). In particular, there is no longer an hourly determination of whether hourly export quantities reflect domestic sales versus trade activity. The revised calculation reflects the principles of section 6.2 of the 2020 TPA to provide a reasonable allocation of the point-to-point transmission costs incurred by BC Hydro in respect of Powerex's trading activities.

Directive 5 of the BCUC's Decision on BC Hydro's Fiscal 2022 Revenue Requirements Application (BCUC Order No. G-187-21) directed BC Hydro to report on the historic actual system imports/exports divided into flexible and non-flexible (i.e., according to the format in the 2020 TPA). Table 5 provides the fiscal 2021 actual system imports/exports divided into flexible and non-flexible.

[2] The 2020 Transfer Pricing Agreement (2020 TPA) came into effect on April 1, 2020 as directed by Order in Council No. 172 (BC Reg 88/2021) and approved by the BCUC Order No. G-127-21. The adoption of the 2020 TPA resulted in a change in the presentation of energy transactions (the sale and purchase of electricity) between BC Hydro and Powerex. The terms "Market Electricity Purchases" (line 12 in Table 4), "Surplus Sales" (line 13 in Table 4), and "Net Purchases (Sales) from Powerex" (line 16 in Table 4) were replaced by "System Imports" (line 14 in Table 4) and "System Exports" (line 15 in Table 4).

Table 5 Fiscal 2021 Actual System Imports/Exports Divided into Flexible and Non-Flexible

	F2021 Actual	
	$ million	**GWh**
System Imports		
Non-Flexible imports	4.6	61
Flexible imports	22.3	938
Total System Imports	26.9	999
System Exports		
Non-Flexible exports	(12.5)	(1,182)
Flexible exports	(215.3)	(7,900)
Total System Exports	(227.9)	(9,082)
Net System Imports / (Exports)	**(201.0)**	**(8,083)**

4 Operating Costs and Provisions Variance Explanations (Schedule 5.0)

This section compares fiscal 2021 actual gross operating costs and provisions amounts with the fiscal 2021 Decision.

Table 6 Fiscal 2021 Operating Costs and Provisions Variances

	($ million)	Schedule Reference	F2021 Decision	F2021 Actual	F2021 Diff	F2021 % Diff
			1	2	3=2-1	4=3/1
1	Integrated Planning	5.0 L1	292.0	308.8	16.7	6%
2	Capital Infrastructure Project Delivery	5.0 L2	81.1	80.8	(0.3)	0%
3	Operations	5.0 L3	244.3	265.2	21.0	9%
4	Safety	5.0 L4	57.5	55.7	(1.8)	-3%
5	Finance, Technology, Supply Chain	5.0 L5	264.8	277.3	12.5	5%
6	People, Customer, Corporate Affairs	5.0 L6	111.1	121.3	10.2	9%
7	Other	5.0 L7	(244.4)	(273.4)	(28.9)	12%
8	**Base Operating Costs**	5.0 L8	**806.4**	**835.7**	29.4	4%
9	IFRS Ineligible Capitalized Costs	5.0 L9	192.5	192.5	-	0%
10	Waneta 2/3	5.0 L10	5.9	5.8	(0.0)	-1%
11	Customer Crisis Fund	5.0 L11	5.3	2.9	(2.4)	-45%
12	**Subtotal**	5.0 L12	**203.6**	**201.2**	(2.4)	-1%
13	Deferred Account Additions	5.0 L16	-	(0.0)	(0.0)	0%
14	Regulatory Account Additions	5.0 L27	125.4	91.8	(33.6)	-27%
15	**Subtotal**		**125.4**	**91.8**	(33.6)	-27%
16	**Total Gross Operating Costs**	5.0 L27	**1,135.4**	**1,128.7**	(6.6)	-1%
17	Net Provisions & Other	5.0 L41	95.4	110.7	15.3	16%
18	Regulatory Account Additions - Provisions & Other	5.0 L49	-	53.0	53.0	0%
19	**Total Gross Provisions & Other**	5.0 L50	**95.4**	**163.7**	68.3	72%
20	**Total Gross Operating Costs and Provisions**	1.0 L2	**1,230.8**	**1,292.4**	61.7	5%

Fiscal 2021 actual gross Operating Costs and Provisions were $61.7 million (or 5 per cent) higher than the fiscal 2021 Decision. Of this amount, $53.0 million (line 18 in Table 6 above) was related to higher regulatory account additions for provisions and other, $29.4 million (line 8 in Table 6 above) was related to higher base operating costs, and $15.3 million (line 17 in Table 6 above) was related to higher net provisions and other. These amounts were partially offset by $33.6 million (line 14 in Table 6 above) related to lower regulatory account additions for operating costs.

Variances of $53.0 million related to higher regulatory account additions for provisions and other and variances of $33.6 million related to lower regulatory account additions for operating costs, netting to $19.4 million were primarily due to:

- An increase in the Environmental Provisions Regulatory Account of $51.2 million due to an increase in the Polychlorinated Biphenyl (**PCB**) provision of $20.5 million and an increase in the Asbestos Remediation provision of $30.7 million. The provisions increased due to increases in forecast PCB and Asbestos remediation costs, partially offset by reductions in the present value of future expenditures due to increases in discount rates;
- An increase in the Project Write-Off Costs Regulatory Account of $16.4 million due to $9.3 million project write-offs attributable to fiscal 2020 that was recorded prospectively in fiscal 2021 in accordance with Directive 32 of the BCUC's Decision on the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (received in fiscal 2021) and $7.1 million project write-offs relating to fiscal 2021. Itemized project write-offs deferred to the Project Write-off Costs Regulatory Account can be found in F Appendix L of the Fiscal 2022 Revenue Requirements Application for fiscal 2020, and Appendix P of the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application for fiscal 2021; and
- Other variances, totalling $0.3 million.

Partially offset by:

- Lower than planned increase in the Demand-Side Management Regulatory Account of $17.6 million due to fewer industrial customers advancing incentive projects than planned, COVID-19 restrictions impacting program operations, and shifts in completion of low carbon electrification customer projects to other fiscal years;
- A decrease in the Storm Restoration Costs Regulatory Account of $14.2 million due to:
  - $10.0 million lower than planned expenditures for storm restoration. Planned storm restoration expenditures are based on a five-year average of actual

storm restoration costs. In fiscal 2021, BC Hydro experienced relatively less storm activity (fewer and less severe wildfires, windstorms, snow events) and accordingly, actual storm restoration costs were lower than plan.

- $4.2 million reduction attributable to fiscal 2020 that was recorded prospectively in fiscal 2021 in accordance with Directive 19 of the BCUC's Decision on the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (received in fiscal 2021) that increased the BCUC approved storm restoration cost plan by $4.2 million.

- Decrease in the Real Property Sales Regulatory Account of $10.9 million attributed to the fiscal 2020 amount that was recorded prospectively in fiscal 2021 in accordance with Directive 41 of the BCUC's on the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (received in fiscal 2021); and
- Decrease in the Post-Employment Benefit (**PEB**) Current Pension Costs Regulatory Account of $5.8 million due to the increase in the discount rate from 3.33 per cent in the fiscal 2021 Decision vs 3.83 per cent in the fiscal 2021 actuals.

Variances of $29.4 million related to base operating costs were primarily due to higher than planned personnel costs, including employees unable to charge to capital/maintenance work programs as a result of the COVID-19 social distancing measures BC Hydro put in place in March 2020, additional vegetation work and expenditures to support Mandatory Reliability Standards compliance requirements, partially offset by lower costs due to maintenance work not proceeding as planned as a result of the COVID-19 pandemic.

Variances of $15.3 million related to net provisions and other were primarily due to non-recoverable amounts.

5 Taxes Variance Explanations (Schedule 6.0)

This section compares fiscal 2021 actual taxes amounts with the fiscal 2021 Decision.

Table 7 Fiscal 2021 Taxes Variances

	($ million)	Schedule Reference	F2021 Decision	F2021 Actual	F2021 Diff	F2021 % Diff
			1	2	3=2-1	4=3/1
1	Grants in Lieu	6.0 L15	114.8	117.3	2.5	2%
2	School Taxes	6.0 L16	146.8	138.7	(8.0)	-5%
3	Waneta 2/3 Property Taxes	6.0 L17	0.6	0.8	0.2	25%
4	**Subtotal Before Regulatory Accounts**	6.0 L17	**262.2**	**256.8**	(5.4)	-2%
5	Deferred Account Additions	6.0 L	-	-	-	N/A
6	**Total Gross Taxes**	1.0 L3	**262.2**	**256.8**	(5.4)	-2%

Fiscal 2021 actual gross Taxes of $256.8 million were comparable to the fiscal 2021 Decision of $262.2 million.

6 Amortization Variance Explanations (Schedule 7.0)

This section compares fiscal 2021 actual amortization amounts with the fiscal 2021 Decision.

Table 8 Fiscal 2021 Amortization Variances

	($ million)	Schedule Reference	F2021 Decision	F2021 Actual	F2021 Diff	F2021 % Diff
			1	2	3=2-1	4=3/1
1	Amortization of Capital Assets	7.0 L5	904.5	905.6	1.2	0%
2	IPP Capital Leases	7.0 L7	90.1	90.1	-	0%
3	Other Leases	7.0 L8	3.4	4.1	0.6	18%
4	**Subtotal Before Regulatory Accounts**		**998.0**	**999.8**	1.8	0%
5	Deferred Account Additions	7.0 L10	-	(0.3)	(0.3)	0%
6	**Total Gross Amortization**	1.0 L4	**998.0**	**999.5**	1.6	0%

Fiscal 2021 actual gross Amortization of $999.5 million was comparable to the fiscal 2021 Decision amount of $998.0 million.

7 Finance Charges Variance Explanations (Schedule 8.0)

This section compares fiscal 2021 actual finance charges amounts with the fiscal 2021 Decision.

Table 9 Fiscal 2021 Finance Charges Variances

	($ million)	Schedule Reference	F2021 Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Sinking Fund Income	8.0 L9	(7.7)	(8.9)	(1.2)	15%
2	Long-Term Debt Costs	8.0 L10	851.5	821.5	(29.9)	-4%
3	Short-Term Debt Costs	8.0 L11	69.6	12.4	(57.2)	-82%
4	Interest Capitalized	8.0 L12	(242.6)	(225.9)	16.7	-7%
5	Other (Income) / Loss	8.0 L13	45.1	46.2	1.0	2%
6	IPP Capital Leases	8.0 L14	46.1	46.1	-	0%
7	Accretion - Non-Deferrable	8.0 L15	1.3	1.1	(0.2)	-19%
8	Non-Current PEB	8.0 L16	(42.2)	64.0	106.2	-252%
9	Other Leases	8.0 L17	1.0	1.4	0.4	37%
10	**Subtotal Before Regulatory Accounts**	8.0 L18	**722.0**	**757.8**	35.8	5%
11	Regulatory Account Additions	8.0 L7	21.3	(506.2)	(527.5)	-2477%
12	**Total Gross Finance Charges**	1.0 L5	**743.3**	**251.6**	(491.8)	-66%

Fiscal 2021 actual gross Finance Charges were $491.8 million (or 66 per cent) lower than the fiscal 2021 Decision. This was primarily due to:

- Line 3 - Lower short-term debt costs of $57.2 million due to lower interest rates and lower outstanding short-term debt balance; and
- Line 11 - Lower regulatory account additions of $527.5 million primarily due to an increase in the fair value of future debt hedges as a result of increases in forward interest rates. Gains on future debt hedges are offset by higher interest costs when the future debt is issued.

Partially offset by:

- Line 4 - Lower interest capitalized of $16.7 million due to lower work in progress balances eligible for interest during construction; and

- Line 8 - Higher non-current PEB costs of $106.2 million due to a lower liability discount rate for estimating pension plan income in actuals versus the expected long-term rate of return on pension plan assets used for the fiscal 2021 Decision.

8 Miscellaneous Revenue Variance Explanations (Schedule 15.0)

This section compares fiscal 2021 actual miscellaneous revenue amounts with the fiscal 2021 Decision.

Table 10 Fiscal 2021 Miscellaneous Revenue Variances

	($ million)	Schedule Reference	F2021 Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Amortization of Contributions	15.0 L1+L8+L12	63.1	64.3	1.2	2%
2	External OATT	15.0 L4	15.9	14.1	(1.8)	-11%
3	FortisBC Wheeling Agreement	15.0 L5	5.3	5.2	(0.1)	-1%
4	Secondary Revenue (MMBU, Secondary Use, Other)	15.0 L6+L11+L28	24.2	32.4	8.3	34%
5	Interconnections	15.0 L7	2.2	8.3	6.1	278%
6	Meter/Trans Rents & Power	15.0 L14	14.9	16.4	1.5	10%
7	Smart Metering & Infrastructure	15.0 L15	1.7	1.6	(0.1)	-5%
8	Diversion Net Recoveries	15.0 L16	0.1	0.1	(0.0)	-7%
9	Other Operating Recoveries	15.0 L17	4.6	4.0	(0.6)	-12%
10	Customer Crisis Fund Rider Revenue	15.0 L18	5.3	2.9	(2.4)	-45%
11	Waneta 2/3	15.0 L24	86.9	86.5	(0.4)	0%
12	Corporate General Rents	15.0 L26	3.8	2.8	(1.0)	-25%
13	Late Payment Charges	15.0 L27	8.1	7.8	(0.3)	-4%
14	NTL Supplemental Charge	15.0 L9	2.3	2.4	0.1	3%
15	Other (Income) / Loss	15.0 L2+L19+L29	5.4	7.3	1.9	35%
16	**Subtotal Before Regulatory Accounts**	15.0 L31	**243.6**	**256.1**	12.6	5%
17	Deferral Account Additions	15.0 L33	3.5	5.0	1.5	43%
18	**Total Gross Miscellaneous Revenue**	1.0 L7	**247.0**	**261.1**	14.1	6%

Fiscal 2021 actual gross Miscellaneous Revenue was $14.1 million (or 6 per cent) higher than the fiscal 2021 Decision. This was primarily due to:

- Line 4 - Higher secondary revenue of $8.3 million, primarily due to a number of factors including higher than planned third party projects for shared assets, new customer agreement rate structure and prior year settlements, higher than planned volume of scrap sales, and higher than planned number of house moves and temporary connections; and

- Line 5 - Higher interconnections of $6.1 million, primarily due to higher than planned project revenues from feasibility, system and facilities studies.

9 Summary of Inter-Segment Revenue Variance Explanations (Schedule 3.0)

This section compares fiscal 2021 actual inter-segment revenue amounts with the fiscal 2021 Decision.

Table 11 Fiscal 2021 Inter-Segment Revenue Variances

	($ million)	Schedule Reference	F2021 Decision	F2021 Actual	F2021 Diff	F2021 % Diff
			1	2	3=2-1	4=3/1
1	Powerex - Business Support Allocation	3.0 L1	(2.9)	(2.9)	-	0%
2	Mark to Market Losses (Gains)	3.0 L2	-	90.0	90.0	0%
3	Powerex PTP Charges	3.0 L3	(34.0)	(41.7)	(7.8)	23%
4	BC Hydro PTP Charges	3.0 L4	(35.0)	(30.4)	4.7	-13%
5	**Total Inter-Segment Revenue**	1.0 L8	**(71.9)**	**15.0**	86.9	-121%

Fiscal 2021 actual Inter-Segment revenues were $86.9 million (or 121 per cent) lower than the fiscal 2021 Decision due to higher mark to market losses (line 2 in Table 11 above) of $90.0 million related to transactions under the Transfer Pricing Agreement between BC Hydro and Powerex, and higher point-to-point transmission charges of $3.1 million (line 3 and 4 in Table 11 above), primarily due to an increase in the BC Hydro Open Access Transmission Rate (**OATT**) for fiscal 2020 resulting from the BCUC's Decision on BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (BCUC Order G-246-20). The market to market losses are fully offset in Powerex's net income and have no impact on BC Hydro's consolidated net income or to ratepayers.

10 Capital Expenditures and Capital Additions Variance Explanations

The following tables and discussion provide information on the variances between fiscal 2021 actual capital expenditures and capital additions compared to the fiscal 2021 Decision amounts in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application, which was based on a Currency Date of April 1, 2018.

On an annual basis, BC Hydro manages over 900 projects and programs in various phases. Capital expenditures and capital additions in a fiscal year are impacted by a number of factors that may give rise to variances from plan, including project progression and timing, potential changes in scope due to as-found equipment conditions or other factors to meet business requirements, and cost changes due to market conditions or other factors.

In addition, capital projects frequently take several years to complete, and any variances from plan in a particular year may be offset by project expenditures and additions in a subsequent year. The variances provided are against planned annual capital expenditures and additions and are not necessarily reflective of the total project cost. While year-over-year capital project cash flows may vary from annual plan amounts, overall BC Hydro is delivering its projects on budget as reported through BC Hydro's Service Plan Budget to Actual Cost performance metric.

Variances are provided for each main asset category in the tables below. The amounts presented in the tables in this section may not add due to rounding. The actual capital additions information has been presented using the same classification as the planned capital additions as presented in the tables in Chapter 6 of BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.

The COVID-19 pandemic has had an impact on the delivery of BC Hydro's capital investments in fiscal 2021, as projects and programs with construction or field work were required to incorporate new safety protocols which resulted in slowing or delaying aspects of the work. BC Hydro also made decisions to delay work to manage risk to the system in the event of a COVID outbreak. In this report we have identified significant costs and (or) schedule COVID-19 impacts known as of March 31, 2021 to the projects and programs in fiscal 2021 and provided variance explanations in each section below.

In general, explanations are provided where variances between actual and planned amounts are greater than 10 per cent, with a minimum variance threshold of $10 million.

10.1 Overall Capital Expenditures and Additions Variance Explanations

Table 12 and Table 13 below provide BC Hydro's fiscal 2021 capital expenditures and capital additions by main asset category.

Table 12 Fiscal 2021 Capital Expenditures Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Generation	435.5	300.0	(135.5)	-31%
Site C Project	1,535.5	1,725.0	189.5	12%
Transmission & Distribution	946.8	970.9	24.1	3%
Business Support				
Technology	56.0	90.8	34.8	62%
Properties	55.3	56.0	0.7	1%
Fleet	27.8	31.4	3.6	13%
Business Support - Other	47.2	23.4	(23.9)	-51%
Total Gross	**3,104.1**	**3,197.5**	**93.4**	**3%**
Less: Contribution in Aid	(148.4)	(195.7)	(47.3)	32%
Total	**2,955.7**	**3,001.8**	**46.1**	**2%**

Table 13 Fiscal 2021 Capital Additions Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Generation	297.0	102.6	(194.4)	-65%
Site C Project	189.4	220.9	31.5	17%
Transmission & Distribution	770.3	824.6	54.3	7%
Business Support				
Technology	75.5	164.9	89.4	118%
Properties	55.6	70.9	15.3	27%
Fleet	27.8	26.8	(1.0)	-4%
Business Support - Other	43.5	22.7	(20.8)	-48%
Total Gross	**1,459.1**	**1,433.4**	**(25.7)**	**-2%**
Less: Contribution in Aid	(165.8)	(180.7)	(14.9)	9%
Total	**1,293.2**	**1,252.7**	**(40.5)**	**-3%**

Fiscal 2021 capital expenditures were $93.4 million (or 3 per cent) above the Fiscal 2021 Decision, excluding contribution in aid, primarily because:

- The Site C project was $189.5 million above plan primarily due to acceleration of the main civil work to meet the river diversion milestone date and unplanned COVID-19 pandemic related costs to comply with the COVID-19 safety requirements, as discussed in section 10.6; and
- Technology was $34.8 million above plan due to scope changes and schedule extensions for various projects as discussed in section 10.5.

The increase in capital expenditures above was partially offset by the lower than planned Generation capital expenditures of $135.5 million, primarily due to schedule changes for various projects as discussed in section 10.2.

Fiscal 2021 capital additions were $25.7 million (or 2 per cent) below the fiscal 2021 Decision, excluding contribution in aid, primarily due to the following:

- Generation capital additions were below plan by $194.4 million, primarily due to schedule changes for various projects and delays which shifted the timing of placing certain assets in-service, as discussed in section 10.2.

The decrease in capital additions above was partially offset by the following:

- Technology was above plan by $89.4 million, primarily due to the Supply Chain Applications project (included in the Technology line) as the project in-service date was delayed which shifted the timing from fiscal 2020 to fiscal 2021. This delay was due to a schedule extension for the build and testing activities, as well as the delay in the project go-live training, in response to the COVID-19 pandemic;
- Transmission and Distribution capital additions were above plan by $54.3 million, primarily due to schedule changes for various projects and programs which shifted the timing of placing certain assets in-service, as discussed in section 10.3 and 10.4; and
- The Site C project was $31.5 million above plan primarily because the in-service of the outdoor portion of the Peace Canyon Gas Insulated Switchgear occurred in fiscal 2021 as discussed in section 10.6.

10.2 Generation Capital Expenditures and Additions Variance Explanations

Generation capital expenditures and capital additions in fiscal 2021 are presented in Table 14 and Table 15 below. Results exclude amounts for the Site C project, which are presented separately in section 10.6 below.

Table 14 Fiscal 2021 Generation Capital Expenditures Variances (excluding Site C Project)

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Hydroelectric Generation				
Growth	-	0.8	0.8	100%
Redevelopment / Rehabilitation	-	9.3	9.3	100%
Dam Safety	130.0	55.8	(74.2)	-57%
Sustaining - Other	361.1	222.1	(139.0)	-38%
Total Hydroelectric Generation	491.1	288.0	(203.1)	-41%
Total Non-Integrated Areas	5.0	4.7	(0.3)	-5%
Total Thermal Generation	4.5	7.2	2.7	61%
Less: Portfolio Risk Adjustment	(65.2)	-	65.2	-100%
Total Gross	**435.5**	**300.0**	**(135.5)**	**-31%**
Less: Contribution in Aid	-	-	-	-
Total	**435.5**	**300.0**	**(135.5)**	**-31%**

Table 15 Fiscal 2021 Generation Capital Additions Variances (excluding Site C Project)

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Hydroelectric Generation				
Growth	-	0.6	0.6	100%
Redevelopment / Rehabilitation	-	9.3	9.3	100%
Dam Safety	44.4	34.1	(10.3)	-23%
Sustaining - Other	315.3	57.5	(257.8)	-82%
Total Hydroelectric Generation	359.7	101.4	(258.3)	-72%
Total Non-Integrated Areas	5.8	1.1	(4.7)	-82%
Total Thermal Generation	6.1	0.1	(6.0)	-98%
Less: Portfolio Risk Adjustment	(74.6)	-	74.6	-100%
Total Gross	**297.0**	**102.6**	**(194.4)**	**-65%**
Less: Contribution in Aid	-	-	-	-
Total	**297.0**	**102.6**	**(194.4)**	**-65%**

Growth Capital

Fiscal 2021 capital expenditures and capital additions for Generation Growth Capital were comparable to the fiscal 2021 Decision.

Redevelopment/ Rehabilitation

Fiscal 2021 capital expenditures and capital additions were comparable to the fiscal 2021 Decision.

Dam Safety

Fiscal 2021 capital expenditures were $74.2 million (or 57 per cent) below the fiscal 2021 Decision. This was primarily because:

- The Comox - Puntledge Flow Control Improvements project was $14.9 million below plan because the design was delayed due to greater than anticipated level of design complexity as well as delays of planned site inspections due to the COVID-19 pandemic;
- The Strathcona Upgrade Discharge project was $12.1 million below plan because the design was delayed due to the complexity of gate reliability and seismic withstand requirements;
- The Terzaghi - Spillway Chute Access Improvement project was $10.8 million below plan because of schedule delays in finalizing the Conceptual Design to appropriately balance worker risk, overall cost, and long-term maintenance;
- The W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates project was $9.8 million below plan because the project was delayed due to the addition of scope to design new stoplogs which were required to facilitate the project work;
- The John Hart Dam Seismic Upgrade project was $6.6 million below plan because design activities were completed over a longer time period, with a lower rate of spend than was assumed at the time the Plan was established. More detailed bottom up planning was completed after the Plan was established which resulted in a longer design schedule and a lower rate of spend than was assumed in the Plan;

- The Various Sites - Reservoir Booms Replacement was $5.1 million below plan because the project was initiated later than originally contemplated due to extended project planning and scheduling;
- The W.A.C. Bennett Dam Spillway Gate Upgrade project was $4.1 million below plan because of contractor delays in finalizing a contract and execution of the work;
- The Alouette Improve Headworks & Surge Tower Seismic Stability project was $4.1 million below plan because of a delay in completing the Identification Phase due to prolonged engagement and consultation with Indigenous groups and stakeholders;
- The Alouette - Environmental Flow Discharge Upgrade and LLO Sealing project was $2.2 million below plan because of schedule delays resulting from putting the project on hold for one year due to capital project investigation funding constraints;
- The Duncan Dam Replace Spillway Gates project was $2.2 million below plan because the project Implementation Phase was shifted from calendar year 2020 to calendar year 2022 to allow additional time to perform site investigations that verified the viability of gate life extension through refurbishment as the preferred alternative selection, rather than more costly gate replacements; and
- The Revelstoke Improve Left Bank Slope Stability project was $2.1 million below plan because of construction delays related to the COVID-19 pandemic.

The decrease in capital expenditures outlined above was partially offset by:

- The Revelstoke Replace Downie Slide Instrumentation project was $3.9 million above plan because of higher costs due to unforeseen complexities with accessing the remote site.

The remaining below plan variance of $4.1 million was due to smaller variances on various projects.

Fiscal 2021 capital additions were $10.3 million (or 23 per cent) below the fiscal 2021 Decision. This was primarily because:

- The Terzaghi - Spillway Chute Access Improvement project was $12.0 million below plan because project in-service date was delayed due to the time required to finalize the Conceptual Design to appropriately balance worker risk, overall cost, and long-term maintenance;
- The Revelstoke Improve Left Bank Slope Stability project was $11.5 million below plan because the project in-service date was delayed due to construction delays related to the COVID-19 pandemic;
- The Various Sites - Reservoir Booms Replacement was $5.9 million below plan because the project was initiated later than originally contemplated due to extended planning and scheduling; and
- The MCA - Rehabilitate Vertical Movement Gauges project was $2.9 million below plan because the project in-service date was delayed due to additional time required to complete the final instrumentation connection and calibration.

The decrease in capital additions outlined above was partially offset by:

- The W.A.C. Bennett Dam Spillway Gate Upgrade project was $22.9 million above plan because the project in-service date was delayed from fiscal 2020 to fiscal 2021 due to contractor related delays in finalizing a contract and executing work.

The remaining below plan variance of $0.9 million was due to smaller variances on various projects.

When considering the non-financial impacts of these lower than planned capital expenditures and capital additions arising from schedule delays, particularly with respect to the risk position of BC Hydro's dam fleet, please refer to BC Hydro's response to BCUC Information Request 1.53.4 of the Fiscal 2022 Revenue Requirements Application. In that response, BC Hydro explained that the dynamic and complex "brown field" nature of these projects and the need to balance several competing priorities can sometimes lead to schedule delays. BC Hydro further explained that interim controls – either operational or physical – are put into place to manage any deficiency to a tolerable state until the deficiency can be addressed through the project, so that schedule delays within dam safety projects do not typically have a significant impact on the risk position of BC Hydro's dam fleet.

Sustaining – Other

Fiscal 2021 capital expenditures were $139.0 million (or 38 per cent) below the fiscal 2021 Decision. This was primarily because:

- The Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior) project was $22.6 million below plan because the fiscal 2021 work program was delayed due to the restaged exterior coating scope of work;
- The Wahleach Recoat Penstock (Interior and Exterior) project was $15.5 million below plan because of a lack of Generator outage availability;
- The G.M. Shrum Upgrade HVAC System project was $15.4 million below plan because of a schedule delay due to rescoping and re-planning of the project;
- The Bridge River 2 - Strip and Recoat Penstock 2 Interior project was $8.6 million below plan because the project work was delayed due to the COVID-19 pandemic;
- The Bridge River 1 Replace Units 1-4 Generators / Governors project was $8.6 million below plan because of a schedule delay due to a procurement

strategy change and due to Directive 29 of the BCUC's Decision on BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (BCUC Order G-246-20) which directed BC Hydro to file a joint application for the Bridge River 1 Replace Units 1-4 Generators / Governors project and the Bridge River Transmission project;

- The Mica Upgrade HVAC System project was $8.5 million below plan because the project schedule and associated cashflow were revised due to design elaboration and constructability reviews during the Definition Phase;
- The Kootenay Canal Modernize Controls project was $7.2 million below plan because of longer than expected Conceptual and Feasibility Design Phases due to resource constraints, design complexities and scope confirmation;
- The Bridge River 2 Upgrade Units 5 and 6 project was $6.3 million below plan due to cost savings during construction;
- The Revelstoke Replace Fire Alarm System project was $4.7 million below plan because the construction start date changed due to an updated construction schedule from the contractor;
- The Jordan - Upgrade Governor & PRV Controls project was $4.7 million below plan because the unit outage required for construction was deferred due to design elaboration and coordination with the Jordan River - Switchyard Upgrade project to minimize outages at Jordan River substation;
- The Seton - Upgrade Unit project was $4.4 million below plan because the project was placed on hold to evaluate alternatives for a hydraulic bypass system;
- The Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior project was $4.4 million below plan because the project construction start date was delayed in order to align outages with the Bridge River 1 Replace Units 1-4 Generators /

Governors project. The scope for the two projects is separate but this approach provides efficiency and improves system water management;

- The Cheakamus Units 1 and 2 Generator Replacement project was $4.1 million below plan because the project was three months ahead of schedule and therefore part of the spend was in the prior fiscal period;
- The Mica - Intake Gantry Crane Refurbishment project was $3.8 million below plan because the project construction start date was deferred due to worker camp capacity restrictions related to the COVID-19 pandemic;
- The G.M. Shrum G1 to 10 Control System Upgrade project was $3.6 million below plan because of a schedule delay due to the COVID-19 pandemic and the Site C river diversion which deferred planned outage work;
- The Ladore - Redevelop Unit 1 project was $3.3 million below plan because the project was cancelled due to re-evaluation of the project need and timing; and
- The Mica Upgrade 600V Circuit Breakers project was $2.9 million below plan because additional time was required to complete the detailed design.

The decrease in capital expenditures outlined above was partially offset by:

- The MCA - Replace Reactors 5RX3 and 5RX4 project was $16.0 million above plan because this was an unplanned emergency replacement of failed equipment.

The remaining below plan variance of $26.4 million was due to smaller variances on many offsetting projects.

Fiscal 2021 capital additions were $257.8 million (or 82 per cent) below the fiscal 2021 Decision. This was primarily because:

- The Bridge River 2 Upgrade Units 7 and 8 project was $54.7 million below plan because the project in-service date was delayed due to an equipment fault resulting in the delay of Unit 7 commissioning;
- The Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior) project was $31.5 million below plan because the project in-service date was delayed due to the restaged exterior coating scope of work;
- The Wahleach Recoat Penstock (Interior and Exterior) project was $26.0 million below plan because the project in-service date was delayed due to the lack of Generator outage availability;
- The Bridge River 2 - Strip and Recoat Penstock 2 Interior project was $16.6 million below plan because the project in-service date was delayed due to crew size restrictions from the COVID-19 pandemic;
- The G.M. Shrum G1 to 10 Control System Upgrade project was $15.4 million below plan because the project in-service date was delayed due to the COVID-19 pandemic and Site C river diversion which deferred planned outage work;
- The Mica Upgrade HVAC System project was $12.6 million below plan because the project in-service date was delayed due to an updated project schedule resulting from design elaboration and progression of project planning activities;
- The Mica Upgrade 600V Circuit Breakers project was $12.0 million below plan because the project in-service date was delayed due to design delays and longer manufacturing lead times than planned;
- The Hugh Keenleyside Replace Service Water Piping project was $8.8 million below plan because the project in-service date was delayed due to reprioritization of capital projects and maintenance work at Hugh Keenleyside in response to COVID-19 impacts;

- The Seven Mile Replace Unit 1-4 Exciter Transformers project was $8.6 million below plan because the project schedule was updated as a result of the design scope elaboration, project planning and early contract engagement in the Definition Phase. The forecast in-service date is updated to fiscal 2022;
- The Cheakamus Replace Units 1 and 2 Turbine Inlet Valves project was $7.3 million below plan because of a schedule delay due to defects in the turbine inlet valves cast bodies that required recasting;
- The Bridge River 2 Upgrade Units 5 and 6 project was $6.5 million below plan because of cost savings during construction and delayed reconciliation of final contractor costs;
- Various - Water License Renewal was $5.3 million below plan because the project in-service date was delayed due to the Comptroller of Water Rights requesting more time to decide on the Water Licence Renewals;
- The Waneta – Sustaining project costs were $5.2 million below plan because the project in-service dates were delayed mainly due to the Unit 3 Life Extension work Definition Phase taking longer than anticipated causing the Implementation Phase to be delayed;
- The G.M. Shrum Draft Tube Maintenance Gates Refurbishment project was $4.5 million below plan because the project in-service date was delayed due to work being delayed by the COVID-19 pandemic;
- The Peace Canyon Draft Tube Maintenance Gates Refurbishment project was $4.4 million below plan because the project in-service date was delayed due to work being delayed by the COVID-19 pandemic;
- The Mica - Recoat Intake Maintenance Gates & Draft Tube Maintenance Gates project was $4.3 million below plan because the project in-service date was delayed due to work being delayed by the COVID-19 pandemic;

- The Alouette Upgrade Station Service project was $4.3 million below plan because the project in-service date was delayed due to an additional switching study and grounding test;
- The Cheakamus Units 1 and 2 Generator Replacement project was $4.2 million below plan because of lower trailing costs due to fewer risks materializing;
- The Mica Upgrade Town Site Building Roofs project was $4.1 million below plan because the project in-service date was delayed due to a work assessment review deferring construction work and worker camp capacity restrictions related to the COVID-19 pandemic; and
- The Peace Canyon Electrical Protection Upgrade project was $4.0 million below plan because the project was delayed by two years in order to move the required outage at Peace Canyon outside of the Site C diversion period.

The remaining below plan variance of $17.5 million was due to smaller variances on many offsetting projects.

Non-Integrated Areas and Diesel and Thermal Generation

Fiscal 2021 capital expenditures and additions for Non-Integrated Areas and Diesel and Thermal Generation were comparable to the fiscal 2021 Decision.

Portfolio Risk Adjustment

The Portfolio Risk Adjustment is meant to account for the uncertainty in the schedule and cost of projects. The Portfolio Risk Adjustment amount is calculated using a Monte Carlo simulation. A probability distribution is determined, based on historical Project Delivery performance information. The calculated Portfolio Risk Adjustment amount represents the difference (by fiscal year) between the expected value of the simulated portfolio forecast and the sum of individual project forecasts in the baseline Capital Plan.

The Fiscal 2021 Decision Portfolio Risk Adjustment amount was $(65.2) million for capital expenditures and $(74.6) million for capital additions.

10.3 Transmission Capital Expenditures and Additions Variance Explanations

Transmission fiscal 2021 capital expenditures and capital additions are provided in Table 16 and Table 17, below.

Table 16 Fiscal 2021 Transmission Capital Expenditures Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Transmission Growth				
Regional System Reinforcement	91.1	38.0	(53.1)	-58%
Bulk System Reinforcement	43.3	(3.5)	(46.8)	-108%
Station Expansion & Modification	22.5	30.6	8.1	36%
Feeder Positions / Section Additions	2.1	0.5	(1.6)	-77%
Generator Interconnections	3.6	4.7	1.1	32%
Transmission Load Interconnection	46.3	51.6	5.3	12%
Total Growth	208.9	121.9	(87.0)	-42%
Transmission Sustain - Stations				
Circuit Breakers	28.2	21.0	(7.2)	-26%
Other Power Equipment	104.6	99.9	(4.7)	-5%
Protection and Control	16.3	11.7	(4.6)	-28%
Stations Auxiliary Equipment	29.8	15.8	(14.0)	-47%
Stations Risk Mitigation	10.0	6.7	(3.3)	-33%
Telecommunications	25.1	18.2	(6.9)	-28%
Total Sustain - Stations	214.0	173.2	(40.8)	-19%
Transmission Sustain - Lines				
Cable Sustainment	8.9	(2.7)	(11.6)	-131%
O/H Lines Life Extension	70.1	62.4	(7.7)	-11%
O/H Lines Performance Improvement	1.4	3.9	2.5	179%
O/H Lines Risk Mitigation	3.6	6.4	2.8	77%
ROW Sustainment	9.8	9.9	0.1	1%
Third Party Requested Transmission Line Relocations	7.8	1.3	(6.5)	-83%
Total Sustain - Lines	101.6	81.1	(20.5)	-20%
Less: Portfolio Risk Adjustment	(39.0)	-	39.0	-100%
Total Gross	**485.5**	**376.3**	**(109.2)**	**-22%**
Less: Contribution in Aid	(14.8)	(9.0)	5.8	-39%
Total	**470.7**	**367.3**	**(103.4)**	**-22%**

Table 17 Fiscal 2021 Transmission Capital Additions Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Transmission Growth				
Regional System Reinforcement	58.2	97.4	39.2	67%
Bulk System Reinforcement	-	0.1	0.1	100%
Station Expansion & Modification	0.5	0.8	0.3	56%
Feeder Positions / Section Additions	0.2	-	(0.2)	-100%
Generator Interconnections	10.3	15.9	5.6	54%
Transmission Load Interconnection	16.1	41.6	25.5	158%
Total Growth	85.3	155.8	70.5	83%
Transmission Sustain - Stations				
Circuit Breakers	11.3	19.0	7.7	68%
Other Power Equipment	50.4	24.1	(26.3)	-52%
Protection and Control	13.1	2.8	(10.3)	-79%
Stations Auxiliary Equipment	26.8	6.9	(19.9)	-74%
Stations Risk Mitigation	20.0	6.4	(13.6)	-68%
Telecommunications	37.4	8.6	(28.8)	-77%
Total Sustain - Stations	159.0	67.8	(91.2)	-57%
Transmission Sustain - Lines				
Cable Sustainment	2.3	(3.4)	(5.7)	-249%
O/H Lines Life Extension	41.8	49.3	7.5	18%
O/H Lines Performance Improvement	1.4	1.7	0.3	22%
O/H Lines Risk Mitigation	10.2	6.1	(4.1)	-40%
ROW Sustainment	9.8	10.8	1.0	11%
Third Party Requested Transmission Line Relocations	9.8	0.5	(9.3)	-95%
Total Sustain - Lines	75.3	65.0	(10.3)	-14%
Less: Portfolio Risk Adjustment	(90.0)	-	90.0	-100%
Total Gross	**229.6**	**288.6**	**59.0**	**26%**
Less: Contribution in Aid	(29.2)	(8.6)	20.6	-71%
Total	**200.4**	**280.0**	**79.6**	**40%**

Transmission Growth - Regional System Reinforcement

Fiscal 2021 capital expenditures were $53.1 million (or 58 per cent) below the fiscal 2021 Decision primarily because:

- The Peace Region Electric Supply (**PRES**) project was $27.9 million below plan primarily because BC Hydro received contributions of $25 million from the Government of Canada which were not accounted for in the fiscal 2021 RRA plan. Project costs were also lower than planned;

- The East Vancouver - Substation Construction project was $9.1 million below plan because the project has been delayed for three years, following the purchase of property for the development of a West End Substation. This purchase allowed BC Hydro to proceed with the preferred project staging (i.e., constructing the West End Substation first, while delaying the construction of the East Vancouver Substation);
- The West Kelowna Transmission and Westbank Upgrade projects were $8.9 million below plan because the Transmission project returned to the Conceptual Design Stage to re-evaluate the existing alternatives and consider new alternatives in response to a higher than anticipated revised cost estimate for the Leading Alternative; and
- The Bridge River Transmission project was $8.5 million below plan because conceptual design was delayed in order to allow additional time to complete the business case and develop a regulatory application in accordance with Directive 29 of the BCUC's Decision on the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.

The decrease in capital expenditures outlined above was partially offset by above plan smaller variances of $1.3 million from various projects.

Fiscal 2021 capital additions were $39.2 million (or 67 per cent) above the fiscal 2021 Decision primarily because:

- The PRES project was $43.1 million above plan because the substation assets were placed in service ahead of Plan in fiscal 2021 due to their construction being completed ahead of schedule.

The increase in capital additions outlined above was partially offset by:

- The George Tripp Station Modification project was $2.7 million below plan because the project in-service date was delayed due to longer design duration as a result of resource constraints, and longer construction duration as a result of system constraints impacting the availability of required line outages; and

- $1.2 million smaller below plan variances on various projects.

Transmission Growth – Bulk System Reinforcement

Fiscal 2021 capital expenditures were $46.8 million (or 108 per cent) below the fiscal 2021 Decision primarily because:

- The Peace to Kelly Lake Capacitors project was $41.1 million below plan because the project was cancelled. Based on updated load forecast information, BC Hydro determined that the need for an increase in the transfer capability along the Peace Region to Kelly Lake transmission corridor to deliver power to the load centers in the south of the province could be delayed until after fiscal 2031. The sustainment portion of the project was grouped into a new project – the Peace to Kelly Lake Sustainment Project.

The remaining below plan variance of $5.7 million was due to smaller variances on various projects.

Fiscal 2021 capital additions were comparable to the fiscal 2021 Decision.

Transmission Growth – Transmission Load Interconnection

Fiscal 2021 capital expenditures were comparable to the fiscal 2021 Decision.

Fiscal 2021 capital additions were $25.5 million (or 158 per cent) above the fiscal 2021 Decision primarily because:

- The UBC Load Increase Stage 2 project was $36.7 million above plan because the project was put into service in fiscal 2021, ahead of the planned fiscal 2022 in-service date as project schedule risks did not materialize and therefore the project schedule contingency was not used.

The increase in capital additions outlined above was partially offset by:

- $11.2 million below plan variances that resulted from various third-party driven customer projects due to the timing of projects being planned and put in-service.

All other line items under Transmission Growth in fiscal 2021 for both capital expenditures and capital additions were comparable to the fiscal 2021 Decision.

Transmission Sustain-Stations

Circuit Breakers

Fiscal 2021 capital expenditures and capital additions were comparable to the fiscal 2021 Decision.

Other Power Equipment

Fiscal 2021 capital expenditures were comparable to the fiscal 2021 Decision.

Fiscal 2021 capital additions were $26.3 million (or 52 per cent) below the fiscal 2021 Decision. This was primarily due to the following:

- The BR1 T3 & BRT T4A Replacement project was $18.8 million below plan because the T4 portion of the project schedule was delayed during the Identification Phase to allow additional time to complete the alternative analysis and selection. The T3 portion of the project was prioritized and moved to a separate project due to the unplanned failure of BR1 T3; and
- The Peace Region to Kelly Lake - Reactor Replacement (Phase 1) project was $9.3 million below plan because the second reactor installation schedule was delayed due to the COVID-19 pandemic.

The decrease in capital additions above was partially offset by $1.8 million of smaller above plan variances on various projects.

Protection and Control

Fiscal 2021 capital expenditures were comparable to the fiscal 2021 Decision.

Fiscal 2021 capital additions were $10.3 million (or 79 per cent) below the fiscal 2021 Decision. This was primarily because:

- The SCADA RTU Replacement - Stage 9 project was $3.5 million below plan because the project in-service date was delayed due to project design deliverables completion delays as a result of resources being shifted to the other higher priority work such as Mandatory Reliability Standards (**MRS**) compliance related projects; and
- The SCADA RTU Replacement - Stage 10 project was $3.3 million below plan because the project in-service date was delayed due to project design deliverable completion delays as a result of resources being shifted to the other higher priority work such as MRS compliance related projects.

The remaining below plan variance of $3.5 million was due to smaller variances on various projects.

Stations Auxiliary Equipment

Fiscal 2021 capital expenditures were $14.0 million (or 47 per cent) below the fiscal 2021 Decision primarily due to the following:

- The Joseph Creek (**JOE**) Substation Upgrade project was $5.7 million below plan because project was put on-hold pending the review and finalization of the Wood Pole Substations Strategy during the Identification Phase;
- The Lumby No. 2 - Substation Wood Pole Replacement project was $3.2 million below plan because the project was delayed pending the review and finalization of the Wood Pole Substations Strategy and due to resource constraints; and

- The Station Wood Pole Replacement Program - Chase (**CHS**) Substation project was $1.9 million below plan because the project start was delayed pending the review and finalization of the Wood Pole Substation Strategy.

The remaining variance of $3.2 million was due to smaller below plan variances on various projects.

Fiscal 2021 capital additions were $19.9 million (or 74 per cent) below the fiscal 2021 Decision primarily because:

- The Wood Pole Substation Replacement – Britannia Substation (**BTA**) project was $5.9 million below plan because the construction schedule was delayed due to a prolonged procurement process. A further delay occurred while the project waited for an approved customer outage for the project to resolve final construction deficiencies;
- The Wood Pole Substation Replacement Program - Chase Substation (**CHS**) project was $3.1 million below plan because the project start was delayed pending the review and finalization of the Wood Pole Substation Strategy;
- The Wood Pole Substation Replacement Program - Clinton Substation (**CLN**) project was $2.4 million below plan because the project in-service date was delayed pending the review and finalization of the Wood Pole Substation Strategy;
- The Como Lake (**COK**) Substation Cable Replacement was $1.7 million below plan because the project in-service date was delayed due to resource constraints and station outage constraints. The procurement of power cables was also delayed due to the COVID-19 pandemic; and
- The Fire Risk Program for Stations was $1.3 million below plan because the project in-service date was delayed due to change of scope and work methodology and due to the COVID-19 pandemic.

The remaining variance of $5.5 million was due to smaller below plan variances on various projects.

Station Risk Mitigation

Fiscal 2021 capital expenditures were comparable to the fiscal 2021 Decision.

Fiscal 2021 capital additions were $13.6 million (or 68 per cent) below the fiscal 2021 Decision. This was primarily because:

- The Oil Spill Containment - F17/F18 (ALZ / MDN) project for the Atchelitz and Meridian Substations was $7.2 million below plan because the project in-service date was delayed due to the COVID-19 pandemic.

The remaining variance of $6.4 million was due to smaller below plan variances on various projects.

Telecommunication

Fiscal 2021 capital expenditures were comparable to the fiscal 2021 Decision.

Fiscal 2021 capital additions were $28.8 million (or 77 per cent) below the fiscal 2021 Decision. This was primarily due to the following:

- The Vancouver Island Radio System project was $21.5 million below plan because the project in-service date was delayed due to issues related to the supply and performance of the telecom equipment. Additional time and effort were required for procurement, testing, standardization of new equipment, and development of new system architecture; and
- The CPM MW Repeater Building Replacement project was $5.1 million below plan because the project in-service date was delayed due to the COVID-19 pandemic and due to Communication, Protection and Control resource constraints.

The decrease in capital additions above was partially offset by:

- The Copper Mountain ice mitigation project was $6.6 million above plan because the in-service date was delayed from fiscal 2020 to fiscal 2021 due to a deficiency that was required to be rectified prior to the project being put in service.

The remaining below plan variance of $8.8 million was due to smaller variances on various projects.

Transmission Sustain-Lines

Cable Sustainment

Fiscal 2021 capital expenditures were $11.6 million (or 131 per cent) below the fiscal 2021 Decision. This was primarily because:

- The Gulf Islands - Transmission Reinforcement was $5.3 million below plan because the project initiation was delayed to allow more time to complete planning activities including the identification and evaluation of additional alternatives; and
- The Asset Retirement Obligation (**ARO**) provision adjustment of ($3.4) million on the 230 kV and 138 kV Submarine Cables was re-evaluated at the fiscal 2021 year-end which resulted in an adjustment reducing the liability by $3.4 million.

The remaining below plan variance of $2.9 million was due to variances on many smaller projects.

Fiscal 2021 capital additions were comparable to the fiscal 2021 Decision.

All other line items under Transmission Sustain-Lines in fiscal 2021 for both capital expenditures and capital additions were comparable to the fiscal 2021 Decision.

Portfolio Risk Adjustment

The Portfolio Risk Adjustment is meant to account for the uncertainty in the schedule and cost of projects. The Portfolio Risk Adjustment amount is calculated using a Monte Carlo simulation. A probability distribution is determined, based on historical Project Delivery performance information. The calculated Portfolio Risk Adjustment amount represents the difference (by fiscal year) between the expected value of the simulated portfolio forecast and the sum of individual project forecasts in the baseline Capital Plan.

The Fiscal 2021 Decision Portfolio Risk Adjustment amount was $(39.0) million in capital expenditures and $(90.0) million in capital additions.

Contribution in Aid

Fiscal 2021 Transmission Contribution in Aid expenditures were comparable to the fiscal 2021 Decision.

Fiscal 2021 Transmission Contribution in Aid additions were $20.6 million (or 71 per cent) below the fiscal 2021 Decision due to timing differences on the completion of customer work and a lower volume of third-party requests for relocations than originally planned.

10.4 Distribution Capital Expenditures and Additions Variance Explanations

Distribution fiscal 2021 actual to Fiscal 2021 Decision capital expenditures and capital additions are provided in Table 18 and Table 19, below.

The distribution system improvement portfolio is primarily comprised of small projects, with the average project size in the $1 million to $2 million range with short duration.

The System Expansion and Improvement portfolio is subject to rapidly changing priorities and the planning processes must be dynamic to respond to the emerging needs on the distribution system. This may result in variances in the timing and selection of projects in the portfolio in a given year.

Table 18 Fiscal 2021 Distribution Capital Expenditures Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Distribution Growth				
Customer Driven	234.0	315.8	81.8	35%
System Expansion and Improvement	50.0	74.7	24.7	49%
Uneconomic Extension Assistance	0.6	-	(0.6)	-100%
Total Growth	284.6	390.5	105.9	37%
Distributon Sustain				
System Expansion and Improvement	57.2	46.3	(10.9)	-19%
Asset Replacement				
Poles	63.3	48.7	(14.6)	-23%
Overhead Equipment	15.6	30.1	14.5	93%
Underground Equipment	19.4	51.0	31.6	163%
Trouble	18.0	20.5	2.5	14%
Asset Replacement sub-total	116.3	150.3	34.0	29%
Beautification	1.1	4.5	3.4	309%
Electric Vehicle Charging Infrastructure	2.2	2.9	0.7	33%
Total Sustain	176.8	204.1	27.3	15%
Total Gross	**461.4**	**594.6**	**133.2**	**29%**
Less: Contribution in Aid	(133.7)	(186.7)	(53.0)	40%
Total	**327.7**	**407.9**	**80.2**	**24%**

Table 19 Fiscal 2021 Distribution Capital Additions Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Distribution Growth				
Customer Driven	239.3	273.1	33.8	14%
System Expansion and Improvement	104.3	72.9	(31.4)	-30%
Uneconomic Extension Assistance	0.6	0.2	(0.4)	-72%
Total Growth	344.2	346.2	2.0	1%
Distributon Sustain				
System Expansion and Improvement	74.1	52.3	(21.8)	-29%
Asset Replacement				
Poles	64.9	45.9	(19.0)	-29%
Overhead Equipment	15.4	22.1	6.7	44%
Underground Equipment	20.8	44.4	23.6	114%
Trouble	18.0	20.4	2.4	13%
Asset Replacement sub-total	119.1	132.9	13.8	12%
Beautification	1.1	5.1	4.0	365%
Electric Vehicle Charging Infrastructure	2.2	(0.5)	(2.7)	-121%
Total Sustain	196.5	189.8	(6.7)	-3%
Total Gross	**540.7**	**536.0**	**(4.7)**	**-1%**
Less: Contribution in Aid	(136.6)	(172.1)	(35.5)	26%
Total	**404.1**	**363.9**	**(40.2)**	**-10%**

Distribution Growth – Customer Driven

Fiscal 2021 capital expenditures were $81.8 million (or 35 per cent) above the fiscal 2021 Decision due to an increase in distribution customer driven extension activities, meter purchases for secondary connections, the Ministry of Transportation and Infrastructure relocation activities and the required design effort to support these increases. This work is difficult to plan as it is dependent on customer requests and their related timing. The increase in capital expenditures was partially offset by the increase in contributions received, as explained in the Contribution in Aid section below.

Fiscal 2021 capital additions were $33.8 million (or 14 per cent) above the fiscal 2021 Decision primarily due to the increase in capital expenditures as well as the timing of a few major customer projects going in-service in fiscal 2021.

Distribution Growth - System Expansion and Improvement

Growth-driven system expansion and improvement expenditures address existing capacity constraints to meet anticipated customer load growth. The priority of growth-driven system upgrades is influenced by new customer load connections and general load growth from existing customers. This category of expenditures is subject to year over year fluctuations from plan as a result of changes in scope, cost and schedule for projects as well as variances between forecast and actual customer load growth.

Fiscal 2021 capital expenditures were $24.7 million (or 49 per cent) above the fiscal 2021 Decision primarily because:

- The Bringing additional capacity from ARN to Tilbury project was $6.7 million above plan because of increased construction costs and duration mainly due to adverse as-found ground condition areas which resulted in unplanned spend in fiscal 2021;
- The LM-COQ-694 COK Distribution Egress Reinforcement project was $6.5 million above plan because additional time was required to complete the work and there were additional costs for water treatment plants and dewatering;
- The LM-FVW-701 - New KI2 duct bank egress & Feeder project was $5.8 million above plan due to civil cost escalations, extra cable costs, nighttime work due to a request from the Ministry of Transportation and Infrastructure and dewatering costs;
- The New MUR Circuit to Offload MUR 12F66 and MUR 12F84 project was $5.2 million above plan due to additional scope and a delay in the in-service date;

- The System Improvement Minor Capital Program was $4.4 million above plan due to higher volumes of work driven by new customer connections and general load growth from existing customers;
- The FV-CHK-018 New ALZ 25F82 to offload WAH 25F51 project was $2.7 million above plan because the project was expected to be completed in fiscal 2020. The project was delayed to fiscal 2021 due to additional reconductoring and underground work added to the project scope; and
- The HPN 12F54, 72Q, 73Q, and 324 Voltage Conversion project was $2.7 million above plan because work was delayed to fiscal 2021 by the high volume of customer vault negotiations required and slower than expected permitting for underground work;

The increase in capital expenditures above was partially offset by:

- The Three new MLE Feeders to offload CBN project was $7.3 million below plan because the project completion date was delayed due to the timing of MLE feeder positions being available in the substation which is currently being upgraded in a separate project;
- The Two Fleetwood feeders to offload McLellan project was $6.9 million below plan because the project completion date was delayed due to scope changes;

The remaining above plan variance of $4.9 million was due to smaller variances on various projects.

Fiscal 2021 capital additions were $31.4 million (or 30 per cent) below the fiscal 2021 Decision primarily due to the following:

- The Two Fleetwood feeders to offload McLellan project was $13.2 million below plan because the project completion date was delayed due to scope changes;

- The HPN 77Q, 323, 326 and 327 Voltage Conversion Preparation project was $10.0 million below plan because the project completion date was delayed due to a high volume of customer vault negotiations;
- The Three new MLE Feeders to offload CBN project was $8.7 million below plan because the project completion date was delayed due to the timing of MLE feeder positions being available in the substation which is currently being upgraded in a separate project;
- The 12F51 & 53 HPN Voltage Conversion project was $8.0 million below plan because the project completion date was delayed due to customer equipment procurement delays;
- The New MUR Circuit to Offload MUR 12F66 and MUR 12F84 project was $7.3 million below plan because the project completion date was delayed due to additional scope for a duct bank;
- The Voltage Conversion Prep for RIM Substation project was $7.3 million below plan because the project completion date was delayed due to removal of scope from the project;
- The Lower Mainland - George Dickie Feeder Voltage Conversion project was $5.0 million below plan because the project completion date was delayed to accommodate the customers' conversion schedules. There were also fewer poles replaced than planned; and
- The LM-VAN-076 West End Voltage Conversion project was $3.4 million below plan because the project completion date was delayed due to delays in customer vault negotiations.

The decrease in capital additions above was partially offset by:

- The Bringing additional capacity from ARN to Tilbury project was $28.5 million above plan because the project in-service date was delayed from fiscal 2020 to fiscal 2021 due to increased construction duration mainly due to as-found ground conditions in the area; and

- Above plan variances of $3.0 million from various smaller projects.

Uneconomic Extension Assistance

Fiscal 2021 capital expenditures and capital additions were comparable to the Fiscal 2021 Decision.

Distribution Sustain - System Expansion and Improvement

System expansion and improvement sustaining expenditures maintain and improve distribution system performance including addressing customer reliability, safety risks and meeting regulatory, legal or environmental requirements.

Fiscal 2021 capital expenditures were $10.9 million (or 19 per cent) below the Fiscal 2021 Decision primarily because:

- The Downtown Vancouver - Underground Murrin Feeders to Eliminate H-Frames in Gastown was $10.6 million below plan because of delays in the City of Vancouver’s approval of designs.

The remaining below plan variance of $0.3 million was due to smaller variances on various projects.

Fiscal 2021 capital additions were $21.8 million (or 29 per cent) below the Fiscal 2021 Decision primarily due to the following:

- The Downtown Vancouver - Underground Murrin Feeders to Eliminate H-Frames in Gastown was $11.6 million below plan because the in-service date was delayed to fiscal 2022 mainly due to delay related to the City of Vancouver’s approval of designs;

- The New DGR Circuit for Customer Vaults at Pacific and Howe project was $5.5 million below plan because the project in-service date was delayed due to the COVID-19 pandemic and City of Vancouver traffic permit restrictions;
- The New DGR Circuit for Customer Vaults at Drake and Howe project was $8.8 million below plan because the project in-service date was delayed as the construction schedule for the project was sequenced to be after the New DGR Circuit for Customer Vaults at Pacific and Howe project, which was delayed, as explained above;
- The Merritt - New Merritt 25F114 Douglas Lake Ranch project was $2.3 million below plan because of a delay in the resolution of property access issues; and
- The Primary Metering Kit Replacement project was $2.2 million below plan because the project in-service date was delayed as a result of procurement delays for PCB metering kits.

The decrease in capital additions above was partially offset by:

- The H-Frame Elimination - Chinatown project was $8.4 million above plan because the project was placed in-service in fiscal 2021 instead of fiscal 2020, as originally forecasted; and
- Above plan variances of $0.2 million from various smaller projects.

Distribution Sustain - Asset Replacement

Distribution Asset replacements are planned and adjusted as an entire program based on inspections and changes in the prioritization of different assets.

Fiscal 2021 capital expenditures were $34 million (or 29 per cent) above the fiscal 2021 Decision primarily due to higher volumes of underground and overhead replacements; partially offset by lower volume of joint-use pole replacements and true-up of the third-party recoveries received.

Fiscal 2021 capital additions were $13.8 million (or 12 per cent) above the fiscal 2021 Decision primarily due to higher volumes of underground replacements and overhead replacements.

Contribution in Aid

Fiscal 2021 Distribution Contribution in Aid expenditures were $53.0 million (or 40 per cent) above the fiscal 2021 Decision primarily due to higher than planned distribution customer driven extension activities.

Fiscal 2021 Distribution Contribution in Aid additions were $35.5 million (or 26 per cent) above fiscal 2021 Decision primarily due to the increase in capital expenditures as explained above.

10.5 Business Support Capital Expenditures and Additions Variance Explanations

Business Support includes capital expenditures and additions for Technology, Properties, Fleet, and Other categories. Business Support Fiscal 2021 capital expenditures and capital additions are presented by category in the tables below.

Table 20 Fiscal 2021 Business Support Capital Expenditures Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Business Support				
Technology and other Technology (Tables 21 and 27)	56.0	90.8	34.8	62%
Properties	55.3	56.0	0.7	1%
Fleet	27.8	31.4	3.6	13%
Business Support - Other	47.2	23.4	(23.9)	3%
Total	**186.3**	**201.6**	**15.3**	**8%**

Table 21 Fiscal 2021 Business Support Capital Additions Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Business Support				
Technology and other Technology (Tables 22 and 28)	75.5	164.9	89.4	118%
Properties	55.6	70.9	15.3	27%
Fleet	27.8	26.8	(1.0)	-4%
Business Support - Other	43.5	22.7	(20.8)	-48%
Total	**202.4**	**285.3**	**82.9**	**41%**

Technology

Table 22 Fiscal 2021 Technology Capital Expenditures Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Technology	55.5	89.6	34.1	61%
Total	**55.5**	**89.6**	**34.1**	**61%**

Table 23 Fiscal 2021 Technology Capital Additions Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Technology	75.0	164.9	89.9	120%
Total	**75.0**	**164.9**	**89.9**	**120%**

Fiscal 2021 capital expenditures were $34.1 million (or 61 per cent) above the fiscal 2021 Decision. This was primarily due to the following:

- The Supply Chain Applications project was $7.9 million above plan because the project was planned for completion in fiscal 2020 with no planned fiscal 2021 expenditures. The schedule was extended to complete the build and testing activities, due to a combination of increased project complexity and the COVID-19 pandemic. The COVID-19 pandemic also resulted in additional cost to rework and deliver the training remotely;

- The Information Technology Service Management Toolset project was $4.3 million above plan because the project was planned for completion in fiscal 2020 with no planned fiscal 2021 expenditures. The impact to schedule and costs was due to additional project design considerations and complexity, as well as a change to the accounting treatment for license purchases;
- The Windows 10 PC OS Upgrade project was $4.2 million above plan because the project was planned for completion in fiscal 2020 with no planned fiscal 2021 expenditures. The impact to schedule and cost was primarily due to additional deployment activities and security controls;
- The Microsoft Exchange 2010 to 2016 Upgrade project was $4.1 million above plan because the project was planned for completion in fiscal 2020 with no planned fiscal 2021 expenditures. The impact to schedule and cost was due to BC Hydro’s decision to leverage Microsoft’s cloud solution for its email application following a change to *BC’s Freedom of Information and Protection of Privacy Act*;
- The Energy Management System 3.3 Upgrade project was $3.0 million above plan because the project was not in the fiscal 2021 Decision. BC Hydro reprioritized this project to begin in the test period, in order to maintain operational stability and continue to maintain compliance with MRS requirements;
- The Customer Connect Web-Enablement Project was $2.4 million above plan because the project was planned for completion in fiscal 2020 with no planned fiscal 2021 expenditures. The schedule was extended due to project complexity and resource availability issues;
- The PowerOn 4.3 Upgrade project was $2.3 million above plan because the project was not in the fiscal 2021 Decision. BC Hydro reprioritized this project to

begin in the test period, in order to maintain operational stability and vendor support.

The remaining above plan variance of $5.9 million was due to variances on many smaller projects.

Fiscal 2021 capital additions were $89.9 million (or 120 per cent) above the fiscal 2021 Decision. This was primarily because:

- The Supply Chain Applications project was $67.5 million above plan primarily due to the in-service date being delayed to fiscal 2021 as a result of a schedule extension for the build and testing activities as well as a delay in the project go-live training due to the COVID-19 pandemic.

The remaining above plan variance of $22.4 million was due to the portfolio adjustment of ($10.5) million in the Fiscal 2021 Plan, and variances of $11.9 million from various smaller projects.

Properties

Table 24 Fiscal 2021 Properties Capital Expenditures Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Building Development	39.7	14.4	(25.3)	-64%
Building Improvements and Others	15.6	41.6	26.0	167%
Total	**55.3**	**56.0**	**0.7**	1%

Table 25 Fiscal 2021 Properties Capital Additions Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Building Development	40.0	23.5	(16.5)	-41%
Building Improvements and Others	15.6	47.4	31.8	204%
Total	**55.6**	**70.9**	15.3	27%

BC Hydro's approach is to manage the Properties' Building Improvements projects and Building Development projects as a combined Building Projects portfolio to meet the annual plan. As some projects are delayed, others are advanced, based on changing priorities which may include asset condition or operational requirements.

Fiscal 2021 capital expenditures for Properties' Building Projects were comparable to the fiscal 2021 Decision.

Fiscal 2021 capital additions for Properties' Building Projects were $15.3 million (or 27 per cent) above the fiscal 2021 Decision. This is primarily because of the following:

- A reprioritization of Building Improvement projects within the portfolio resulted in $31.8 million of additions above Plan, reflecting the shorter time for these projects to come into service as compared to the larger Building Development projects;
- Long Beach Field Building Redevelopment project was $8.7 million above Plan due to the in-service date moving to fiscal 2021 due to delays in obtaining two building permits; and
- Materials Management Building Redevelopment project was $2.4 million above Plan because the as-found conditions on the renovation part of this project resulted in additional permitting and construction costs.

The increase in capital additions above was partially offset by:

- The Chilliwack Facility Building Redevelopment project was $28.2 million lower than Plan as it was delayed due to the challenges in acquiring suitable land for the new field office.

The remaining above plan variance of $0.6 million was due to smaller variances on various projects.

Fleet

Table 26 Fiscal 2021 Fleet Capital Expenditures Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Fleet	27.8	31.4	3.6	13%
Total	**27.8**	**31.4**	**3.6**	**13%**

Table 27 Fiscal 2021 Fleet Capital Additions Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Fleet	27.8	26.8	(1.0)	-4%
Total	**27.8**	**26.8**	**(1.0)**	**-4%**

Fiscal 2021 capital expenditures and capital additions for Fleet were comparable to the fiscal 2021 Decision.

Business Support - Other and Other Technology

Table 28 Fiscal 2021 Business Support –Other and Other Technology Capital Expenditures Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Business Support - Other	47.2	23.4	(23.9)	-51%
Other Technology	0.5	1.2	0.7	-60%
Total	**47.7**	**24.6**	**(23.2)**	**-49%**

Table 29 Fiscal 2021 Business Support –Other and Other Technology Capital Additions Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Business Support - Other	43.5	22.7	(20.8)	-48%
Other Technology	0.5	-	(0.5)	-100%
Total	**44.0**	**22.7**	**(21.3)**	**-48%**

Business Support - Other

Business Support – Other is comprised of capital expenditures such as security equipment, field tools and minor equipment.

Fiscal 2021 capital expenditures for Business Support - Other were $23.9 million (or 51 per cent) below the Fiscal 2021 Decision primarily because:

- The Squamish Area Reinforcement Property Acquisition project (Project B in Appendix I of the F2020-F2021 RRA) was $10.4 million below plan because the project was cancelled. The decision was based on an updated load forecast, and it was determined that the additional capacity in the area will not be required until approximately 2040;
- The Oil Management Department Tank Farm Upgrade was $6.2 million below plan because of the scale and complexity of the design work resulting in delays and a revised project schedule; and
- The Learning & Development – Energized Training Substation was $6.0 million below plan because the project was cancelled due to shifting priorities and uncertainty with regard to the site location.

The remaining below plan variance of $1.3 million was due to variances on various smaller projects.

Fiscal 2021 capital additions for Business Support - Other were $20.8 million (or 48 per cent) below the fiscal 2021 Decision primarily because:

- The Squamish Area Reinforcement Property Acquisition project (Project B in Appendix I of the F2020-F2021 RRA) was $10.4 million below plan because the project was cancelled, as explained above; and
- The Oil Management Department Tank Farm Upgrade was $8.5 million below plan because the project was delayed due to a revised project schedule.

The remaining below plan variance of $1.9 million was due to variances on various smaller projects.

Other Technology

Fiscal 2021 capital expenditures and capital additions were comparable to the fiscal 2021 Decision.

10.6 Site C Project Capital Expenditures and Additions Variance Explanations

Site C Project fiscal 2021 capital expenditures and capital additions are presented in the tables below.

Table 30 Fiscal 2021 Site C Project Capital Expenditures Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Total Site C	**1,535.5**	**1,725.0**	**189.5**	**12%**

Table 31 Fiscal 2021 Site C Project Capital Additions Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Total Site C	**189.4**	**220.9**	**31.5**	17%

Fiscal 2021 capital expenditures were $189.5 million (or 12 per cent) above the fiscal 2021 Decision. Variances were primarily due to:

- Unplanned COVID-19 monthly premiums related to contractor costs to comply with COVID-19 safety requirements;
- Acceleration of main civil work to meet river diversion milestone date;
- Higher than planned costs for highway re-alignment and quarry work; and

- Reservoir clearing expenditures originally planned for fiscal 2020 that were incurred in fiscal 2021.

These were partially offset by a slowdown of generating and spillway work to essential work due to the COVID-19 pandemic earlier in the fiscal year and the timing of property acquisitions.

Further detail on the reasons for these variances are provided in BC Hydro's Site C quarterly progress reports to the BCUC.

Fiscal 2021 capital additions were $31.5 million (or 17 per cent) above the fiscal 2021 Decision primarily due to:

- In-service of the outdoor portion of the Peace Canyon Gas-Insulated Switchgear (part of the Transmission-related assets) originally planned for fiscal 2020 that occurred in fiscal 2021; and
- Higher than planned costs for the first transmission line that was placed in-service in fiscal 2021.

11 Capital Projects and Programs: First Full Funding Amount vs Estimate at Completion

In compliance with BCUC Order No. G-313-19,[3] Table 32 below provides a comparison of the First Full Funding (**FFF**) amount and estimate at completion (**EAC**) for all projects and programs of projects that meet the following criteria:

- Achieved final in-service date between April 1, 2020 and March 31, 2021; or final in-service date achieved prior to this fiscal year and where the remaining capital expenditures have increased 25 per cent or more and a minimum

[3] BCUC Order G-313-19 from the Review of the Regulatory Oversight of Capital Expenditures and Projects proceedings, page 27, "The final, actual cost for completed capital projects and programs above a materiality threshold."

amount of $0.5 million compared to the estimated remaining capital expenditures when previously reported;[4] and

- Met a materiality threshold of total capital expenditures of at least $20 million for Power System and Building projects and programs, and $10 million for Technology projects and programs. These align with the thresholds for inclusion in Appendix J in future revenue requirements applications; and
- Were not recurring projects and programs that were financially authorized at a group, program or other aggregated level. This ensures consistency with the information provided in the Attachment to Section 7.

[4] The increase of 25 per cent and a minimum amount of $0.5 million compared to amounts previously reported criteria will be used going forward as this is the first time providing this report.

Table 32 includes the variance between the EAC[5] and the FFF[6] amount and provides a brief explanation for any variance greater than or equal to 10 per cent.

Table 32 Projects and Programs with Final In-Service Dates between April 1, 2020 to March 31, 2021

($ million)

A	B			C	D	E	F		G	H	I	J	K	
Planning ID	Name of Project	BCUC Application Reference -if applicable (Note 1)	F20-F21 RRA Appendix J Reference	Actual In-Service Date (Note 2)	Financially Closed (Note 3)	First Full Funding Amount (Note 4)	Appendix I Authorized Amount (Note 5)	BCUC Application Approved Amount (Note 1)	LTD Costs (Note 6)	Estimate At Completion (Note 7)	Variance [H-E]	Diff (%) [I/E]	Variance Explanation (>=10 percent)	BCUC Application Progress Reports Reference (Note 1)
94003	UBC Load Increase Stage 2	N/A	N/A	F2021	N	51.6	55.2	N/A	49.8	55.0	3.4	7%		N/A
92525	Fort St. John and Taylor Electric Supply	N/A	Page 67	F2021	N	46.6	53.1	N/A	50.9	52.0	5.4	12%	A	N/A
G000656	W.A.C. Bennett Dam Spillway Gate Upgrade	N/A	Page 5	F2021	N	42.5	47.5	N/A	31.1	35.1	(7.4)	-17%	B	N/A
900749	Bringing additional capacity from ARN to Tilbury (FV-FVW-057)	N/A	N/A	F2021	N	22.0	23.7	N/A	29.7	30.1	8.1	37%	C	N/A
T001127	Supply Chain Applications	N/A	Page 121	F2021	N	61.1	-	N/A	67.5	69.0	7.9	13%	D	N/A
YT-00708	ITSM Tool	N/A	N/A	F2021	N	1.7	-	N/A	17.4	17.4	15.7	924%	E	N/A

Note 1	BCUC Application refers to CPCN or Section 44.2 Applications
Note 2	Actual in-service date refers to the final project in-service date achieved
Note 3	Financally closed is when the project has completed all project closing procedures, no additional incremental costs are expected, and project has been closed in the financial system
Note 4	First Full Funding refers to the total capital cost of the project (excluding project reserve) when it was first approved for full Implementation Phase by BC Hydro
Note 5	Authorized Amount refers to the total capital cost of the project, including project reserve, included in the F20-21 RRA Appendix I
Note 6	LTD costs refer to the life-to-date capital costs as of March 31, 2021
Note 7	Estimate at Completion refers to the forecasted capital cost when the project is expected to be financially closed

Note A: The Fort St. John and Taylor Electric Supply project was $5.4 million (or 12 per cent) above plan because the substation civil construction costs and general site costs were higher than the estimate.

Note B: The W.A.C. Bennett Dam Spillway Gate Upgrade project was $7.4 million (or 17 per cent) below plan because the project team worked with the Design-Build contractor to re-plan and optimize construction work which reduced on-site duration and costs.

5 The estimate at completion (**EAC**) is the forecast of capital expenditures for the project or program at financial close. It includes the actual capital cost of the project or program at the in-service date plus any estimated trailing costs to address deficiencies or to otherwise complete the project or program and achieve financial close.

6 The First Full Funding (**FFF**) amount includes actual capital expenditures incurred during the Identification and Definition Phases plus the estimate of capital expenditures for the Implementation Phase approved before the Implementation Phase. Approval of First Full Funding is required to start the Implementation Phase.

Note C: The Bringing additional capacity from ARN to Tilbury project was $8.1 million (or 37 per cent) above plan because the work methodology was changed for a portion of the civil construction which led to higher cost than the estimate.

Note D: The Supply Chain Applications project was $7.9 million (or 13 per cent) above plan because there were project schedule extensions and additional costs associated with the build and testing activities due to a combination of increased project complexity and the COVID-19 pandemic. The COVID-19 pandemic also resulted in additional cost to re-work and deliver the training remotely.

Note E: The Information Technology Service Management Toolset (**ITSM**) project was $15.7 million (or 924 per cent) above plan because the prepaid and future software subscription license costs, which were originally expected to be operating costs, were determined to be eligible for capitalization. There were also cost increases due to project complexity and additional design considerations.

BC Hydro Fiscal 2023 to Fiscal 2025

Revenue Requirements Application

Appendix Y

Expert Report on Benchmarking Terms of Reference

BEFORE THE
BRITISH COLUMBIA UTILITIES COMMISSION

British Columbia Hydro & Power Authority ("BC Hydro") Application to the British Columbia Utilities Commission ("Commission") for Approval of Revenue Requirements and Rates for Fiscal 2023-Fiscal 2025

EXPERT REPORT OF

WILLIAM P. ZARAKAS

ON BEHALF OF

BC HYDRO

August 17, 2021

TABLE OF CONTENTS

CONSIDERATIONS AND RECOMMENDATIONS FOR
COST BENCHMARKING TERMS OF REFERENCE

I. INTRODUCTION AND SUMMARY OF OPINION

A. NATURE OF THE ENGAGEMENT

1. I understand that BC Hydro has developed a proposed terms of reference for the use of regularly scheduled statistical cost benchmarking in its ongoing Revenue Requirements Applications. Specifically, the cost benchmarking that BC Hydro proposes includes:

   a. Cost and performance benchmarking of various detailed aspects of BC Hydro's transmission and distribution operations, following the approach and form of a report by First Quartile (dated December 10, 2020) which BC Hydro discussed in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application;

   b. Cost and performance benchmarking of generation facilities, following the approach and form of the Generation Knowledge Services report authored by Guidehouse (dated January 2020), which BC Hydro discussed in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application;

   c. Benchmarking of BC Hydro's compensation ("total rewards") for the range of employment levels, following the approach and form of the Morneau Shepell report (dated April 2018), which BC Hydro discussed in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application;

   d. Cost benchmarking of its operations and maintenance (O&M) costs, similar to the approach and format that The Brattle Group used in a prior analysis and discussed in BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (Appendix T); and

   e. A review of BC Hydro's operating costs compared to other Canadian integrated electric utilities, substantially in the form of the study which BC Hydro provided as part of the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (Appendix U).

2. BC Hydro has requested that I review the above referenced studies and provide my opinion concerning:

a. The value or appropriateness of the reports in total as an overall suite of benchmarking studies, developed with the purpose of improving BC Hydro's performance in the subject areas, and also to inform the review of cost forecasts in regulatory proceedings;

b. The appropriateness of the proposed frequency of the reports;

c. Whether the design, peer groups and data sets used in the previous iterations of items (d) and (e) above remain appropriate as predetermined parameters for future statistical cost benchmarking reviews.

3. Also, BC Hydro requested that I provide my assessment of the suggestions put forward by other parties in recent proceedings with regard to statistical cost benchmarking, including:

   a. Annual reporting metrics to track historical trends and discontinuities as suggested by RCIA in Table 1 of its Final Argument in the proceeding to review BC Hydro's PBR Report;

   b. Multi-dimensional indexes and econometric models as described by Dr. Mark Lowry in his September 8, 2020 presentation during the proceeding to review BC Hydro's PBR Report; and,

   c. A total factor productivity study to establish a productivity factor to assess the reasonableness of cost forecasts, as explored by BCOAPO IR 1.9.1 during the proceeding to review BC Hydro's PBR Report.

4. The letter of instruction pertaining to this engagement is included as an Appendix to this report.

B. SUMMARY OF OPINIONS

5. BC Hydro requested that I provide my opinion concerning the appropriateness of its proposed suite of cost benchmarking studies for inclusion as terms of reference in Revenue Requirement Applications (RRAs) that it may have before the BCUC. I understand that BC Hydro is putting forward the proposed terms of reference so that the BCUC can assess the utility's relative level of operating efficiency, and possibly use these data to adjust the costs that BC Hydro includes in its RRA if warranted.

6. I considered various factors in assessing whether BC Hydro's proposed cost benchmarking terms and conditions are appropriate for the subject task, primarily including whether they provide meaningful information to the BCUC during proceedings involving Revenue Requirements Applications, and whether the benchmarking studies are useful to BC Hydro managers in their efforts to continually improve the utility's processes and performance. I also considered whether the methodologies and data underlying the benchmarking studies were sufficiently transparent and replicable.

7. I considered two broad types of statistical cost benchmarking methodologies. The first type follows the unit cost benchmarking methodology, which involves selecting and then comparing cost performance metrics for BC Hydro against a panel of peer utilities. Examples include the First Quartile, Guidehouse and Brattle reports listed above. The second type involves more statistically complex benchmarking models that use data from a panel of peer utilities to parameterize utility cost drivers and operating scale in order to estimate BC Hydro's relative efficiency level as a single value.

8. The unit cost benchmarking approach is transparent, understandable and replicable. Furthermore, aggregate metrics (e.g., total operations and maintenance costs) can be disaggregated, so that specific performance areas can be examined and opportunities for performance improvements can be identified. The primary criticisms of the unit cost benchmarking approach is that:1) this effort usually produces multiple metrics that do not necessarily roll up neatly into a single efficiency value; and 2) the approach relies on imperfect peer panels which may distort the relative efficiency of the utility being benchmarked.

9. The primary virtue of the more statistically complex benchmarking (i.e., econometric based modeling) is that the end result is a single number that ostensibly reflects the subject utility's relative level of cost efficiency. Furthermore, proponents of these statistical methods contend that the resulting efficiency indicator accounts for unique cost drivers and the multiple dimensions of utility operations, and ensures that comparisons with other utilities are accurate. However, econometric benchmarking studies also necessarily rely on imperfect peer panels as well as on several more technical assumptions, which leads to considerable debate among experts with respect to functional form, computational approaches, and other modeling decisions.

Furthermore, the resulting efficiency rating is considered “black box” information to utility managers and does not provide them information relevant to their own process improvement efforts.

10. I find that BC Hydro’s proposed terms of reference is appropriate for the BCUC to adopt because the proposed suite of studies are more transparent, understandable and replicable than the alternative econometrically based cost benchmarking studies. In addition, BC Hydro’s proposed suite of benchmarking studies provides value to BC Hydro’s managers and is informative to the BCUC in their review of cost forecasts during the Revenue Requirements Application process. BC Hydro’s proposed suite of benchmarking studies can also be updated on a regular basis, which will allow the BCUC to have access to current data and analysis during its deliberations.

II. QUALIFICATIONS

11. I am William P. Zarakas. I am a Principal with The Brattle Group, an economics consulting firm. I hold a leadership position in Brattle’s Retail Energy Practice, and I lead much of Brattle’s project work in the areas of performance based regulation, cost analysis and benchmarking, utility business models, benefit-cost analyses (e.g., grid modernization, reliability and resilience) and rate and pricing analyses. I also work on economic and regulatory matters in the telecommunications industry, including the economics and financial feasibility of building out broadband infrastructure and regulatory matters concerning network access and pricing. I have also provided expert testimony on cost benchmarking that was included as Appendix T in BC Hydro’s Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.[1]

12. I have provided testimony and expert reports on matters concerning electric utility regulatory frameworks and approaches and cost analyses, as well as competition and regulatory issues in the telecommunications industry. My testimony and expert reports have been presented before the Federal Energy Regulatory Commission (FERC), state regulatory commissions, the Federal Communications Commission (FCC), the Securities and Exchange Commission (SEC), the

---

1 British Columbia Utilities Commission – Review of British Columbia Hydro and Power Authority’s Performance Based Regulation Report – Project No. 1599045, British Columbia Hydro and Power Authority Fiscal 2020 to Fiscal 2021 Revenue Requirements Application, Appendix T (“Brattle Report”).

Copyright Royalty Judges (Library of Congress), the U.S. Congress, arbitration panels, and courts of law. I have also authored reports concerning special investigations on behalf of corporate boards of directors and audits of management practices and operational and financial performance on behalf of regulatory commissions.

13. I hold an M.A. in economics from New York University and a B.A., also in economics, from the State University of New York. I have authored articles in industry periodicals and journals on economic and regulatory matters. I have also taken and instructed courses on economic and regulatory matters. My curriculum vitae is provided in Appendix B.

III. DUTY OF INDEPENDENCE

14. I understand that while I have been hired by BC Hydro, I have a duty to assist the Commission and that I am not to be an advocate for BC Hydro or any other party ("Duty of Independence").

15. I certify that I am aware of my Duty of Independence, and that I have prepared my report in accordance with that Duty of Independence. Furthermore, I certify that if I am called to give oral or written testimony, I will give that testimony in conformity with the Duty of Independence.

IV. ISSUES

A. CONTEXT

16. In its broadest sense, benchmarking refers to the comparison of one party's performance and/or processes in a specified area to an external standard or to the performance of peers. Frequently, the purpose of a benchmarking exercise is for a firm to self-assess its performance and identify areas for improvement. Benchmarking of costs and/or service quality may also be used by regulators (of utilities) to assess the performance of the firms under their jurisdiction.

17. The overall efficiency of a firm (in this case, an electric utility) is a function of the amount and combination of the inputs that it uses (in its production process) to the outputs that it ultimately generates. Inputs include labor, materials, rentals and services, as well as the deployment of capital assets, which are substantial for capital intensive industries such as electric utilities.

Capital assets are particularly challenging to address in a benchmarking exercise because deployed capital is acquired at a specific point in time but delivers a flow of service over many subsequent time periods. Capital therefore needs to be imputed in order to reflect an annualized number, which requires a range of assumptions and modeling techniques. This presents a sizable challenge with respect to completing a study of the overall efficiency of a utility (such as BC Hydro) compared to a set of comparable utilities. Thus, many cost benchmarking studies are frequently prescribed to specific areas of utility operations.[2]

18. BC Hydro has proposed that a suite of five cost and performance benchmarking studies be adopted as terms of reference for the use of regularly scheduled statistical cost benchmarking in its ongoing Revenue Requirements Applications. Two studies in the suite (the Brattle study and BC Hydro's cost comparison analysis) provide high level cost benchmarking of BC Hydro's non-fuel operations and maintenance (NFOM) costs, with the Brattle study benchmarking BC Hydro against a panel of US electric utilities that are of similar size and hydroelectric generating capacity, and BC Hydro's study providing an indicative comparison to other Canadian vertically integrated electric utilities. The First Quartile benchmarking study takes a deeper dive into transmission and distribution (T&D) operations and maintenance (O&M) costs as well as capital expenditures. The Guidehouse GKS Hydro study takes a similar approach, taking a deeper dive into hydroelectric generating station O&M costs and capital investments. Finally, the total rewards employee compensation benchmarking study takes a deep dive into labor costs, which constitute a large portion of BC Hydro's total O&M costs. The suite of benchmarking studies proposed by BC Hydro thus provide information and perspective on NFOM and on capital expenditure levels for hydro generation, transmission and distribution.

---

2 One analytic techniques that measures all of a firm's inputs and outputs is Total factor productivity (TFP), an analytic element that is frequently considered in determining the X factor (i.e., productivity offset) in the index (i.e., I-X) approach to multiyear rate plans. But even here, TFP measures the difference between the growth rates of a firm's physical outputs and physical inputs; it does not provide the relative rankings of an individual firm's efficiency compared to a panel of peers. Also, TFP analysis requires application of "advanced theoretical techniques to combine disparate inputs and outputs into single input and output indexes suitable for comparison to one another." Makholm, J., Ros, A., & Case, M. *Total factor productivity and performance-based ratemaking for electricity and gas distribution*. Presented at the 31st Annual Eastern Conference of the Center for Research in Regulated Industries.

19. Approaches to cost benchmarking range from comparisons of disaggregate unit cost metrics (e.g., substation maintenance cost per customer) to benchmarking based on considerably more complex statistical applications, such as econometric cost function modeling, stochastic frontier analysis and data envelopment analysis.

20. The five cost benchmarking studies referenced above are examples of unit cost benchmarking, which involves compiling relevant and consistent data for a peer group of utilities that, ideally, have similar cost drivers and face similar business issues. This type of cost benchmarking is widely used by utility managers in assessing performance and identifying opportunities for improvement. The cost metrics themselves tend to be straightforward, easy to understand and directly applicable to the utility business area under study. Finally, comparing unit costs (e.g., per customer and/or per kWh) allows for comparisons across utilities of different sizes – although this is not a perfect solution for adjusting for scale effects.

21. The more statistically complex cost benchmarking approaches referenced above involve estimating a level of efficiency (with respect to total costs or a subset thereof) after taking account of cost drivers and scale factors using econometric modeling techniques.[3]

    a. Under the econometric approach, historical operating data from a group of utilities are used to estimate the parameters of a model, which are then used to generate a cost benchmark for the utility under study, where that benchmark aims to account for the subject utility's specific circumstances.

    b. The use of a multi-dimensional scale index is similar to the econometric approach discussed above, but generates an efficiency measure that takes into account multiple dimensions of scale (*i.e.*, the number of customers, generating capacity, and net generation) but not other cost drivers.

22. These types of analyses are less intuitive than the unit cost benchmarking described earlier. While they may be used by some regulatory commissions as part of index-based rate cases (*e.g.*,

---

3 *See*, for example, Mark Newton Lowry, Review of British Columbia Hydro and Power Authority's Performance Based Regulation Report, September 9, 2020, ("Lowry Presentation") at 11-17.

I – X), they are infrequently used by utility managers themselves in assessing the utility's performance or its processes, or in associated improvement efforts.

23. The end result of these types of statistical cost benchmarking involves an estimate of how close (or how far off) the subject utility's cost performance is compared to the peer panel reference point (e.g., average or top quartile). Examples of such results were shown in Dr. Lowry's presentation to the BCUC (submitted September 9, 2020) in which he showed the cost efficiencies for 59 electricity distributors in Ontario. There, distribution utilities are ranked based on their difference from the econometric study benchmark, with cost efficiency levels below the benchmark indicating higher performance.[4]

B. BC HYDRO'S PROPOSED COST BENCHMARKING STUDIES

24. Three of the cost benchmarking studies proposed by BC Hydro are "subscription" services. That is, they are benchmarking studies performed by external consulting firms that take a deep dive into specified areas of utility performance based on data sets compiled from publicly available information (e.g., FERC Form 1) and proprietary sources (e.g., surveys answered by participating utilities). These studies are performed regularly, frequently annually.

    a. First Quartile Consulting conducts an annual study on electric utility transmission and distribution (T&D) operations. In 2020, 27 utilities participated in First Quartile's T&D benchmarking study, including US investor owned and municipal electric utilities, Canadian utilities, one utility outside of North America and two utilities that participated only with respect to their transmission operations. The First Quartile report compares BC Hydro to the above peer group in a range of T&D cost areas, and provides information on how BC Hydro compares to the peer panel with respect to very detailed cost areas that may assist BC Hydro managers identify areas for highly specified performance improvement. These include, for example, spending on pole inspections and electric substation staffing levels.

---

[4] See Transcript from British Columbia Utilities Commission Workshop, September 8, 2000 at 233; *see* Mark Newton Lowry, Review of British Columbia Hydro and Power Authority's Performance Based Regulation Report, September 9, 2020, at 67-68.

b. GKS (Generation Knowledge Service) Hydro is a benchmarking study of approximately 500 hydroelectric stations with benchmarking study participants predominantly represented from the US and Canada, as well as other representation from Europe, New Zealand and South America. The most recent study was dated January 2020. The areas of hydro performance include operations, maintenance, investment, engineering and support; performance with respect to BC Hydro's Aberfeldie, Seton, Bridge River 1-2 and Mica hydro stations are compared to the GKS peer panel.

c. Morneau Shepell (now LifeWorks) completed an employee compensation benchmarking study for BC Hydro dated April 2018. The study benchmarked "total rewards" to employees, which includes cash compensation, incentive plans, health benefits, time-off provisions and flexible work arrangements for the full range of BC Hydro employees, from IBEW employees through senior managers and directors. The total rewards study employed a panel of 15 peer companies selected by BC Hydro (but which are redacted in the study for purposes of confidentiality). The study found that with respect to total reward compensation: BC Hydro falls within +/- 10% of the market median for nine of the ten job categories; in one job category BC Hydro's total reward compensation is less than 90% of the market median; and in none of the job categories considered does BC Hydro's total reward compensation exceed 110%.

25. The remaining two studies referenced by BC Hydro provide a more aggregate analysis of BC Hydro's non-fuel operations and maintenance costs (NFOM). Specifically, the scope of these studies includes all of BC Hydro's operations and maintenance costs, except the costs of fuel and water rentals that are used in the power production process.

a. The Brattle Group cost benchmarking study compares BC Hydro to a utility peer panel of US electric utilities by way of a series of unit cost metrics, such as power production O&M costs per generated MWh and per customer, and non-power production O&M costs per delivered MWh and per customer. The Brattle cost benchmarking study also examined cost areas at a more disaggregated level, such as customer facing functions (composed of customer accounts, customer service and informational expenses, and sales), albeit at a less detailed level than a more focused benchmarking study. Brattle's analysis was based on US electric utilities because of the availability and consistency of operations and maintenance cost data provided by utilities in FERC Form 1 submissions. The utility peer panel to which the subject utility is compared is an important consideration. The peer panel for the Brattle study was selected based on a combination of utility size (as measured by delivered power) and hydro generating capacity. However, the Brattle study makes clear that there will be few cases in which utilities are fully similarly situated, which makes peer panels less than perfect.

Brattle's overall conclusion was that "BC Hydro's non-fuel operations and maintenance expenses … are comparatively lower than peer utilities, and in many cases fall in the first quartile, a sought-after position (from a cost perspective, assuming that the utility provides sufficient levels of service). Much of this strong showing is due to BC Hydro's strong unit cost performance in power production NFOM."[5] The Brattle analysis also found that BC Hydro showed strong performed even after excluding power production NFOM; specifically BC Hydro was in the first quartile with respect to the non-power production NFOM metric. BC Hydro had moved up from the second quartile of unit cost performance for this metric in the earlier years of the study period, mainly due to improvements in its cost performance in transmission and distribution.

b. In addition, BC Hydro prepared an indicative cost comparison, using similar metrics to those used by The Brattle Group but using publicly-available information on Canadian electric utilities FortisBC Inc., Manitoba Hydro, and Hydro Quebec as the peer panel. As indicated above, the scope of The Brattle Group's cost benchmarking study was limited to US electric utilities due to the availability of complete and consistent O&M cost data. Canadian electric utilities are not required to file such data, under a consistent accounting standard or otherwise. BC Hydro developed comparable operating cost data for these utilities by assessing each utility's operating costs, number of customers, and sales volume and making assumptions in order to align costs and ensure some degree of consistency. BC Hydro's cost comparison indicated that its costs were in line with those of the Canadian utility peer panel on both a per MWh and a per customer basis.

[5] Brattle Report, para. 53.

26. Brattle's NFOM cost benchmarking study and BC Hydro's operating cost review, together with the three deep dive benchmarking studies provide a relatively complete assessment of BC Hydro's comparative cost performance in these areas.

C. RELEVANT ISSUES

27. The usefulness and appropriateness of BC Hydro's proposed terms of reference concerning regularly scheduled statistical cost benchmarking – or the usefulness and appropriateness of alternate statistical cost benchmarking studies – depends on the BCUC's intended use of such information. I understand that BC Hydro has proposed the referenced suite of benchmarking in order to inform the BCUC in its assessment of BC Hydro's RRA cost forecast. In addition, the studies included in BC Hydro's proposed terms of reference are also applicable to the BCUC's review of alternate regulatory frameworks, such as one involving an I-X index.[6]

28. In the case of cost forecasts, a cost benchmarking study may provide information regarding the level to which BC Hydro is an efficient electric utility from an O&M perspective. In addition, the T&D and hydro generation studies also provide information benchmarks concerning BC Hydro's capital spending in these areas.

29. In the discussion below, I assess whether BC Hydro's proposed terms of reference concerning regularly scheduled statistical cost benchmarking studies are appropriate and provide sufficient value to assist in BC Hydro's efforts to continuously improve its O&M performance and also are appropriate and provide value to the BCUC in its review of cost forecasts in regulatory proceedings. I will also address the appropriateness of BC Hydro's proposed reporting schedule and the appropriateness of the peer panels and data used in the NFOM studies performed by The Brattle Group (of US electric utilities) and BC Hydro (of select Canadian electric utilities).

---

6 With respect to indexed multi-year rate plans, cost benchmarking may inform the "stretch factor" that may be added to the I - X formula, resulting in a new formula of the form I - (X + Stretch). Specifically, a stretch factor may be used to account for a utility's relative efficiency at the onset of a PBR plan. A relatively inefficient utility may be subject to a high stretch factor (because it should be able to realize efficiencies that others in the industry have already realized), while a relatively efficient utility would be subject to a low (or perhaps no) stretch factor.

V. DISCUSSION

30. As indicated in Section I (A) above, BC Hydro requested that I assess and provide my opinion on whether the utility's proposed cost benchmarking studies provide value and/or are appropriate for purposes of: 1) enabling BC Hydro to improve its performance in the subject cost benchmarking areas; and, 2) to inform the review of cost forecasts in regulatory proceedings.

A. ENABLING BC HYDRO TO IMPROVE ITS PERFORMANCE

31. The three deep dive cost benchmarking studies that BC Hydro included as part of the proposed terms of reference were initiated by BC Hydro's managers – outside of any regulatory considerations – for the purpose of allowing them to better understand and improve upon the utility's performance with respect to T&D operations, hydro generation operations and employee compensation.[7] The focus of these benchmarking studies are therefore, and understandably, sufficiently granular in order for BC Hydro's managers to identify specific and actionable areas of improvement. BC Hydro will almost certainly continue to participate in these cost and performance benchmarking studies, irrespective of regulatory reporting requirements. This also means that including these studies in the terms of reference will not add additional costs in order to comply with regulatory requirements.

32. The more aggregated NFOM studies (i.e., the Brattle cost benchmarking study using US utilities and BC Hydro's review of the operating costs of other Canadian integrated electric utilities) are also of value to BC Hydro's managers in improving operations, albeit less so than the disaggregated and focused benchmarking studies referenced above. I understand that these two cost analyses were developed primarily to convey BC Hydro's overall level of operational efficiencies to the BCUC in a prior regulatory proceeding. Nonetheless, these studies highlight how the granular cost areas come together to affect BC Hydro's overall financial performance.

33. The Brattle and BC Hydro cost analyses are understandable to BC Hydro managers, who routinely examine cost drivers. These managers may also contribute to improving peer panels or other aspects of the analysis based on their experience and understanding of the utility business

[7] These efforts are sometimes referred to as "continuous improvement."

and their familiarity with other utilities. In contrast, the econometric and/or multidimensional scale index approaches discussed above provide black box indicators of BC Hydro's relative cost efficiency, which BC Hydro's managers would have to accept on faith. Similarly, an econometric study that arrives at a single efficiency measure covering multiple functional areas of the utility provides little actionable information to managers or regulators. It does not highlight areas for potential improvement, or areas where the utility's performance is already satisfactory or better.

B. INFORMING REGULATORY PROCEEDINGS

34. The aggregate NFOM cost benchmarking studies, with the supporting disaggregate cost and performance benchmarking studies discussed above, also provide sufficient information to regulators in assessing BC Hydro's relative cost efficiency – and are accordingly valuable and appropriate in this regard. A particularly relevant question is whether these studies provide greater relevance to the BCUC in regulatory reviews than do alternate cost benchmarking studies, notably those relying on econometric or multidimensional scale index based approaches.

35. A key argument espoused by proponents of the econometric and index approaches to statistical cost benchmarking, is that the end result is a single number that reflects a utility's relative level of cost efficiency.[8] Proponents of these statistical methods contend that the resulting efficiency indicator accounts for unique cost drivers and the multiple dimensions of utility operations (e.g., scale, delivery and generation volume, transmission and distribution line lengths, and customers served), ensuring that comparisons with other utilities are accurate. As a corollary, these proponents also contend simpler forms of cost benchmarking, notably the unit cost approach used by Brattle and BC Hydro in their respective NFOM studies, do not fully account for these factors, leading to less reliable results.

36. However, econometric benchmarking studies also necessarily rely on assumptions with respect to functional form, computational approaches, and other modeling decisions. The resulting studies are also subject to considerable criticism among experts who debate arcane statistical and econometric concepts. For example, as part of a regulatory proceeding involving determination

[8] *See, e.g.*, Pacific Economics Group Research LLC. Review of BC Hydro's PBR Report. September 8, 2020.

of a multiyear revenue requirements for distribution network service providers (DNSPs), the Australia Energy Regulator retained an economic consulting firm to estimate relative DNSP efficacy levels using a statistical cost benchmarking approach. The resulting efficiency levels were challenged by some DNSPs who argued that the multilateral total factor productivity index approach used by the AER's consultant was inappropriate and that other techniques (such as a least squares translog model) were better suited to the circumstances at hand.[9]

37. Thus, any efficiency measure estimated under econometric and/or index approaches is far from indisputable and requires judgement in its own right. It is not surprising, then, that when determining which approach to take concerning the stretch factor in an index-based rates plan – which, as discussed above, is informed by cost efficiency analysis – the Alberta Utilities Commission concluded that "the determination of the size of a stretch factor is, to a large degree, based on a regulator's judgement and regulatory precedent and does not have a 'definitive analytical source' like the TFP study represents."[10]

38. Unit cost type benchmarking studies, including that conducted by The Brattle Group, also involve judgement, particularly in the selection of a utility peer panel.[11] The selection of a peer panel combined with the denominator of the unit metrics considered (e.g., per customer, per delivered kWh, per generated kWh, etc.) are the mechanisms used in unit cost based benchmarking to address the cost driver, scale and business condition considerations discussed above. Unit cost benchmarking results provide indications of relative efficiency, with the caveat that the definition of "relative" can be somewhat sensitive to the composition of the peer panel, which in itself is constrained by the availability of data from other utilities.[12] Unit cost

---

9 Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs, prepared for Australian Energy Regulator, Economic Insights Pty Ltd, 17 November 2014. Statistical Benchmarking for NSW Power Distributors, Pacific Economics Group Research LLC, 19 January 2015.

10 The Alberta Utilities Commission Decision 2012-237: Rate Regulation Initiative Distribution Performance-Based Regulation Application No. 1606029 Proceeding ID No. 566 September 12, 2012. Para 497.

11 "Ideally, the utilities included in a benchmarking peer panel should be relatively similar to the utility under study, however, perfect matches are rarely achieved. Nonetheless, selecting a reasonable peer panel is a particularly important part of cost benchmarking—for somewhat obvious reasons. Selecting inefficient or otherwise high cost utilities for a peer panel—intentionally or otherwise—may make the utility under study appear more efficient than it actually is, and vice versa. Accordingly, considerable attention is afforded the peer panel selection process." Brattle Report, para. 23.

12 The results of econometric or index-based approaches to benchmarking can also be sensitive to the composition of the peer panel, and are similarly constrained by data availability.

benchmarking studies may also be improved over time as participating parties – utility managers or otherwise – provide input into the peer panel selection process.

39. With respect to the cost benchmarking of BC Hydro's NFOM costs against US utilities (following the approach and format used by The Brattle Group):

The design, data set and peer groups are appropriate to apply to future cost benchmarking studies and to include in the terms of reference for the use of regularly scheduled statistical cost benchmarking in ongoing Revenue Requirements Applications. However, I also note that this cost benchmarking is an ongoing and evolving process. The above framework should be modified if participants provide insight and/or information that could improve it, particularly with respect to the peer panel.

40. With respect to BC Hydro's review of operating costs of Canadian integrated electric utilities (following the approach and format used by BC Hydro):

The data set and peer groups are limited by the aforementioned unavailability of consistent and comparable data. Understanding this limitation, the design, data set and peer groups are appropriate to apply to future reviews and to include in the terms of reference for the use of regularly scheduled statistical cost benchmarking in ongoing Revenue Requirements Applications. For this case, the framework should be updated as additional data becomes available for BC Hydro peers, particularly if new data allow for the inclusion of additional Canadian integrated electric utilities.

41. With respect to the performance and cost benchmarking of BC Hydro's T&D operations, generation facilities and total rewards compensation (following the approach and format used by First Quartile, Guidehouse and Morneau Shepell, now LifeWorks):

These benchmarking studies are specialties of the sponsoring firms, have evolved over many years and are improved on an ongoing basis. My review indicates that the design, data set and peer groups are appropriate to apply to future cost benchmarking studies and to include in the terms of reference for the use of regularly scheduled statistical cost benchmarking in ongoing Revenue Requirements Applications. However, the design, data sets and peer groups likely are modified on an ongoing basis in response to new information and insight and changes in participating utilities. Accordingly, I defer to the judgements of the sponsoring firms as to the future design, data and peer groups used in these studies.

42. BC Hydro also requested that I provide my opinion with respect to the appropriateness of how frequently the various benchmarking reports will be provided to the BCUC. Two of the subject benchmarking reports (First Quartile's benchmarking study of T&D operations and Guidehouse's GKS Hydro benchmarking study) are conducted, and will likely continue to be conducted, on an annual basis. Thus, these studies should be made available to the BCUC for review during the course of each of BC Hydro's Revenue Requirements Application.

43. The remaining three studies – the Brattle NFOM cost benchmarking study, the BC Hydro operating cost review and Morneau Shepell's (now LifeWorks') total reward benchmarking study – were conducted at the request of BC Hydro and, to my knowledge, are not part of an ongoing annual update. For these studies, BC Hydro should consider periodically updating Brattle's NFOM cost benchmarking study of US electric utilities in Revenue Requirements Applications to reflect the most current utility data reported to FERC. Such updates may be performed by BC Hydro, Brattle, or another consulting firm.

44. As indicated earlier (and discussed in Appendix U of BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application), BC Hydro's review of Canadian integrated electric utility operating costs involved considerable effort to gather and compile data and ensure consistent application. Unlike the updating and systemization associated with the other benchmarking studies in BC Hydro's proposal, limited data availability make it so that updating the review of Canadian utilities will likely continue to be labor intensive and continue to require revisiting assumptions. Regular updates of this study would likely be of value to the BCUC in its review of BC Hydro's future Revenue Requirements Applications. However, the factors above need to be taken into account when setting an update schedule.

45. Updated results for LifeWorks' total reward benchmarking study may also be informative to the BCUC when it is reviewing the costs provided by BC Hydro in its Revenue Requirements Applications. LifeWorks data sets are proprietary; I have no visibility into how frequently they are updated. I defer to LifeWorks to determine whether frequent updates of this study are cost effective.

C. ASSESSMENT OF SUGGESTIONS MADE BY OTHER PARTIES

46. BC Hydro requested that I provide my assessment of the suggestions put forward by other parties in recent proceedings with regard to statistical cost benchmarking, specifically suggestions and recommendations raised by Residential Consumer Intervener Association (RCIA), BCUC Staff's independent consultant (Dr. Mark Lowry) and the British Columbia Old Age Pensioner's Organization (BCOAPO) et al.

47. RCIA has suggested that BC Hydro report on roughly 25 performance metrics that cover various aspects of O&M costs, capital expenditures and the number of employees in specified areas (i.e., full time equivalents or FTEs). In addition, RCIA proposed that BC Hydro report on historical trends (e.g., last 10 years) and forecasts for system reliability (i.e., SAIDI and SAIFI), customer rates, and capital spending.

48. I have reviewed performance metrics and performance incentive mechanisms (PIMs) in various jurisdictions and found that, while there is no standard for the number of metrics or PIMs reported, practical considerations suggest that such tracking should start off at a simple and manageable level, and address priority issues. Not all of the measures on RCIA's list are necessarily efficiency type metrics (e.g., dollars in deferral accounts as a percentage of total O&M dollars). However, with respect to RCIA's proposed metrics that address BC Hydro's relative efficiency as a utility, the performance and cost benchmarking studies proposed by BC Hydro provide detailed information on many of the areas raised by RCIA, albeit in a different format (e.g., the First Quartile report includes historic metrics with respect to T&D capital expenditures and O&M costs). BC Hydro and the BCUC can consider modified and/or additional metrics as they gain experience in benchmarking and metrics reporting.

49. Also, RCIA's proposal primarily involves metrics that track BC Hydro's own current and historic performance. This makes it easier to acquire the necessary data than would be the case under a peer panel approach to benchmarking – although compiling these metrics would require additional (and potentially significant) effort on the part of the BC Hydro.[13] Tracking a utility's

---

[13] As indicated earlier, Canadian electric utilities do not report cost and performance data under a consistent accounting standard or otherwise. Also, for US electric utilities, data necessary to fill in the metrics for several of the metrics proposed by RCIA are not directly available in public filings and/or would require additional research and consistency checking – beyond that required for the metrics included in the Brattle report.

own historic performance provides a view of trends, but it does not necessarily fulfill the goal of assessing the utility's relative level of efficiency by sizing it up against peers, and therefore may not provide a full picture of industry trends. For example, a decline in cost performance may be due to increases in input prices that affect the entire industry, not just the utility under study. Focusing solely on BC Hydro's own historic performance may also present disincentives concerning performance improvement; *i.e.*, it may be reluctant to improve performance if it expects that it may have trouble continuing to meet that level on an ongoing basis. As a result, it is reasonable for BC Hydro to focus its efforts on the peer-based suite of benchmarking studies it has proposed.

50. BCUC Staff's independent consultant, Dr. Mark Lowry, provided a range of recommendations concerning possible features and applications of a performance based regulatory (PBR) framework as part of the Commission's Review of British Columbia Hydro and Power Authority's Performance Based Regulation Report – Project No. 1599045. In his discussion of the possible adoption of an I – X framework, Dr. Lowry recommended that BC Hydro's relative level of efficiency be estimated using econometric or indexed based models, which are applications of statistical cost benchmarking. The resulting efficiency level would inform the selection of a "Stretch" or "S" factor, which I described earlier,[14] and would be incorporated into the I – X framework. Specifically, the annual rate (or revenue) adjustment formula would be I – (X + S), with the additional possibility of other factors also be introduced into the formula (e.g., Y, K and Z among others).

51. Earlier in this report, I discussed that despite the virtue that the econometric and index approaches would produce a single relative efficiency number for BC Hydro, these modeling techniques are highly technical and involve considerable expert judgement. For business purposes, the resulting efficiency number is produced via a "black box" that is not accessible or understandable to most utility managers – so cannot be expected to be used in an actionable way to improve BC Hydro's operations. There is also uncertainty among regulators as to the merits of directly translating the efficiency levels produced by econometric or index models into an S factor, with Alberta Utilities Commission concluding that size of a stretch factor is based more

[14] See FN 6.

on judgement than the output of a statistical cost benchmarking model. Furthermore, the measure of relative efficiency produced by the econometric and index approaches provides little information to the BCUC concerning the specific areas of BC Hydro underperformance, if that were to be the case.

52. I understand that in the current context, BC Hydro is proposing to use cost benchmarking studies to inform the BCUC of its relative O&M cost performance and not proposing an I – X framework or an associated S factor. In this regard, BC Hydro's proposed benchmarking studies will provide sufficient and meaningful information to the BCUC. BC Hydro's proposed benchmarking studies will also be more transparent and understandable than the econometric and index based statistical cost benchmarking models that were recommended to estimate an S factor.

53. BCOAPO raised a question (in Information Request No. 1.9.1, including Nos. 1.9.1.1 though 1.9.1.3.2, dated: January 7, 2021) concerning whether the X factor is a form of statistical benchmarking, whether it can provide an external benchmark for BC Hydro's performance, and whether it can be used to establish an appropriate cost forecast for use in a MYRP or cost of service regulation (COSR) based rate plan.

54. In general, the X factor reflects the *average* historic productivity trends (i.e., changes in inputs per unit of output) for a peer group of utilities, compared to the economy overall. Thus, the X factor differs from statistical cost benchmarking, which is concerned with determining *relative* levels of cost efficiency. The X factor may be able to be used to determine the appropriate forecast of BC Hydro's costs, but it is not intended for that purpose. Instead, it would be more appropriate to review the cost benchmarking analysis that is used to inform the S factor, described earlier, and incorporate consideration of BC Hydro's relative level of operating efficiency into forecasts of BC Hydro's O&M costs.

APPENDIX A:

LETTER OF INSTRUCTION

FASKEN

Fasken Martineau DuMoulin LLP
Barristers and Solicitors
Patent and Trade-mark Agents

550 Burrard Street, Suite 2900
Vancouver, British Columbia V6C 0A3
Canada

T +1 604 631 3131
+1 866 635 3131
F +1 604 631 3232

fasken.com

Matthew T. Ghikas
Direct +1 604 631 3191
Facsimile +1 604 632 3191
mghikas@fasken.com

June 19, 2021
File No.: 301539.00025/15275

Via Email
Privileged and Confidential

The Brattle Group, Inc.
One Beacon Street Suite 2600
Boston, MA 02108, US

Attention: Bill Zarakas and Nicholas Powers

Dear Sirs/Mesdames

Re: British Columbia Hydro & Power Authority ("BC Hydro") Application to the British Columbia Utilities Commission ("Commission") for Approval of Revenue Requirements and Rates for Fiscal 2023-Fiscal 2025 ("Regulatory Proceeding")

As you are aware, we act on behalf of BC Hydro in the above referenced Regulatory Proceeding. This letter of instruction confirms your engagement for the provision of an independent expert report to be introduced into evidence in that Regulatory Proceeding on the topic of regularly-scheduled statistical cost benchmarking. It outlines the issues to be addressed and provides some general guidance as to the format of your report.

Apart from our instructions below as to the issues to be addressed and the format of your report, the contents of your report are entirely for you in the exercise of your independent professional judgment. We are retaining you to provide independent expert evidence for the above captioned Regulatory Proceeding, not as an advocate for our client. The integrity of your conclusions is dependent upon your objectivity.

<u>Matters on Which Your Opinion is Requested</u>

BC Hydro has committed to developing a proposed terms of reference for regularly-scheduled statistical cost benchmarking going forward. BC Hydro's proposal is set out in the table below.

FASKEN

Item #	Type of Statistical Cost Benchmarking	Frequency
1	Comparisons across various maintenance categories, including distribution, transmission, vegetation and stations, to help compare performance and identify areas of opportunity in comparison to industry peers, substantially in the form of the First Quartile report dated December 10, 2020 which BC Hydro discussed in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.	Each Revenue Requirements Application (i.e., approximately every three years), starting with the Revenue Requirements Application covering fiscal 2026
2	Comparisons of cost and performance of generation facilities to define specific steps to improve the cost or performance of those facilities relative to other utilities, substantially in the form of the Guidehouse (formerly Navigant) Generation Knowledge Services report dated January 2020, which BC Hydro discussed in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.	Each Revenue Requirements Application (i.e., approximately every three years), starting with the Revenue Requirements Application covering fiscal 2026
3	An assessment of employee compensation relative to median market rates, substantially in the form of the Morneau Shepell report dated April 2018, which BC Hydro discussed in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.	Alternating Revenue Requirements Applications (i.e., approximately every five to six years), with the next reports being provided as part of the Revenue Requirements Application covering fiscal 2026
4	A cost benchmarking study of operations and maintenance costs against a peer panel of electric utilities, substantially in the form of the benchmarking report dated February 18, 2019 which you authored and which BC Hydro filed as part of the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (Appendix T).	Alternating Revenue Requirements Applications (i.e., approximately every five to six years), with the next reports being provided as part of the Revenue Requirements Application covering fiscal 2026
5	A review of the operating costs of other Canadian integrated electric utilities, substantially in the form of the study which BC Hydro provided as part of the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (Appendix U).	Alternating Revenue Requirements Applications (i.e., approximately every five to six years), with the next reports being provided as part of the Revenue Requirements Application covering fiscal 2026

You are requested to evaluate BC Hydro's proposal for future statistical cost benchmarking, considering any factors that you regard as relevant in your expert opinion. At a minimum, we would ask that you include discussion of:

FASKEN

- the value of appropriateness of the reports in total as an overall suite of benchmarking studies to improve performance and to inform the review of cost forecasts in regulatory proceedings;

- the appropriateness of the proposed frequency of the reports;

- whether the design, peer groups and data sets used in the previous iterations of 4 and 5 remain appropriate as predetermined parameters for future statistical cost benchmarking / review;

- your assessment of the following suggestions put forward by other parties in recent proceedings:

  - The annual reporting metrics to track historical trends and discontinuities as suggested by RCIA in Table 1 of its Final Argument in the proceeding to review BC Hydro's PBR Report.

  - Multi-dimensional indexes and econometric models as described by Dr. Mark Lowry in his September 8, 2020 presentation during the proceeding to review BC Hydro's PBR Report.

  - A total factor productivity study to establish a productivity factor to assess the reasonableness of cost forecasts, as explored by BCOAPO IR 1.9.1 during the proceeding to review BC Hydro's PBR Report.

<u>Documents and Information Provided</u>

A copy of each of the reports referenced above is being provided to you with this letter. BC Hydro has obtained approval from the authors of items #1-3 to provide the reports to you on the following basis: This letter confirms your agreement that, unless BC Hydro specifically indicates otherwise, these reports cannot be used for any purpose other than creating your report for BC Hydro. The prior reports cannot be used to support your work for other clients or your own internal research efforts.

Portions of the Morneau Shepell report being provided to you, including the names of the peer companies and peer-specific data, remains redacted to comply with confidentiality requirements required by Morneau Shepell. A summary of the redacted information is attached to this letter.

BC Hydro will make available any other information that you require for your analysis, subject to contractual limitations on our ability to disclose third-party benchmarking information. You can assume, for the purposes of your analysis, that information provided by BC Hydro is accurate.

<u>Overview of the Structure of Your Report</u>

We request that your independent expert report be set out consistently with the following structure.

FASKEN

A. Introduction and Summary of Opinion

Your introduction should

- reference the nature of your engagement as an independent expert as per this letter, and
- set forth, in a summary fashion, your independent expert opinion.

B. Qualifications

Please state your professional qualifications, technical education, training and experience. Explain how your expertise relates to the subject matter of your opinions. Your detailed *curricula vitae* should be attached as an appendix.

C. Duty of Independence

We confirm that you have a duty to assist the Commission and are not to be an advocate for any party ("Duty of Independence"). In this section of your report, we require that you certify the following:

- You are aware of your Duty of Independence,
- You have prepared your report in accordance with the Duty of Independence, and
- If called to give oral or written testimony, you will give that testimony in conformity with the Duty of Independence.

D. Issues

This section should set out the issues as posed in this letter.

E. Discussion

Under this heading, you should set out in full your independent objective opinions. You should provide the reasons for your opinions including reference to pertinent facts or assumptions, any research you conducted that led you to form the opinion, and any applicable technical or other documents, standards, guidelines, etc.

F. Conclusion

You may provide a conclusion if you wish.

Appendices

Please include this letter, and the *curricula vitae* of those people responsible for the content of your report, as appendices to your report. If additional instructions are required, then

FASKEN

supplementary letters of instruction from us should also be attached to your report. You may attach other documents or schedules that elaborate on, or are integral to your analysis.

In conclusion, if you have any questions with respect to the nature and scope of your engagement, please contact the writer at your soonest convenience.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

Matthew T. Ghikas
Personal Law Corporation

MTG/lh

cc Chris Sandve
Chief Regulatory Officer
BC Hydro

FASKEN

Attachment 1: Summary of Redacted Information in Morneau Shepell Report

There are 15 comparator organizations in the Morneau Shepell benchmarking study:

- Five of these companies are from the utilities sector from across Canada, and this group is comprised of a mix of vertically integrated, crown corporation, and investor-owned utilities. The number of employees range from approximately 2,500 to 10,000, with an average of about 5,000.

- Five of these companies are from the public sector in British Columbia, including government agencies, crown corporations and municipal organizations. These cover different businesses and services, and range in size from around 900 employees to 26,000 employees, with an average of about 7,500.

- Five of these companies are in the private sector. Most have a corporate presence across Canada, and are very active in British Columbia. The services provided by these companies include engineering, construction services, forestry, financial services and telecommunications. The size of these companies vary from approximately 2,500 to over 50,000.

APPENDIX B:

CURRICULUM VITAE OF WILLIAM P. ZARAKAS

WILLIAM P. ZARAKAS
Principal

Boston, MA | +1.617.864.7900 | Bill.Zarakas@brattle.com

William Zarakas is an expert on economic and regulatory matters in the telecom, media, and energy industries.

Mr. Zarakas holds a leadership role in Brattle's Telecommunications, Internet, and Media practice. He has provided expert reports and testimonies in a range of regulatory proceedings concerning the economic analysis of mergers among telecom carriers and media companies; competition in telecom markets; forbearance from price regulation; infrastructure access, sharing and pricing arrangements; the economics and financial feasibility of deploying broadband networks; analysis and valuation of wireless spectrum bands and holdings; and the distribution of royalties and retransmission fees in the cable and satellite TV industries.

Mr. Zarakas also leads much of Brattle's work related to evolving utility regulatory and business models, including the application of performance-based regulation (PBR) and regulatory reform and incentives designed to improve efficiencies and advance policy goals, such as decarbonization and customer engagement. He works extensively on benefit-cost analyses, particularly with respect to investments in grid modernization, reliability, resilience, and smartening the grid. He has authored a wide range of reports and articles on PBR, "utility of the future" visions and implementation, the utility platform and multi-sided markets, and competition in the retail electricity sector.

Additionally, Mr. Zarakas has led special investigations on behalf of corporate boards of directors, as well as audits of management practices and operational and financial performance on behalf of regulatory commissions. He has provided expert testimony and reports before the Federal Communications Commission, the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Copyright Royalty Judges (Library of Congress), the US Congress, state regulatory agencies, arbitration panels, and foreign governments and courts of law.

Competition and Antitrust. Recent work includes:

- Conducted merger simulation analysis, submitted testimony and provided ongoing support on the potential effects of the merger of mobile wireless carriers Sprint and T-Mobile, under review before the US Federal Communications Commission, the Department of Justice, and various state Attorneys General on behalf of DISH Network.
- Conducted merger analysis, submitted testimony and provided ongoing support on the potential effects of the merger of Sinclair Broadcast Group and Tribune Media, under review before the US Federal Communications Commission on behalf of DISH Network.
- Conducted merger analysis, submitted testimony and provided ongoing support on the potential effects of the mergers of Comcast-Time Warner Cable; AT&T-Time Warner; and, Disney-Fox.
- Conducted competitive analysis, submitted testimony, and provided expert support in a regulatory proceeding before the Federal Communications Commission on competition issues in dedicated internet bandwidth services, including possession of market power and assessment of market power abuse on behalf of Sprint Corporation.
- Analyzed effectiveness of retail competition in U.S. electricity markets.

- Analyzed market structure and degree of competition in U.S. retail telecom markets and authored expert reports with regard to Petitions for FCC to forbear from price regulating resale services and UNEs on behalf of Granite Telecom and Incompas.
- Analyzed acquisition price premium in merger of cross-state gas and electric utilities on behalf of TECO Energy, Inc., New Mexico Gas Company, Inc in a matter before the New Mexico Public Regulatory Commission.
- Analyzed prospective merger savings and divestiture losses for electric and gas utilities in merger applications before the U.S. Securities and Exchange Commission (SEC).

Spectrum Valuation and Due Diligence. Work includes:

- Led numerous analyses of the values of wireless spectrum in the U.S., Canada, the Middle East and North Africa (MENA), and other geographic markets. Scope of analyses included: PCS, AWS, 2.3-2.5 GHz, SMR, PLMR, IVDS, MSS and Big Leo spectrum bands, among others, for purposes of planning, transactional analysis, regulatory proceedings, domestic and international arbitration, and commercial litigation.
- Conducted analyses and authored expert reports concerning utility use of private networks vs. leased spectrum, and valuations of 900 MHz spectrum.
- Led due diligence of acquisition of spectrum holdings and telecom assets for major telecom carrier.
- Led due diligence of northwestern U.S. electric and gas utility on behalf of buyer; analysis included comprehensive sales, revenue, and operating and capital cost modeling and scenarios.

Telecom Regulatory and Compliance. Work includes:

- Analyzed and provided testimony in matters concerning acces and foreclosure of network elements and services.
- Developed cost and revenue models to estimate costs, feasibility and customer rates associated with deploying wireless broadband to Alaska and rural areas in the continental U.S. on behalf of GCI Communications for FCC proceedings regarding the Connect America Fund and Mobility Fund.
- Analysis and expert reports on matters concerning pole attachment rates before the FCC on behalf of electric utilities.
- Led comprehensive modeling concerning costs and rates for unbundled network elements (UNEs), undertaken in fulfillment of requirements associated with the Telecommunications Act of 1996, using the Total Element Long Run Incremental Cost (TELRIC) methodology

Utility Regulatory and Business Models. Analyzed, advised and/or testified on matters concerning regulatory frameworks, performance-based regulation (PBR) and utility business models, notably with respect to emerging competitive alternatives and network integration. Recent work includes:

- Analyzed implementation of New York's Reforming the Energy Vision by modeling the economics of the utility platform model, access pricing and financial impacts of retail competition on utility.
- Analyzed, advised and/or testified on matters concerning performance incentive mechanism (PIMs); e.g., analyses of: New York's "earnings adjustment mechanisms" on behalf of New York's six investor owned utilities) and performance measures and incentive structures on behalf of the Hawaiian Electric Companies.

- Surveyed and analyzed PBR frameworks and applications, including multi-year rate plans (MRPs), PIMs and other alternative regulatory mechanisms, including the U.K.'s "RIIO" model.
- Surveyed and analyzed regulatory approaches to setting electric distribution reliability standards around the world on behalf of the Australian Energy Market Commission (AEMC).
- Modeled multi-variate "utility of future" scenarios using system dynamic approach on behalf of utilities and industry groups.
- Advised Board of Directors of a major generation and transmission (G&T) cooperative and its member electric distribution cooperatives on matters concerning: asset valuations, risk management strategy, merger and acquisition options, and outlook for retail electric markets.

Infrastructure and Investment Analysis. Analyzed and testified on matters concerning infrastructure economics and financial feasibility. Work includes:

- Led benefit-cost and economic "break-even" analysis of utility system reliability and resilience investment using a value of lost load (VOLL) methodology on behalf of Public Service Electric & Gas Company (PSE&G).
- Conducted financial feasibility analysis concerning deployment of a broadband communications network for an Asian electric utility.
- Analyzed economics and financial feasibility of providing (wholesale) transport and (retail) broadband services for multiple U.S. electric utilities.

Management Analysis and Audits. Recent work includes:

- Led strategic organizational options analysis for the Board of Trustees of the Long Island Power Authority (LIPA).
- Led special investigations; e.g., economic analysis of "swap" transaction for the Special Committee of the Board of Directors of Global Crossing.
- Led management and/or regulatory audits of utilities and telecommunications carriers on behalf of state regulatory commissions Alabama, Kentucky, Maryland, New York and Pennsylvania.

Other Regulatory Analyses. Recent work includes:

- Led benchmarking studies of utility costs and regulatory practices.
- Analyzed markets for and costs of providing utility pole attachments.
- Calculated total factor productivity (TFP) and X factors in price regulation proceedings involving utilities before state regulatory commissions and incumbent telecommunications carriers before the FCC.
- Analyzed costs and value of retransmitted television programming in cable and satellite video markets on behalf of Music Claimants in proceedings involving distribution of royalty funds.
- Examined impact of regulatory fees and constraints on economic output in 22 countries in the Middle East and Africa for international mobile carrier.

Expert Testimony

Expert reports entitled Comments on Commissioner Anthony's Principles for Performance Incentive Mechanisms Before the Rhode Island Public Utilities Commission (May 7, 2020).

Declaration of William Zarakas Verizon Maryland LLC, Complainant v. The Potomac Edison Company, Defendant, in a Pole Attachment Complaint Before the Federal Communications Commission, Proceeding No. 19-355, Bureau ID No. EB-19-MD-009 (February 1, 2020)

Declaration of William Zarakas Verizon Pennsylvania LLC and Verizon North LLC, Complainants v. Metropolitan Edison Company, Pennsylvania Electric Company, and Penn Power Company, Defendant, in a Pole Attachment Complaint Before the Federal Communications Commission, Proceeding No. 19-354, Bureau ID No. EB-19-MD-008 (February 1, 2020)

Declaration of William P. Zarakas BellSouth Telecommunications, LLC d/b/a AT&T Florida, Complainant, v. Florida Power & Light Company, Respondent, in a Pole Attachment Complaint Before the Federal Communications Commission, Proceeding No. 19-187, Bureau ID No. EB-19-MD-006 (September 12, 2019).

Direct Testimony of William Zarakas In the Matter of the Application of Potomac Electric Power Company for the Authority to Implement a Multiyear Rate Plan for Electric Distribution Service in the District of Columbia, Formal Case No. 1156 (May 30, 2019); Second Supplemental Direct Testimony (January 21, 2020); Rebuttal Testimony (April 6, 2020).

Declarations of Coleman Bazelon, Jeremy Verlinda, and William Zarakas Before the Federal Communications Commission In the Matter of Applications of T-Mobile US, Inc. and Sprint Corporation for Consent to Transfer Control of Licenses and Authorizations, WT Docket No. 18-197

- May 1, 2019, Response to Israel, Katz, and Keating April 12, 2019 Declaration
- March 28, 2019, Response to Compass Lexecon February 20, 2019 Declaration and Mark McDiarmid March 6, 2019 Declaration
- March 25, 2019, Response to Applicants' February 7 Filings on Diversion Ratios
- March 18, 2019, Reply to Cornerstone's "Response to Dish's February 19 and 25 Submissions"
- February 19, 2019, Reply to Cornerstone "Response to Dish and CWA Comments"
- February 4, 2019, Network Model's Sensitivity to Millimeter Wave Adjustments
- January 28, 2019, Response to Applicant Filings on Diversion Ratios
- December 4, 2018, Further Reply Declaration of Coleman Bazelon, Jeremy Verlinda, and William Zarakas

Declaration (August 27, 2018) and Reply Declaration (October 31, 2018) of Joseph Harrington, Coleman Bazelon, Jeremy Verlinda, and William Zarakas Before the Federal Communications Commission In the Matter of Applications of T-Mobile US, Inc. and Sprint Corporation for Consent to Transfer Control of Licenses and Authorizations, WT Docket No. 18-197

"The Role of Competitive Bidding Based Prices in Determining the Rural Rate," William Zarakas and Augustin J. Ros, In the Matter of Promoting Telehealth and Telemedicine in Rural America, Before the Federal Communications Commission, WC Docket No. 17-130 (May 24, 2019).

Response to PC 51 Request for Comments, Prepared for Joint Utilities of Maryland, Prepared by William Zarakas, Sanem Sergici, Pearl Donohoo-Vallett, and Nicole Irwin in Exploring the Use of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company of Gas Company Before the Public Service Commission of Maryland, PC 51 (March 29, 2019).

Declaration of William Zarakas and Dr. Eliana Garces Before the Federal Communications Commission In the Matter of Tribune Media Company (Transferor) and Nexstar Media Group, Inc. (Transferee) Consolidated Application for Consent to Transfer Control, MB Docket No. 19-30 (March 18, 2019).

Expert Report of William P. Zarakas On Behalf of BC Hydro, BC Hydro Fiscal 2020—Fiscal 2021 Revenue Requirements Application to the British Columbia Utilities Commission (February 8, 2019).

Direct and Rebuttal Testimony of William P. Zarakas On Behalf of Public Service Company of Oklahoma Before the Corporation Commission of the State of Oklahoma In the Application of the Public Service Company of Oklahoma For an Adjustment To Its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service For Electric Service in the State of Oklahoma, Cause No. PUD 201800085 (September 21, 2018, February 5, 2019).

Declaration of William P. Zarakas Before the Federal Communications Commission In the Matter of Petition of USTelecom for Forbearance Pursuant to 47 U.S.C. § 160(c) to Accelerate Investment in Broadband and Next-Generation Networks WC Docket No. 18-141, Opposition of Granite to USTelecom's Forebearnace Petition (August 6, 2018).

Declaration of William P. Zarakas Before the Federal Communications Commission In the Matter of Petition of USTelecom for Forbearance Pursuant to 47 U.S.C. § 160(c) to Accelerate Investment in Broadband and Next-Generation Networks WC Docket No. 18-141, Opposition of Incompas, FISPA, Midwest Association of Competitive Communications, and the Northwest Telecommunciations Association (August 6, 2018)

Expert report on behalf of GCI Communications "Rate of Return Analysis of GCI's TERRA Network," by William P. Zarakas, Agustin J. Ros, and Nicholas E. Powers. Prepared for GCI Communication Corp., March 30, 2018, in connection with the FCC's investigation of the Rural Health Care Telecommunications Program.

Expert report on behalf of GCI Communications before the Federal Communications Commission, In the Matter of Connect America Fund and Universal Service Reform, WC Docket No. 10-90 and WT Docket No. 10-208A: analysis of the FCC's Rural Health Care Program Funding and Recipients, by William Zarakas, Augustin Ros, David Kwok, and M. Elaine Cunha, September 2017.

Declaration (August 7, 2017) and Reply Declaration (August 29, 2017) of William P. Zarakas and Jeremy A. Verlinda Before the Federal Communications Commission In the Matter of Tribune Media Company (Transferor) and Sinclair Broadcast Group, Inc. (Transferee), Consolidated Applications for Consent to Transfer Control, MB Docket No. 17-179.

Before the State of New York Public Service Commission In the Matter of Earnings Adjustment Mechanism and Scorecard Reforms Supporting the Commission's Reforming the Energy Vision, Case 16-M-0429, On Behalf of the New York Joint Utilities (Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation), Report: "Assessment of Load Factor as a System Efficiency Earnings Adjustment Mechanism," William Zarakas, Sanem Sergici, et. al. (February 10, 2017).

Declaration of William P. Zarakas Before the Federal Communications Commission In the Matter of Business Data Services in an Internet Protocol Environment, Investigation of Certain Price Cap Local Exchange Carrier Business Data Services Tariff Pricing Plans, Special Access for Price Cap Local Exchange Carriers, AT&T Corporation Petition for Rulemaking to Reform Regulation of Incumbent Local Exchange Carrier Rates for Interstate Special Access Services, WC Docket No. 16-143, WC Docket No. 15-247, WC Docket No. 05-25, RM-10593. Declaration of William P. Zarakas and Susan M. Gately (January 27, 2016); Supplemental Declaration of William P. Zarakas (March 24, 2016); Declaration of William P. Zarakas and Jeremy Verlinda (June 28, 2016, Attachment D to Comments of Sprint Corporation); Declaration of David E. M. Sappington and William P. Zarakas (June 28, 2016, Attachment E to Comments of Sprint Corporation); Further Supplemental Declaration of William P. Zarakas (August 9, 2016, Attachment A of Reply Comments of Sprint Corporation).

Declaration of William P. Zarakas Before the Federal Communications Commission In the Matter of Verizon Virginia. LLC and Verizon South, Inc., Complainants, v. Virginia Electric and Power Company d/b/a Dominion Virginia Power, Docket No. 15-90, File No. EB-15-MD-006 (November 18, 2015).

Declaration of William P. Zarakas and Matthew Aharonian in the United States Court for the District of Columbia Circuit United States Telecom Association, Petitioner, v. Federal Communications Commission and the United States of America, Respondents, Case No. 15-1063 (and consolidated cases) (May 22, 2015).

Declarations Before the Federal Communications Commission In the Matter of Application of Comcast Corporation, General Electric Company and NBC Universal, Inc. for Comcast to Assign or Transfer Control of Licenses, Federal Communications Commission, MB Docket No. 10-56. Analysis of the FCC's Vertical Foreclosure and Nash Bargaining Models Applied To The Proposed Comcast-Time Warner Cable Transaction (December 21, 2014) and Supplemental Declaration: Analysis of the FCC's Vertical

Foreclosure and Nash Bargaining Models Applied To The Proposed Comcast-Time Warner Cable Transaction (March 5, 2015).

Before the Public Utilities Commission of the State of Hawaii, In The Matter of Public Utilities Commission Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, Docket No. 2013-1041, On Behalf of the Hawaiian Electric Companies. Report: "Targeted Performance Incentives: Recommendations to the Hawaiian Electric Companies," Prepared For The Hawaiian Electric Companies, William P. Zarakas and Philip Q Hanser (September 15, 2014).

Before the New Mexico Public Regulatory Commission, In The Matter Of The Application of TECO Energy, Inc., New Mexico Gas Company, Inc. and Continental Energy Systems, LLC, For Approval of TECO Energy Inc.'s Acquisition of New Mexico Gas Intermediate, Inc. and For All Other Approvals and Authorizations Required To Consummate and Implement The Acquisition, Utility Case No. 13-00231-UT, On Behalf of TECO Energy, Inc., New Mexico Gas Company, Inc. and Continental Energy Systems, LLC, Joint Applicants (March 2014).

"Analysis of Benefits: PSE&G's Energy Strong Program," by Peter Fox-Penner and William P. Zarakas Before the New Jersey Board of Public Utilities In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Energy Strong Program, Docket No. EO13020155 and GO13020156 (October 7, 2013).

"Review and Analysis of Service Quality Plan Structure In The Massachusetts Department of Public Utilities Investigation Regarding Service Quality Guidelines For Electric Distribution Companies and Local Gas Distribution Companies." Philip Q Hanser, David E. M. Sappington and William P. Zarakas, Massachusetts D.P.U. 12-120 (March 2013).

"Alaska Mobile Broadband Cost Model, Before The Federal Communications Commission In The Matter Of Connect America Fund and Universal Service Reform – Mobility Fund. WC Docket No. 10-90 and WT Docket No. 10-208A." William P. Zarakas and Giulia McHenry (February 2013; updated May 2016, with David Kwok).

Expert Report of William P. Zarakas In The United States District Court For The Northern District of Florida MCI Communications Services, Inc., Plaintiff v. Murphree Bridge Corporation, Defendant, Case No. 5:09-cv-337 (February 19, 2010).

Testimony of William P. Zarakas Before The Copyright Royalty Judges, Library of Congress, Washington D.C. In The Matter of Distribution of the 2004 and 2005 Cable Royalty Funds, Docket No. 2007-3 CRB CD 2004-20 (June 1, 2009).

Declaration of William P. Zarakas In The Circuit Court of Fairfax County, Virginia In The Matter of Sharon Dougherty, Plaintiff Vs. Thomas J. Dougherty, Defendant Case No. CL 2007-008757 (October 2008).

Expert report Public Service Company of New Mexico vs. Smith Bagley, Inc. and Lite Wave Communications LLC In The United States District Court For The District of New Mexico (March 2007).

"Comparative Market Value Analysis of Upper 700 MHz Public Safety Spectrum" Before the Before the Federal Communications Commission In the Matter of The Development of Operational, Technical and Spectrum Requirements for Meeting Federal, State and Local Public Safety Communications Requirements Through the Year 2010, WT Docket No. 96-86 (June 2006).

"Analysis of Potential Lost Profits Associated With The Alleged Breach of Contract Between Orbcomm and Orbcomm Asia Limited" Before the American Arbitration Association (May 2006).

Expert report Before the Federal Communications Commission In Petition of ACS of Anchorage, Inc. Pursuant to Section 10 of the Communications Act of 1934, as amended, for Forbearance from Sections 251(c)(3) and 251(d)(1) In the Anchorage LEC Study Area, WC Docket No. 05-281 (January 9, 2006).

Letter report of William Zarakas and Dorothy Robyn Before the U.S. House of Representatives Committee on Energy and Commerce and the U.S. Senate Committee on Commerce, Science and Transportation regarding the value of wireless spectrum in the 700 MHz band (May 18, 2005).

Expert report in MCI WorldCom Network Services, Inc. v. MasTec, Inc. Before the United States District Court Southern District of Florida, Case No. 01-2059-CIV-GOLD (May 2002).

Direct and Rebuttal testimony Before the Federal Communications Commission In the Matter of Virginia Cable Telecommunications Association v. Virginia Electric and Power Company, d/b/a Dominion Virginia Power and Dominion North Carolina Power, PA No. 01-005 (December 21, 2001).

"Analysis Of The Economic Impact Of A Divestiture Of The Gas Operations Of Rochester Gas And Electric Corporation" Before the U.S. Securities and Exchange Commission included in Form U-1 Application/ Declaration Under The Public Utility Holding Company Act of 1935 in the combination of Energy East Corporation with RGS Energy Group, Inc. (June 20, 2001) in Exhibit J-1 (May 15, 2001).

"Analysis Of The Economic Impact Of A Divestiture Of The Gas Operations Of Sierra Pacific Resources" Before the U.S. Securities and Exchange Commission included in Form U-1 Application/ Declaration Under The Public Utility Holding Company Act of 1935 in the acquisition by Sierra Pacific Resources of Portland General Electric Company, 2000 in Exhibit H-1 (January 31, 2000).

"Analysis Of The Economic Impact Of A Divestiture Of The Gas Operations Of Energy East" Before the U.S. Securities and Exchange Commission included in Form U-1 Application/ Declaration Under The Public Utility Holding Company Act of 1935 in the combination of Energy East Corporation with CMP Group, Inc. and with CTG Resources, Inc. in Exhibit J-1 (October 29, 1999).

Supplemental Affidavit of William Zarakas Before the Supreme Court of the State of New York, County of Niagara in Village of Bergen, et al. vs. Power Authority of the State of New York, February 1999.

Direct (December 15, 1997) and Rebuttal (March 9, 1998) Panel Testimony of William P. Zarakas and D. Daonne Caldwell Before the North Carolina Utilities Commission In Re: Proceeding to Determine Permanent Pricing for Unbundled Network Elements, Docket No. P-100, SUB 133D.

Direct (November 3, 1997) and Rebuttal (November 25, 1997) Panel Testimony of William P. Zarakas and D. Daonne Caldwell Before the South Carolina Public Service Commission In Re: Proceeding to Review BellSouth Telecommunications, Inc.'s Cost Studies for Unbundled Network Elements, Docket No. 97-374-C.

Direct Panel Testimony of William P. Zarakas and D. Daonne Caldwell Before the Florida Public Service Commission In Re: Petition of AT&T, MCI, and MFS for Arbitration with BellSouth Concerning Interconnection, Rates, Terms and Conditions of a Proposed Agreement, Docket Nos. 960757-TP/960833-TP/960846-TP/960916-TP/971140-TP (November 13, 1997).

Direct (October 10, 1997) and Rebuttal (October 17, 1997) Panel Testimony of William P. Zarakas and D. Daonne Caldwell Before the Tennessee Regulatory Authority In Re: Contested Cost Proceeding to Establish Final Cost Based Rates for Interconnection and Unbundled Network Elements, Docket No. 97-01262.

Direct (August 29, 1997) and Rebuttal (September 12, 1997) Panel Testimony of William P. Zarakas and D. Daonne Caldwell before the Alabama Public Service Commission In Re: Generic Proceeding: Consideration of TELRIC Studies, Docket No. 26029.

Direct (April 30, 1997) and Rebuttal (September 8, 1997) Panel Testimony of William P. Zarakas and D. Daonne Caldwell before the Georgia Public Service Commission In Re: Review of Cost Studies, Methodologies and Cost-Based Rates for Interconnection and Unbundling of BellSouth Telecommunications Services, Docket No. 7061-U.

Diraect (July 11, 1997) and Rebuttal (September 5, 1997) Panel Testimony of William P. Zarakas and D. Daonne Caldwell Before the Louisiana Public Service Commission In Re: Review of Consideration of BellSouth Telecommunications, Inc.'s TSLRIC and LRIC Cost Studies to Determine Cost of Interconnection Services and Unbundled Network Components, to Establish Reasonable, Non-Discriminatory, Cost-Based Tariff Rates, Docket Nos. U-22022/22093.

Direct and Rebuttal Testimony Before the Virginia State Corporation Commission on Behalf of United Telephone - Southeast, Inc. and Centel Corporation (May 1994).

Direct and Rebuttal Testimony Before the Tennessee Public Service Commission on Behalf of United Telephone - Southeast, Inc., Docket No. 93-04818 (January 28, 1994).

Direct and Rebuttal Testimony Before the Florida Public Service Commission on Behalf of Southern Bell Telephone & Telegraph Company, Docket No. 920260-TL (December 10, 1993).

Direct and Rebuttal Testimony Before the Tennessee Public Service Commission on behalf of South Central Bell, Docket Nos. 92-13527 and 93-00311 (March 22 and March 29, 1993).

Papers,Publications and Presentations

Washington D.C. Performance Based Regulation Workshop, presented by William Zarakas, Sanem Sergici and Pearl Donohoo-Vallett, September 19, 2018.

Hawaii Public Utilities Commission Performance Based Regulation Workshop, PBR Tools and Experience Panel, "The Intersection of Utility Platforms and PBR," William Zarakas, Honolulu, HI, July 23-24, 2018.

"A New Face for PBR: Aligning Incentives in the Electric Utility Ecosystem" by William Zarakas, *Public Utilties Fortnightly*, December 2017.

"Two-sided Markets and the Utility of the Future: How Services and Transactions Can Shape the Utility Platform," by William P. Zarakas, *The Electricity Journal*, Volume 30 (2017) 43-46.

Performance Based Regulation: Plans Goals, Incentives and Alignment, by William Zarakas, Toby Brown, Léa Grausz, Heidi Bishop and Henna Trewn, prepared for DTE Energy, December 6, 2017.

PBR: Applications and Future, presented by William Zarakas to the Michigan PSC PBR Collaborative, Lansing, Michigan, November 8, 2017.

"DER Incentive Mechanisms as a Bridge to the Utility of the Future," by William P. Zarakas, Frank C. Graves and Heidi Bishop, presented at SNL Knowledge Center's Energy Utility Regulation Conference: Strategies for Profit and Reliability, December 14, 2016.

"Electric Utility Services and Evolving Platforms in the Mid-Atlantic Region," by William Zarakas, presented at the Mid-Atlantic Conference of Regulatory Utilities Commissioners (MACRUC) 20th Annual Education Conference, Williamsburg, VA, June 23, 2015.

"Growth Prospects and Shifting Electric Utility Business Models: Retail, Wholesale and Telecom Markets," by William P. Zarakas, *The Electricity Journal*, Volume 28, Issue 5, June 2015.

"Do We Need a New Way to Regulate Electric Utilities?," by William P. Zarakas, presented at the Energy Bar Association 2015 Annual Meeting, Washington, DC, May 6, 2015.

"Investing In Electric Reliability and Resiliency," by William P. Zarakas, presented at the NARUC 2014 Summer Meeting - Joint Electricity and Critical Infrastructure Committees, Dallas, TX, July 15, 2014.

"Utility Investments in Resiliency: Balancing Benefits with Cost in an Uncertain Environment," by William P. Zarakas, Sanem Sergici, Heidi Bishop, Jake Zahniser-Word and Peter S. Fox-Penner, *The Electricity Journal,* Volume 27, Issue 5, June 2014.

"Infrastructure and Competition in the Electric Delivery System," by William P. Zarakas, *The Electricity Journal*, Volume 26, Issue 7, September 2013.

"Low Voltage Resiliency Insurance, Portable small-scale generators could keep vital services on line during a major power outages," by William Zarakas, Frank Graves, and Sanem Sergici, *Public Utilities Fortnightly* September 2013.

"Finding the Balance Between Reliability and Cost: How Much Risk Should Consumers Bear?," by William P. Zarakas and Johannes P. Pfeifenberger, presented at the Western Conference of Public Service Commissioners, Santa Fe, NM, June 3, 2013

"The Utility of the Future: Distributed or Not?," by William P. Zarakas, presented at Advanced Energy 2013, New York, NY, April 30, 2013

"Rates, Reliability, and Region," by William P. Zarakas, Philip Q Hanser, and Kent Diep, *Public Utilities Fortnightly*, January 2013

"Approaches to Setting Electric Distribution Reliability Standards and Outcomes," by Serena Hesmondhalgh, William P. Zarakas, and Toby Brown, The Brattle Group, Inc., January 2012

"Analysis of Strategic Organizational Options for the Long Island Power Authority," by William P. Zarakas, Frank C. Graves, and Michael J. Beck, prepared for the Board of Trustees, Long Island Power Authority, October 2011.

"Measuring Concentration In Radio Spectrum License Holdings," by Coleman Bazelon and William Zarakas, presented at the Telecommunications Policy Research Conference (TPRC), George Mason University, September 26, 2009.

"Structural Simulation of Facility Sharing: Unbundling Policies and Investment Strategy in Local Exchange Markets," White Paper, July 2005 (with Glenn A. Woroch, Lisa V. Wood, Daniel L. McFadden, Nauman Ilias, and Paul C. Liu).

"Betting Against The Odds? Why broadband over power lines (BPL) can't stand alone as a high-speed Internet offering." Public Utilities Fortnightly, April 2005, pp. 41-45 (with Kenneth J. Martinian).

"The Impact of the Number of Mobile Operators on Consumer Benefit," White Paper, March 2005 (with Kenneth J. Martinian and Carlos Lapuerta).

"Wholesale Pricing and Local Exchange Competition", Info, Volume 6, Number 5, 2004, pp. 318-325 (with Lisa V. Wood and David E. M. Sappington).

"Regulatory Performance Measurement Plans and the Development of Competitive Local Exchange Telecommunications Markets", Working Paper, November 2003 (with David E. M. Sappington, Lisa V. Wood and Glenn A. Woroch).

"FCC Pole Attachment Rates: Rebutting Some of the Presumptions," presented to utility regulators, March 2003 (with Lisa V. Wood).

"The Concurrent Exchange of Fiber Optic Capacity and Services Between Global Crossing and its Carrier Customers," prepared for Special Committee on Accounting Matters of the Board of Directors of Global Crossing Ltd., January 2003.

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix Z

BC Hydro's Compliance Filing for the Fiscal 2022 Revenue Requirements Application

BC Hydro
Power smart

Chris Sandve
Chief Regulatory Officer
Phone: 604-623-3726
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

July 16, 2021

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: Project No. 1599164
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2022 Revenue Requirements Application (the Application)

BC Hydro writes in response to various Directives in BCUC Order No. G-187-21 to provide our Compliance Filing for the Fiscal 2022 Revenue Requirements Application which includes updated Financial Schedules as well as updated rate schedules.

As discussed further in section 3 of the attached filing, BC Hydro is also applying to establish the Low Carbon Fuel Credits Regulatory Account to implement Directive 26 of the Decision. BC Hydro submits that this new regulatory account is required so that the actual value of low carbon fuel credits flows back to BC Hydro's ratepayers.

For further information, please contact Joe Maloney at 604-623-4348 or bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Chris Sandve
Chief Regulatory Officer

fk/rh

Enclosure

BC Hydro
Power smart

Fiscal 2022
Revenue Requirements Application

Compliance Filing in Response to Order No. G-187-21 and Application to Establish the Low Carbon Fuel Credits Variance Regulatory Account

July 16, 2021

BC Hydro
Power smart

Table of Contents

List of Tables

List of Appendices

1 Introduction

On June 17, 2021, the British Columbia Utilities Commission (**BCUC**) issued Order No. G-187-21, providing its Decision on BC Hydro's Fiscal 2022 Revenue Requirements Application (**Decision**). The Decision directed adjustments to BC Hydro's revenue requirements for fiscal 2022. BC Hydro provides this filing in response to those Directives and to apply for a regulatory account – the Low Carbon Fuel Credits Variance Regulatory Account - which BC Hydro submits is necessary to implement Directive 26 so that the actual value of low carbon fuel credits flows back to BC Hydro's ratepayers (**Compliance Filing and Application to Establish the Low Carbon Fuel Credits Variance Regulatory Account**).

Specifically, this Compliance Filing and Application to Establish the Low Carbon Fuel Credits Variance Regulatory Account:

- Recalculates BC Hydro's revenue requirements based on the Panel's determinations in its Decision and provides revised Financial schedules to the Application (Appendix A) and updated rate schedules (Appendix B) reflecting the BCUC's Decision and accompanying Order. The recalculated revenue requirements result in a rate increase of 1.00 per cent for fiscal 2022 compared to the interim rate increase of 1.16 per cent approved by the BCUC on January 5, 2021.[1] For further information, refer to section 2 below.

  Appendix B provides updated Electric Tariff Rate Schedules that reflect a rate increase of 1.00 per cent and updated Open Access Transmission Tariff (**OATT**) rates for fiscal 2022. Included in Appendix B are a black-lined and a clean copy of the applicable Electric Tariff Rate Schedules and applicable OATT Rate Schedules. The source documents of the rate sheets are attached

1 Refer to BCUC Order No. G-1-21.

to the electronic version of this submission for stamping by the BCUC and return to BC Hydro; and

- Applies to establish the Low Carbon Fuel Credits Variance Regulatory Account to capture the difference between planned and actual revenues from low carbon fuel credits in a given year so that the actual value of low carbon fuel credits flows back to BC Hydro's ratepayers. Appendix C provides a Draft Order for the establishment of this regulatory account. For further information, refer to section 3 below.

2 Recalculation of Revenue Requirements and Updates to Financial Schedules

2.1 Directive 1 – Revised Rates and Financial Schedules

Directive 1 of the Decision directed BC Hydro to recalculate its revenue requirements based on the Panel's determinations in its Decision and to provide revised Financial schedules (Appendix A) and updated rate schedules (Appendix B).

As shown in Table 2-1 below, Directives 22, 24, and 26 result in adjustments to the revenue requirements for fiscal 2022. Directive 25 did not have an impact on the revenue requirements in fiscal 2022 as all of the costs related to electric vehicle charging stations, including depreciation, were removed from the revenue requirements in accordance with Directive 24.

On January 5, 2021, the BCUC approved an interim rate increase of 1.16 per cent. BC Hydro has calculated the impact of the adjustments to the revenue requirements noted above and determined that the revised fiscal 2022 rate increase is 1.00 per cent. Table 2-1 below provides a summary of the rate adjustments for each of these directives. Each adjustment is explained in further detail in the sub-sections that follow.

Table 2-1 Revised Fiscal 2022 Rate Increase Reflecting BCUC's Decision

Description	Directive	F2022 Revenue Requirement ($ million)	F2022 Rate Increase (%)	Refer to Section
Interim rate increase		**5,211.7**	**1.16**	
Amend fiscal 2022 interconnection revenue to $4.6 million, and increase associated operating costs	22	(0.5)	(0.01)	2.2
Remove fiscal 2022 electric vehicle charging stations costs	24 & 25	(2.7)	(0.05)	2.3
Suspend fiscal 2022 recovery of forecast Electric Vehicle Costs Regulatory Account Balance and associated interest	24 & 25	(5.0)	(0.10)	2.4

Description	Directive	F2022 Revenue Requirement ($ million)	F2022 Rate Increase (%)	Refer to Section
Increase fiscal 2022 miscellaneous revenue by the estimated value of Low Carbon Fuel Credits planned to be transferred to third parties, with offsetting decrease to planned Trade Income	26	0.0	0.00	2.5
Reduce External OATT Revenue[2]		0.1	0.00	
Impact Subtotal		**(8.1)**	**(0.16)**	
Revised revenue requirement and rate increase		**5,203.6**	**1.00**	

As shown in Table 2-1 above, the difference between the interim rate increase of 1.16 per cent in fiscal 2022 and BC Hydro's calculation of a 1.00 per cent rate increase in fiscal 2022 is primarily due to the impact of deferring costs related to electric vehicle charging stations, which is explained further in sections 2.3 and 2.4 below.

Customers have been paying rates that reflect the interim rate increase of 1.16 per cent since April 1, 2021. BC Hydro plans to start charging customers the new rate, reflecting the final rate increase of 1.00 per cent, on September 1, 2021 and will provide customers with a one-time on-bill credit for the amount they overpaid from April 1, 2021 to August 31, 2021. BC Hydro expects to begin issuing this one-time on-bill credit on customers' bills later in September 2021. In order for bill credits to be issued on this timeline, BC Hydro requires the BCUC's confirmation of the revised rate increases by no later than August 13, 2021. Further information on BC Hydro's approach to bill credits is provided in section 2.6 below.

2 As a result of the adjustments ordered by the BCUC, the forecast Transmission Revenue Requirement (**TRR**) for fiscal 2022 is reduced by $8.2 million. The main driver of the reduction is additional BC Hydro revenue from Low Carbon Fuel Credits (Directive No. 26), a portion of which is allocated to the benefit of transmission customers. As a result of the reduced TRR, the forecast external OATT revenue was lowered by $0.1 million (or 0.0 per cent impact on the fiscal 2022 rate increase).

2.2 Directive 22 – Amended Interconnection Revenue

Directive 22 directed BC Hydro to amend its forecast for interconnection revenue in fiscal 2022 to $4.6 million, the same figure as BC Hydro's most recent forecast for fiscal 2021, and to make any corresponding adjustments to forecast costs required to generate this level of interconnection revenue.

This adjustment is reflected in the revised financial schedules provided in Appendix A and is shown in Table 2-2 below.

Table 2-2 Impact of Amended Interconnection Revenue

$ million	Schedule Reference	Fiscal 2022 Decision
Miscellaneous Revenue		
Increase Transmission - Interconnections	15.0, L7	2.3
Operating Costs		
Increase Interconnections and Shared Assets	5.1, L5	1.8
Reduce F22 revenue requirement		**(0.5)**

BC Hydro increased its forecast interconnection revenue from $2.3 million to $4.6 million and made corresponding adjustments to its forecast costs required to generate this level of revenue in the amount of $1.8 million. The total impact on the revenue requirements in the Test Period is ($0.5) million. This results in a (0.01) per cent decrease to fiscal 2022 rates.

2.3 Directive 24 – EV Charging Stations Cost Recovery

Directive 24 directed BC Hydro to remove all fiscal 2022 costs related to its electric vehicle charging stations that meet the definition of a prescribed undertaking under the *Greenhouse Gas Reduction (Clean Energy) Regulation* from the Test Period revenue requirements and to defer these costs to the Electric Vehicle Costs Regulatory Account. In addition, Directive 24 directed BC Hydro to suspend the recovery of fiscal 2020 and fiscal 2021 costs previously deferred to the Electric

Vehicle Costs Regulatory Account, which had been included in the Test Period revenue requirements.

In accordance with this Directive, BC Hydro has removed operating costs, amortization and cost of energy related to electric vehicle charging stations, as well as the recovery of the previously deferred costs, from the Test Period revenue requirements and deferred them to the Electric Vehicle Costs Regulatory Account, as directed. The total impact on the revenue requirements in the Test Period is ($7.7) million. This results in a 0.15 per cent decrease to fiscal 2022 rates (0.05 per cent due to the deferral of fiscal 2022 costs and 0.10 per cent due to the suspension of recovery of the fiscal 2020 and fiscal 2021 costs). The fiscal 2022 ending balance of the Electric Vehicle Costs Regulatory Account is $7.7 million, as shown in Table 2-3 below.

Table 2-3 Electric Vehicle Costs Regulatory Account Balance

$ million	Schedule Reference	F2022 Decision
Beginning of Year	2.2, L185	4.8
Adjustment to Opening Balance	2.2, L186	0.0
Additions - Operating Costs	2.2, L187	1.8
Additions - Cost of Energy	2.2, L188	0.4
Additions - Depreciation	2.2, L189	0.5
Interest	2.2, L190	0.2
Recovery	2.2, L191	0.0
End of Year	2.2, L192	**7.7**

Table 2-6 below shows the schedule lines in Appendix A that are primarily impacted by these Directives.

Table 2-4 Summary of Impact of Removal of Electric Vehicle Charging Stations Costs on Revenue Requirements

$ million	**Schedule Reference**	**F2022 Decision**
Operating Costs		
Reduce Line Asset Planning (and increase deferral)	5.1, L4	(1.0)
Reduce Customer Service (and increase deferral)	5.6, L2	(0.8)
Cost of Energy		
Increase deferral of EV Cost of Energy	4.0, L61	(0.4)
Amortization		
Increase deferral of EV Depreciation - New Assets	7.0, L20	(0.3)
Increase deferral of EV Depreciation - Existing Assets	7.0, L21	(0.2)
Subtotal – Deferrals of EV Costs in F22		(2.7)
EV Costs Regulatory Account		
Reduce recovery of EV Costs Reg. Acct. balance	5.0, L35	(4.9)
Increase regulatory account interest	2.2, L190	(0.1)
Subtotal – No Recovery of Reg. Acct. in F22		(5.0)
Reduce F22 revenue requirement		**(7.7)**

The $2.7 million subtotal shown in Table 2-4 above for fiscal 2022 electric vehicle costs matches the amount provided in BC Hydro's response to BCUC IR 1.1.3 in Exhibit B-4, during the Fiscal 2022 Revenue Requirements Application proceeding.

The $4.9 million shown in the Table 2-4 above for the planned recovery of the Electric Vehicle Costs Regulatory account balance in fiscal 2022 matches the amount shown in Appendix A, Schedule 2.2, line 192, which was based on the fiscal 2021 forecast ending balance in the account.

2.4 Directive 25 – EV Charging Stations Depreciation Rate

Directive 25 denied the depreciation rates for BC Hydro's electric vehicle charging stations. The Panel recommended that the BC Hydro Public Electric Vehicle Fast Charging Rate Application proceeding review the depreciation rates for BC Hydro's electric vehicle charging stations.

Since the fiscal 2022 costs related to the electric vehicle charging stations were removed from BC Hydro's revenue requirements pursuant to Directive 24, this directive does not have any further impact on the revised rate increase.

2.5 Directive 26 – Low Carbon Fuel Credits

Directive 26 directed BC Hydro to increase its fiscal 2022 forecast revenue by the estimated value of the low carbon fuel credits that it plans to transfer to other parties, if any, during fiscal 2022. It also directed BC Hydro to record forecast revenue, in all future revenue requirement applications, based on an estimate of the value of the low carbon fuel credits that it plans to transfer to other parties.

BC Hydro has estimated a value for the forecast revenue related to low carbon fuel credits to comply with Directive 26. This value was calculated based on a historic five-year average, which is the same approach used to calculate Trade Income for rate-making purposes. The low carbon fuel credit market is relatively new, and the policy framework continues to be developed. As a result, the volume of credits that BC Hydro will actually receive in a given fiscal year and the price that BC Hydro receives for these credits, is highly uncertain. For example, in calendar 2020 the average price per low carbon fuel credit was $250.44; however, the price per credit ranged from a low of $32.50 per credit to a high of $385.20 per credit in that year.[3] A five-year average calculation accounts for this uncertainty.

Under this approach, BC Hydro calculated a dollar amount for each fiscal year as:

- The number of credits transferred by BC Hydro to Powerex in each fiscal year; multiplied by

[3] https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/rlcf-017.pdf

- The observed market prices for the corresponding calendar year as reported by the Ministry of Energy, Mines and Low Carbon Innovation.[4,5]

The above formula was used to calculate a dollar amount for each of fiscal years 2016, 2017, 2018, 2019 and 2020 (the same fiscal years used to calculate planned Trade Income in fiscal 2022). The five-year average was then calculated as the average of those amounts, which is $31.4 million for fiscal 2022. BC Hydro has increased fiscal 2022 miscellaneous revenues by that amount.

The derivation of the annual and five-year average amounts is shown in Table 2-5 below.

Table 2-5 Value of Low Carbon Fuel Credits Calculation of Five-Year Average Fiscal 2016 to Fiscal 2020

		F2016	F2017	F2018	F2019	F2020	5 Year Average (F2016 to F2020)
A	Number of Low Carbon Fuel Credits transferred to Powerex	217,740	145,831	144,160	154,895	153,535	
B	Average Price per Credit ($)	$ 169.95	$ 170.93	$ 164.30	$ 193.44	$ 269.33	
C=A*B	Value of Low Carbon Fuel Credits ($ million)	**$ 37.0**	**$ 24.9**	**$ 23.7**	**$ 30.0**	**$ 41.4**	**$ 31.4**

As discussed further in section 3 below, because this methodology uses the observed market prices for the corresponding year, as reported by the Ministry of Energy, Mines and Low Carbon Innovation, as an input, it overstates the stand-alone value of the low carbon fuel credits to BC Hydro. BC Hydro and Powerex are currently in the early stages of negotiating a new transfer pricing agreement for low carbon fuel credits with a transfer price that reflects the stand-alone value of the low carbon fuel credits to BC Hydro.

[4] https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/rlcf-017.pdf

[5] The results reported by the Ministry of Energy, Mines and Low Carbon Innovation are in calendar years. BC Hydro has mapped calendar year 2019 to fiscal 2020, since nine of the 12 months in calendar year 2019 are in fiscal 2020. Likewise, calendar year 2018 was mapped to fiscal 2019, and so on.

The uncertainty around the low carbon fuel credits market and policy framework, along with the fact that BC Hydro and Powerex are currently negotiating a transfer pricing agreement for BC Hydro's low carbon fuel credits, means that actual revenues from low carbon fuel credits are likely to vary from forecast revenues, in fiscal 2022 and in prospective years.

Accordingly, in section 3 below, BC Hydro is seeking approval to establish the Low Carbon Fuel Credits Variance Regulatory Account to capture, on an ongoing basis, the difference between forecast and actual miscellaneous revenue from low carbon fuel credits so that the actual value of low carbon fuel credits flows back to BC Hydro's ratepayers.

In addition to increasing fiscal 2022 miscellaneous revenue by $31.4 million, BC Hydro has made an equivalent reduction to planned fiscal 2022 Trade Income. Since Powerex has been receiving these credits at zero cost and the sales of these credits have been reflected in Powerex's actual net income, which is used to calculate the rolling five-year average of Trade Income, any credit revenue included in BC Hydro's revenue forecast must be offset by an equivalent reduction in planned Trade Income, to prevent double-counting.[6]

Table 2-6 below shows the schedule lines in Appendix A that are impacted by this Directive.

6 Section 4(4) of Direction No. 8 requires the BCUC to use BC Hydro's forecast of trade income for rate-making purposes.

Table 2-6 Summary of Impact of Increase in Forecast Revenue by Estimated Value of Low Carbon Fuel Credits on Revenue Requirements

$ million	Schedule Reference	F2022 Decision
Miscellaneous Revenue		
Increase Low Carbon Fuel Credits Revenue	15.0, L29	(31.4)
Powerex Trade Income		
Reduce Powerex Trade Income	1.0, L18	31.4
Reduce F22 revenue requirement		**0.0**

2.6 Treatment of Closed Customer Accounts When Crediting Bills

The recalculation of the revenue requirements results in a smaller bill increase in fiscal 2022 compared to the interim rates that were approved and have been in effect since April 1, 2021.

As explained in section 2.1 above, BC Hydro plans to start charging customers the new rate, reflecting the final rate increase of 1.00 per cent, on September 1, 2021 and will provide customers with a one-time on-bill credit for the amount they overpaid from April 1, 2020 to August 31, 2021. BC Hydro expects to begin issuing this one-time credit on customers' bills later in September 2021.

The approach to issuing this one-time bill credit must consider customers that terminated their BC Hydro service(s) between April 1, 2021 and August 31, 2021 and no longer have any active accounts to which the credit(s) may be applied. In many instances, providing credits to these customers will result in BC Hydro incurring incremental costs greater than the amount of the bill credit because it would be necessary to attempt to locate the former customer and issue them a refund cheque. The estimated incremental cost of sending a refund cheque is $20 per customer, which includes postage and bank fees, and additional labour costs to investigate forwarding addresses and cancel refund cheques that Canada Post cannot deliver and are returned to BC Hydro. In comparison, given the small adjustment to fiscal 2022 rates, most residential customers will receive a credit of less than $1.

For this reason, BC Hydro proposes a practical approach to providing refunds to customers with non-active accounts that is consistent with the approach previously accepted by the BCUC for the application of credits resulting from the further decrease to BC Hydro’s interim fiscal 2021 rates, following the BCUC’s Decision on BC Hydro’s Fiscal 2020 to Fiscal 2021 Revenue Requirements Application. This approach is as follows:

- If a former customer is due a credit greater than $10, BC Hydro will attempt to identify the forwarding address of the former customer and mail a refund cheque to them. If a forwarding address cannot be identified, the credit will be applied to their closed account; and
- If a former customer is due a credit less than $10, BC Hydro will apply the credit to their closed account.

When a credit has been applied to a former customer’s closed account:

- The credit amount would be transferred to a new account should the former customer apply for service again; or
- Upon request from the former customer, the credit balance would be issued to them as a refund cheque or transferred to the account of another active customer, as designated by the former customer.

3 Application to Establish the Low Carbon Fuel Credits Variance Regulatory Account

BC Hydro is seeking BCUC approval for the establishment of the Low Carbon Fuel Credits Variance Regulatory Account to capture the difference between planned and actual miscellaneous revenues from low carbon fuel credits in a given year so that the actual value of low carbon fuel credits flows back to BC Hydro's ratepayers.

3.1 Background

In Undertaking No. 24, BC Hydro provided the following background information with regard to low carbon fuel credits.[7]

Under the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act* and the *Renewable and Low Carbon Fuel Requirements Regulation* (collectively, the **Low Carbon Fuel Standard** or **LCFS**), suppliers of low carbon fuels, such as BC Hydro, are the entities that are eligible to receive low carbon fuel credits.

The basic elements of the LCFS are as follows:

- The LCFS sets carbon intensity targets that decline each year;
- Fuel suppliers generate credits for supplying fuels with a carbon intensity below the targets and receive debits for supplying fuels with a carbon intensity above the targets;
- The debits and credits are proportional to the emissions a fuel generates over its full life cycle;
- Credits can be traded between fuel suppliers or banked for future use; and

[7] Refer to Undertaking No. 24 in Exhibit B-9.

- At the end of each compliance period, suppliers must have a balance of zero or more credits to avoid non-compliance penalties.

Recognizing that the LCFS awards low carbon fuel credits to suppliers of low carbon fuels rather than to end users, BC Hydro's approach has been to use the revenue from the credits to reduce the overall revenue requirement for the benefit of all ratepayers. This approach recognizes that investments in clean energy infrastructure, which have been funded by all ratepayers, have resulted in low carbon electricity, which is the primary reason that BC Hydro is able to acquire credits under the LCFS.

In BC Hydro's response to BCOAPO IR 1.67.1 in Exhibit B-5, BC Hydro stated that it received 137 low carbon fuel credits related to the ownership/operation of its electric vehicle charging stations for the 2018 calendar year.

In the March 5, 2021 Review Session on BC Hydro's Fiscal 2022 Revenue Requirements Application, BC Hydro explained that it also receives low carbon fuel credits related to the supply of electricity, as a low carbon fuel, for other means of transportation, such as SkyTrain.[8] This accounts for the vast majority of the low carbon fuel credits received by BC Hydro. As shown in Table 2-5 above, BC Hydro transferred 153,535 low carbon fuel credits to Powerex in fiscal 2020.

BC Hydro transfers its low carbon fuel credits to Powerex in accordance with section 8 of the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act* and section 11.11 of the *Renewable and the Low Carbon Fuel Requirements Regulation*. The transfer is currently made at zero cost, pursuant to an agreement between the parties, and all revenue earned by Powerex from the

[8] Transcript Volume 2, page 322, Fiscal 2022 Revenue Requirements Application, Review Session, March 5, 2021.

sale of credits flows back to BC Hydro ratepayers via Trade Income and the Trade Income Deferral Account.

The parties initially decided to transfer these credits to Powerex at zero cost. At the time, it was challenging to develop any framework that could reasonably reflect the stand-alone value of these credits to BC Hydro because:

- The market for low carbon fuel credits was relatively new, with a limited number of transactions, participants and public information;
- Legislation was evolving and uncertain, impacting the number of credits available to participants; and
- There was, and continues to be, ongoing uncertainty around the timing and volume of transfers of fuel credits from government to market participants.

In its Decision, the BCUC stated:

> "However, since the cost to generate these credits are included in BC Hydro's cost of service calculation, to arrive at an accurate net cost of service, it is necessary to include the value of these credits as revenue. Having the value of the credits embedded in Powerex's net income does not provide an accurate net cost of the BC Hydro activity that generated the credits. Further, including the value of the credits in Powerex's net income does not ensure that their value flows back to BC Hydro's ratepayers. For example, Powerex losses on other activities could, potentially, reduce Powerex's net income to zero or below, in which case none of the value of the credits would flow back to BC Hydro's ratepayers via Trade Income and the Trade Income Deferral Account.
>
> The Panel acknowledges that it cannot compel Powerex to provide the monetized amount of the credits that Powerex sells after it has received them at no cost from BC Hydro. The Panel also recognizes that the amount received by Powerex would not be the same as the amount that BC Hydro would have received had it sold the credits directly. However, BC Hydro can provide the BCUC with the quantity of credits that it has transferred or

plans to transfer to Powerex or other parties and a value can be estimated based on the market value of the credits."

3.2 Implementation of Directive 26

Directive 26 directs BC Hydro to increase its fiscal 2022 forecast revenue by the estimated value of the low carbon fuel credits that it plans to transfer to other parties, if any, during fiscal 2022. It also directs BC Hydro to record in all future revenue requirement applications, the forecast revenue based on an estimate of the value of the low carbon fuel credits that it plans to transfer to other parties.

BC Hydro and Powerex have been engaged in the process of negotiating a transfer pricing agreement that would recognize the stand-alone value of BC Hydro's low carbon fuel credits. BC Hydro and Powerex expect to finalize this transfer pricing agreement by the end of fiscal 2022.

As explained in section 2.5 above, while a new transfer pricing agreement is being negotiated, BC Hydro has estimated a value for low carbon fuel credits to comply with Directive 26. This value is $31.4 million, and BC Hydro has increased fiscal 2022 miscellaneous revenue by that amount.

The methodology used to estimate a value for low carbon fuel credits overstates the stand-alone value of the low carbon fuel credits to BC Hydro because it uses the observed market prices for the corresponding year, as reported by the Ministry of Energy, Mines and Low Carbon Innovation, which includes transactions by Powerex. As the BCUC stated in its Decision "The Panel also recognizes that the amount received by Powerex would not be the same as the amount that BC Hydro would have received had it sold the credits directly."[9] An appropriate transfer price, which reflects the stand-alone value of the low carbon fuel credits to BC Hydro, will result in a different realized value.

[9] Refer to page 105 of the Decision.

3.3 Low Carbon Fuel Credits Variance Regulatory Account

BC Hydro is applying to establish the Low Carbon Fuel Credits Variance Regulatory Account to capture, on an ongoing basis, the difference between forecast and actual miscellaneous revenue from low carbon fuel credits, and to apply interest on the balance of the account based on BC Hydro's current weighted average cost of debt.

This new regulatory account would be classified as a Cost of Energy Variance Account, which means that the balance of the account would be amortized into rates through the Deferral Account Rate Rider (**DARR**).

BC Hydro submits that this new regulatory account is necessary so that the actual value of low carbon fuel credits flows back to BC Hydro's ratepayers.

As discussed above, BC Hydro and Powerex are engaged in developing a transfer pricing agreement for BC Hydro's low carbon fuel credits, which will allow BC Hydro's revenue forecast to reflect the stand-alone value of the credits transferred to Powerex and deduct this value from Powerex's net income. As the BCUC stated in its Decision "The Panel also recognizes that the amount received by Powerex would not be the same as the amount that BC Hydro would have received had it sold the credits directly."[10]

In addition, even when it is in place, this transfer pricing agreement will not resolve the inherent uncertainty in the value associated with these credits going forward. Any forecast revenue from these credits will depend on the number of credits awarded in any given year as well as the price at which the credits are transferred to Powerex, both of which will be unknown at the time of future revenue requirements applications and which could vary depending on the terms of the transfer pricing agreement. Consequently, actual revenues from low carbon fuel credits (i.e., those

[10] Refer to page 105 of the Decision.

received from Powerex through a transfer price agreement) are likely to vary from forecast revenues in fiscal 2022 and prospective years.

Variances between planned and actual Powerex Trade Income are already captured in the Trade Income Deferral Account, which is also a Cost of Energy Variance Account, with the balance amortized into rates through the DARR. However, variances to the $31.4 million planned as miscellaneous revenue as a result of Directive 26 are not eligible for deferral treatment. This would mean that any variances would be to the account of the shareholder. If this were to occur, ratepayers would not be receiving the actual value of the credits (whether higher or lower than plan). Accordingly, BC Hydro submits that a regulatory account is required so that the actual value of low carbon fuel credits flows back to BC Hydro's ratepayers.

BC Hydro Fiscal 2022
Revenue Requirements Application

Compliance with
BCUC Decision and Order G-187-21

Appendix A

Financial Schedules

Revenue Requirements Model

Note 1: RRA (Revenue Requirement Application); TRR (Transmission Revenue Requirement)

BC Hydro
F22 RRA Compliance

Schedule 1.0
Page 2

Revenue Requirements Summary
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
Line	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	**Cost of Energy**	3.0 L1	1,505.5	1,538.7	1,518.7	1,867.9	1,810.9	(57.0)	1,666.5	1,583.7	(82.8)	1,670.1
2	**Operating Costs**	3.0 L20	1,101.5	1,076.4	1,165.1	1,136.1	1,115.2	(20.9)	1,135.4	1,148.4	13.0	1,228.5
3	**Provisions & Other**	3.0 L26	63.6	152.3	111.9	116.4	176.8	60.4	95.4	197.9	102.5	101.4
4	**Taxes**	3.0 L32	223.1	231.1	242.7	249.8	249.7	(0.1)	262.2	254.8	(7.4)	263.8
5	**Amortization**	3.0 L35	777.9	807.6	871.3	977.8	977.7	(0.0)	998.0	996.6	(1.3)	1,023.7
6	**Finance Charges**	3.0 L41	579.2	805.9	1,192.2	874.9	1,656.8	781.8	743.3	951.5	208.2	555.6
7	**Return on Equity**	3.0 L48	683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
8	**Miscellaneous Revenue**	3.0 L52	(143.1)	(143.7)	(224.4)	(240.6)	(247.3)	(6.7)	(247.0)	(243.7)	3.3	(289.0)
9	**Inter-Segment Revenue**	3.0 L61	(56.9)	(66.4)	(62.5)	(64.9)	(72.0)	(7.1)	(71.9)	(97.4)	(25.5)	(83.5)
	Deferral Accounts											
10	Deferral Account Additions	2.1 L40	63.3	203.7	586.0	3.1	52.2	49.1	3.5	(30.8)	(34.3)	15.5
11	Interest on Deferral Accounts	2.1 L41	(41.1)	(26.5)	8.2	15.4	15.9	0.5	4.0	4.8	0.8	0.7
12	Deferral Account Recoveries	2.1 L42	223.7	233.2	240.6	(392.5)	(403.9)	(11.4)	(238.3)	(238.3)	0.0	0.0
13	Total		245.8	410.4	834.7	(373.9)	(335.7)	38.2	(230.8)	(264.4)	(33.5)	16.2
	Other Regulatory Accounts											
14	Regulatory Account Additions	2.2 L225	(46.8)	(237.7)	(636.4)	(279.2)	(984.2)	(705.0)	(144.7)	(382.7)	(238.0)	(114.7)
15	Interest on Regulatory Accounts	2.2 L226	(34.2)	(35.2)	(35.7)	(33.1)	(32.6)	0.5	(30.0)	(27.2)	2.8	(25.1)
16	Regulatory Account Recoveries	2.2 L227	(57.0)	(188.4)	956.9	381.4	287.7	(93.7)	379.2	272.6	(106.6)	335.7
17	Total		(138.0)	(461.2)	284.8	69.1	(729.1)	(798.3)	204.4	(137.3)	(341.7)	195.8
	Subsidiary Net Income											
18	Powerex Trade Income		(130.2)	(136.6)	(435.7)	(176.3)	(189.2)	(13.0)	(176.3)	(176.2)	0.0	(158.7)
19	Powertech Net Income		(2.1)	(3.1)	(3.5)	(3.4)	(3.4)	0.0	(3.7)	0.0	3.7	(2.0)
20	Total		(132.4)	(139.6)	(439.1)	(179.7)	(192.7)	(13.0)	(179.9)	(176.2)	3.7	(160.7)
21	**Less Other Utilities Revenue**	14.0 L19	(13.0)	(11.9)	(29.6)	(36.1)	(29.7)	6.4	(35.9)	(30.2)	5.7	(30.2)
22	**Less Liquefied Natural Gas Revenue**	14.0 L20	(0.4)	(1.3)	(1.8)	(0.5)	(1.3)	(0.7)	0.0	0.0	0.0	0.0
23	**Less Deferral Account Rate Rider**	14.0 L23	(223.7)	(233.2)	(240.6)	0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)	0.0
24	**Total Rate Revenue Requirement**		4,472.6	4,649.1	4,795.2	5,108.1	5,084.0	(24.2)	5,051.6	4,874.3	(177.2)	5,203.6

BC Hydro **Schedule 1.0**
F22 RRA Compliance **Page 3**

Revenue Requirements Summary
($ million)

			F2017	F2018	F2019	F2020			F2021			F2022
		Reference	Actual	Actual	Actual	Decision	Actual	Diff	Decision	Forecast	Diff	Decision
Line	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Rate Revenue at Current Rates											
25	Total Domestic Revenue	14.0 L24	4,709.7	4,895.5	5,067.2	5,144.8	5,115.1	(29.6)	5,087.4	4,904.6	(182.9)	5,182.4
26	Less Other Utilities	Line 21	(13.0)	(11.9)	(29.6)	(36.1)	(29.7)	6.4	(35.9)	(30.2)	5.7	(30.2)
27	Less Liquefied Natural Gas Revenue	Line 22	(0.4)	(1.3)	(1.8)	(0.5)	(1.3)	(0.7)	0.0	0.0	0.0	0.0
28	Less Deferral Account Rate Rider	Line 23	(223.7)	(233.2)	(240.6)	0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)	0.0
29	Revenue Subject to Rate Increase		4,472.6	4,649.1	4,795.2	5,108.1	5,084.0	(24.2)	5,051.6	4,874.3	(177.2)	5,152.2
30	**Revenue Shortfall**	L24 - L29	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	51.5
31	**Rate Increases**		4.00%	3.50%	3.00%	6.85%	6.85%	-	(1.62%)	(1.62%)	-	1.00%
32	**Deferral Account Rate Rider**		5.00%	5.00%	5.00%	-	-	-	-	-	-	-
33	**Net Bill Impact**		4.00%	3.50%	3.00%	1.76%	1.76%	-	(1.62%)	(1.62%)	-	1.00%
34	**Total Rate Revenue Requirement**	Line 24	4,472.6	4,649.1	4,795.2	5,108.1	5,084.0	(24.2)	5,051.6	4,874.3	(177.2)	5,203.6
35	**Rate Smoothing Regulatory Account transfers**	2.2 L131	201.2	326.2	(814.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	**Revenue Requirement before transfers to Rate Smoothing Reg. Acct.**		4,673.8	4,975.3	3,980.3	5,108.1	5,084.0	(24.2)	5,051.6	4,874.3	(177.2)	5,203.6

BC Hydro
F22 RRA Compliance

Schedule 2.1
Page 4

Deferral Accounts
($ million)

Line	Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Heritage Deferral Account											
1	Beginning of Year		(23.9)	(53.1)	(103.7)	(485.1)	(485.1)	0.0	(225.6)	(300.1)	(74.5)	114.4
2	Adjustment to Opening Balance		(0.0)	0.0	(318.9)	0.0	0.0	0.0	0.0	59.6	59.6	0.0
3	Additions	Line 46	(31.0)	(60.4)	(95.2)	0.0	(82.4)	(82.4)	0.0	127.5	127.5	0.0
4	Interest		(2.8)	(4.0)	(18.5)	(13.1)	(13.2)	(0.1)	(4.0)	(2.1)	1.9	3.5
5	Recovery		4.7	13.8	51.2	272.6	280.6	7.9	229.5	229.5	0.0	0.0
6	End of Year		(53.1)	(103.7)	(485.1)	(225.6)	(300.1)	(74.5)	0.0	114.4	114.4	118.0
	Non-Heritage Deferral Account											
7	Beginning of Year		916.8	755.8	463.3	76.1	76.1	0.0	(111.3)	204.7	316.0	(264.9)
8	Adjustment to Opening Balance		(0.1)	0.0	(0.6)	64.8	64.8	0.0	0.0	(354.4)	(354.4)	0.0
9	Transfer to Load Variance					(287.3)	0.0	287.3	0.0	0.0	0.0	0.0
10	Additions	Line 47	(17.2)	(122.0)	(118.4)	0.0	100.1	100.1	0.0	(221.7)	(221.7)	0.0
11	Additions - Waneta 2/3	15.0 L36			(51.9)	(3.1)	(1.3)	1.8	(3.5)	(3.5)	(0.0)	(15.5)
12	Interest		35.7	26.0	12.7	(4.8)	5.9	10.7	(2.1)	(6.9)	(4.8)	(8.4)
13	Recovery		(179.4)	(196.5)	(229.1)	43.0	(40.9)	(83.9)	116.8	116.8	0.0	0.0
14	End of Year		755.8	463.3	76.1	(111.3)	204.7	316.0	(0.0)	(264.9)	(264.9)	(288.8)
	Trade Income Deferral Account											
15	Beginning of Year		250.0	194.2	126.8	(258.8)	(258.8)	0.0	(107.9)	(173.7)	(65.8)	(14.3)
16	Adjustment to Opening Balance		(0.0)	0.0	0.0	(1.9)	(1.9)	0.0	0.0	51.9	51.9	0.0
17	Additions	Line 48	(15.1)	(21.4)	(320.5)	0.0	(68.7)	(68.7)	0.0	(0.0)	(0.0)	0.0
18	Interest		8.2	4.5	(2.4)	(6.8)	(8.6)	(1.8)	(1.9)	(2.3)	(0.4)	(0.4)
19	Recovery		(48.9)	(50.5)	(62.7)	159.5	164.2	4.7	109.8	109.8	0.0	0.0
20	End of Year		194.2	126.8	(258.8)	(107.9)	(173.7)	(65.8)	(0.0)	(14.3)	(14.3)	(14.7)
	Load Variance											
21	Beginning of Year					0.0	0.0	0.0	214.0	0.0	(214.0)	158.9
22	Adjustment to Opening Balance	Line 9				287.3	0.0	(287.3)	0.0	234.8	234.8	0.0
23	Additions	Line 49				0.0	0.0	0.0	0.0	135.5	135.5	0.0
24	Interest					9.3	0.0	(9.3)	3.9	6.5	2.6	4.9
25	Recovery					(82.7)	0.0	82.7	(217.8)	(217.8)	0.0	0.0
26	End of Year					214.0	0.0	(214.0)	0.0	158.9	158.9	163.8
	Biomass Energy Program Variance											
27	Beginning of Year					0.0	0.0	0.0	0.0	0.0	0.0	(8.1)
28	Adjustment to Opening Balance					0.0	0.0	0.0	0.0	(1.1)	(1.1)	0.0
29	Additions - Cost of Energy	Line 50				0.0	0.0	0.0	0.0	(5.1)	(5.1)	0.0
30	Additions - Revenue	Line 51				0.0	0.0	0.0	0.0	(1.7)	(1.7)	0.0
31	Interest					0.0	0.0	0.0	0.0	(0.2)	(0.2)	(0.2)
32	Recovery					0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	End of Year					0.0	0.0	0.0	0.0	(8.1)	(8.1)	(8.3)

BC Hydro **Schedule 2.1**
F22 RRA Compliance **Page 5**

Deferral Accounts
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
Column			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	End of Year Balances											
34	Heritage	Line 6	(53.1)	(103.7)	(485.1)	(225.6)	(300.1)	(74.5)	0.0	114.4	114.4	118.0
35	Non-Heritage	Line 14	755.8	463.3	76.1	(111.3)	204.7	316.0	(0.0)	(264.9)	(264.9)	(288.8)
36	Trade Income	Line 20	194.2	126.8	(258.8)	(107.9)	(173.7)	(65.8)	(0.0)	(14.3)	(14.3)	(14.7)
37	Load Variance	Line 26	0.0	0.0	0.0	214.0	0.0	(214.0)	0.0	158.9	158.9	163.8
38	Biomass Energy Program Cost	Line 33	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(8.1)	(8.1)	(8.3)
39	Total		896.9	486.5	(667.7)	(230.8)	(269.1)	(38.2)	0.0	(13.9)	(13.9)	(30.1)
	Summary											
40	Deferral Account Additions		(63.3)	(203.7)	(586.0)	(3.1)	(52.2)	(49.1)	(3.5)	30.8	34.3	(15.5)
41	Interest on Deferral Accounts		41.1	26.5	(8.2)	(15.4)	(15.9)	(0.5)	(4.0)	(4.8)	(0.8)	(0.7)
42	Deferral Account Recoveries		(223.7)	(233.2)	(240.6)	392.5	403.9	11.4	238.3	238.3	0.0	0.0
43	Adjustment to Opening Balance	L2+L8+L9+L16+L22+L28	(0.2)	0.0	(319.5)	62.9	62.9	0.0	0.0	(9.2)	(9.2)	0.0
44	Net Transfers		(246.0)	(410.4)	(1,154.2)	436.9	398.6	(38.2)	230.8	255.2	24.3	(16.2)
45	**Interest Rate**	8.0 L52	3.97%	3.96%	3.99%	3.81%	3.74%	(0.07%)	3.73%	3.37%	(0.36%)	3.09%
	Summary of Items Subject to Deferral											
46	Cost of Heritage Energy	4.0 L80	274.3	225.1	221.9	513.3	499.3	(14.0)	219.0	345.6	126.5	392.7
47	Cost of Non-Heritage Energy	4.0 L98	1,254.7	1,287.3	1,364.5	1,321.7	1,426.1	104.4	1,370.7	1,398.2	27.6	1,185.8
48	Trade Income	1.0 L18	(130.2)	(136.6)	(435.7)	(176.3)	(189.2)	(13.0)	(176.3)	(176.2)	0.0	(158.7)
49	Load Variance	14.0 L40				(5,099.7)	(5,079.5)	20.3	(5,036.5)	(4,901.1)	135.5	(5,187.7)
50	Biomass Energy Program Variance - COE	4.0 L99				35.8	31.6	(4.3)	80.7	75.5	(5.1)	102.4
51	Biomass Energy Program Variance - Revenue	14.0 L41				(9.0)	(5.8)	3.2	(15.2)	(16.9)	(1.7)	15.9

BC Hydro
F22 RRA Compliance

Other Regulatory Accounts
($ million)

Line		Reference	F2017	F2018	F2019	F2020			F2021			F2022
			Actual	Actual	Actual	Decision	Actual	Diff	Decision	Forecast	Diff	Decision
Line	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Demand-Side Management											
1	Beginning of Year		907.2	915.6	902.5	914.5	914.5	0.0	920.3	906.6	(13.7)	890.1
2	Adjustment to Opening Balance		0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Additions	5.0 L52 - Line 4	97.4	82.3	104.2	90.8	78.5	(12.4)	89.1	82.4	(6.6)	82.2
4	Additions - Low Carbon Electrification		0.0	0.2	7.1	18.3	16.9	(1.4)	9.7	7.6		15.5
5	Amortization on Existing		(89.1)	(95.6)	(99.3)	(103.3)	(103.3)	0.0	(107.4)	(106.5)	0.9	(108.0)
6	Amortization on Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	End of Year		915.6	902.5	914.5	920.3	906.6	(13.7)	911.7	890.1	(21.5)	879.9
	First Nations Costs											
8	Beginning of Year		132.8	123.6	104.3	85.0	85.0	0.0	71.4	69.5	(1.9)	54.0
9	Adjustment to Opening Balance		0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Additions	5.0 L53	4.0	2.0	2.3	3.2	2.5	(0.6)	2.4	2.4	(0.1)	2.1
11	Transfer from Provision	Line 19	13.8	12.6	13.7	15.0	12.8	(2.1)	13.1	13.7	0.6	14.7
12	Interest		5.4	4.8	4.0	2.9	3.1	0.2	2.3	2.0	(0.3)	1.4
13	Recovery	5.0 L24	(32.4)	(38.7)	(39.3)	(34.7)	(34.1)	0.6	(33.7)	(33.6)	0.1	(34.4)
14	End of Year		123.6	104.3	85.0	71.4	69.5	(1.9)	55.5	54.0	(1.6)	37.7
	First Nations Settlement Provisions											
15	Beginning of Year		408.6	408.6	414.2	420.3	420.3	0.0	423.0	426.0	3.0	431.5
16	Adjustment to Opening Balance		(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Additions - Operating	5.01 L35	(3.3)	0.9	2.4	0.0	0.9	0.9	0.0	1.2	1.2	0.0
18	Additions - Accretion	8.0 L4	17.2	17.2	17.5	17.6	17.6	0.0	18.0	18.0	0.0	18.3
19	Transfer to Negotiation Costs		(13.8)	(12.6)	(13.7)	(15.0)	(12.8)	2.1	(13.1)	(13.7)	(0.6)	(14.7)
20	End of Year		408.6	414.2	420.3	423.0	426.0	3.0	427.9	431.5	3.6	435.2
	Site C Project											
21	Beginning of Year		435.6	453.3	472.0	491.3	491.3	0.0	508.4	508.4	0.0	523.6
22	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Additions	5.0 L54+8.0 L22	0.0	0.3	0.3	(1.7)	(1.5)	0.1	(2.4)	(1.8)	0.6	(7.0)
24	Interest		17.7	18.4	19.0	18.7	18.6	(0.1)	18.9	17.1	(1.8)	16.1
25	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	End of Year		453.3	472.0	491.3	508.4	508.4	0.0	524.9	523.6	(1.3)	532.8
	Future Removal and Site Restoration											
27	Beginning of Year		(8.6)	2.9	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)
28	Adjustment to Opening Balance		(0.0)	(2.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Additions	5.01 L40	2.9					0.0			0.0	
30	Recovery	7.0 L31	8.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	End of Year		2.9	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)
	Foreign Exchange Gains/Losses											
32	Beginning of Year		(68.6)	(65.5)	(31.3)	11.9	11.9	0.0	9.0	16.6	7.5	13.5
33	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Additions	8.0 L2	3.4	(4.2)	4.0	(2.3)	5.3	7.5	(1.5)	(3.0)	(1.4)	(2.6)
35	Recovery	8.0 L26	(0.4)	38.3	39.2	(0.5)	(0.5)	(0.0)	0.5	(0.1)	(0.6)	0.1
36	End of Year		(65.5)	(31.3)	11.9	9.0	16.6	7.5	8.0	13.5	5.5	11.1

BC Hydro | **Schedule 2.2**
F22 RRA Compliance | **Page 7**

Other Regulatory Accounts
($ million)

Line		Reference Column	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Pre-1996 Customer Contributions											
37	Beginning of Year		92.1	91.4	88.2	83.3	83.3	0.0	78.2	78.2	0.0	73.1
38	Adjustment to Opening Balance		(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Recovery	7.0 L32	(0.7)	(3.2)	(4.9)	(5.1)	(5.1)	0.0	(5.1)	(5.1)	0.0	(5.1)
40	End of Year		91.4	88.2	83.3	78.2	78.2	0.0	73.1	73.1	0.0	67.9
	Storm Restoration Costs											
41	Beginning of Year		29.5	38.6	46.5	58.0	58.0	0.0	29.0	20.8	(8.3)	(12.7)
42	Adjustment to Opening Balance		(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	(4.0)	(4.0)	0.0
43	Additions – Storm Restoration Costs	5.0 L55 - Line 44	18.6	16.2	18.9	0.0	(7.8)	(7.8)	0.0	0.0	0.0	0.0
44	Additions - Evacuation Relief						0.0	0.0		0.0	0.0	0.0
45	Interest		1.3	2.1	2.6	1.6	1.1	(0.5)	0.5	0.1	(0.5)	(0.2)
46	Recovery	5.0 L25	(10.8)	(10.4)	(10.0)	(30.6)	(30.6)	(0.0)	(29.5)	(29.5)	0.0	12.9
47	End of Year		38.6	46.5	58.0	29.0	20.8	(8.3)	0.0	(12.7)	(12.7)	(0.0)
	Capital Project Investigation											
48	Beginning of Year		25.0	20.1	15.3	10.5	10.5	0.0	5.2	5.2	(0.0)	(0.0)
49	Adjustment to Opening Balance		0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
50	Recovery	5.0 L26	(4.8)	(4.8)	(4.8)	(5.2)	(5.2)	(0.0)	(5.2)	(5.2)	0.0	0.0
51	End of Year		20.1	15.3	10.5	5.2	5.2	(0.0)	0.0	(0.0)	(0.0)	(0.0)
	Amortization of Capital Additions											
52	Beginning of Year		(9.7)	(8.8)	(5.2)	18.4	18.4	0.0	9.2	8.9	(0.4)	(2.1)
53	Adjustment to Opening Balance		(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Additions	7.0 L19	(2.0)	0.7	20.4	0.0	(0.4)	(0.4)	0.0	(1.6)	(1.6)	0.0
55	Interest		(0.6)	(0.5)	(0.1)	0.5	0.6	0.1	0.2	0.1	(0.1)	(0.0)
56	Recovery		3.6	3.4	3.3	(9.7)	(9.7)	0.0	(9.4)	(9.4)	0.0	2.1
57	End of Year		(8.8)	(5.2)	18.4	9.2	8.9	(0.4)	(0.0)	(2.1)	(2.1)	(0.0)
	Total Finance Charges											
58	Beginning of Year		(305.5)	(215.5)	(139.4)	20.2	20.2	0.0	10.1	11.1	0.9	(74.1)
59	Adjustment to Opening Balance		(0.0)	0.0	5.0	0.0	0.0	0.0	0.0	1.6	1.6	0.0
60	Additions	8.0 L21	(12.6)	(25.1)	52.8	0.0	0.9	0.9	0.0	(76.6)	(76.6)	0.0
61	Recovery	8.0 L28+ L30	102.6	101.1	101.8	(10.1)	(10.1)	0.0	(10.1)	(10.1)	0.0	74.1
62	End of Year		(215.5)	(139.4)	20.2	10.1	11.1	0.9	(0.0)	(74.1)	(74.1)	0.0

BC Hydro
F22 RRA Compliance

Schedule 2.2
Page 8

Other Regulatory Accounts
($ million)

Line	Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Smart Metering & Infrastructure											
63	Beginning of Year		282.6	260.9	239.2	217.2	217.2	0.0	195.5	195.4	(0.1)	173.0
64	Adjustment to Opening Balance		(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
65	Additions - Deferred Operating	5.0 L56	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	Additions - DSMD Write-Off	5.01 L38	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
67	Additions - Miscellaneous Revenue	15.0 L37	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
68	Interest		11.0	10.1	9.2	7.7	7.8	0.0	6.8	6.1	(0.7)	4.9
69	Recovery	5.0 L27	(32.6)	(31.8)	(31.1)	(29.4)	(29.6)	(0.2)	(28.5)	(28.5)	0.0	(26.6)
70	End of Year		260.9	239.2	217.2	195.5	195.4	(0.1)	173.8	173.0	(0.8)	151.4
	Home Purchase Option Plan											
71	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
72	Adjustment to Opening Balance		(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
73	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
74	Recovery	5.0 L28	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
75	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Non-Current Pension Cost											
76	Beginning of Year		690.5	510.7	303.4	485.5	485.5	0.0	364.1	210.1	(154.0)	1,135.7
77	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.4	5.4	0.0
78	OCI Deferral	9.0 L8	(203.2)	(193.6)	173.1	(70.0)	(317.2)	(247.2)	0.0	865.4	865.4	0.0
79	Additions		10.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
80	Recovery - Operating	5.0 L30	(59.3)	(57.9)	(57.9)	(51.4)	(56.8)	(5.4)	(51.4)	(51.4)	0.0	(114.6)
81	Recovery - Finance Charges	8.0 L27	72.6	70.0	66.8	0.0	98.6	98.6	0.0	106.2	106.2	0.0
82	Transfer to PEB Current Pension-Addition		0.0	(27.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
83	Transfer to PEB Current Pension-Recovery		0.0	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
84	End of Year		510.7	303.4	485.5	364.1	210.1	(154.0)	312.7	1,135.7	823.0	1,021.1
	Environmental Provisions											
85	Beginning of Year		380.9	333.2	309.6	278.5	278.5	0.0	236.2	305.1	68.8	344.1
86	Adjustment to Opening Balance		(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
87	Additions - Deferred Operating	5.01 L36	(28.0)	(4.0)	(7.1)	0.0	51.2	51.2	0.0	96.0	96.0	0.0
88	Additions - Accretion	8.0 L5	3.9	4.4	5.9	5.5	4.8	(0.7)	4.8	3.8	(1.0)	3.4
89	Transfer to Rock Bay		(1.6)	(0.7)	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
90	Transfer to Remediation (Asbestos)		(7.9)	(9.0)	(11.0)	(21.7)	(8.2)	13.5	(18.8)	(16.7)	2.1	(22.4)
91	Transfer to Remediation (PCB)	5.01 L17	(14.2)	(14.3)	(18.6)	(26.1)	(21.2)	4.9	(26.0)	(44.0)	(18.0)	(39.1)
92	End of Year		333.2	309.6	278.5	236.2	305.1	68.8	196.2	344.1	147.9	286.0

BC Hydro **Schedule 2.2**
F22 RRA Compliance **Page 9**

Other Regulatory Accounts
($ million)

Line		Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
				1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Rock Bay Remediation												
93	Beginning of Year			(27.2)	(23.0)	(20.0)	(20.5)	(20.5)	0.0	(10.3)	(10.4)	(0.1)	(0.1)
94	Adjustment to Opening Balance			(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
95	Transfer from Environmental		Line 89	1.6	0.7	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
96	Interest			(1.0)	(0.9)	(0.8)	(0.6)	(0.6)	(0.1)	(0.2)	(0.2)	0.0	(0.0)
97	Recovery		5.01 L20	3.8	3.2	(0.0)	10.8	10.8	0.0	10.4	10.4	0.0	0.1
98	End of Year			(23.0)	(20.0)	(20.5)	(10.3)	(10.4)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)
	IFRS PP&E												
99	Beginning of Year			873.0	961.8	1,025.4	1,064.4	1,064.4	0.0	1,079.2	1,079.2	(0.0)	1,070.6
100	Adjustment to Opening Balance			(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
101	Additions - Deferred Operating		5.0 L57	112.0	89.6	67.2	44.8	44.8	0.0	22.4	22.4	0.0	0.0
102	Recovery		5.0 L33	(23.2)	(26.0)	(28.2)	(29.9)	(29.9)	(0.0)	(31.0)	(31.0)	0.0	(31.6)
103	End of Year			961.8	1,025.4	1,064.4	1,079.2	1,079.2	(0.0)	1,070.6	1,070.6	(0.0)	1,039.0
	IFRS Pension												
104	Beginning of Year			611.9	573.6	535.4	497.1	497.1	0.0	458.9	458.9	0.0	420.6
105	Adjustment to Opening Balance			(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
106	Recovery		5.0 L34	(38.2)	(38.2)	(38.2)	(38.2)	(38.2)	0.0	(38.2)	(38.2)	0.0	(38.2)
107	End of Year			573.6	535.4	497.1	458.9	458.9	0.0	420.6	420.6	0.0	382.4
	Arrow Water Divestiture Costs												
108	Beginning of Year			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0
109	Adjustment to Opening Balance			(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110	Transfer from Provision		Line 118	0.3	1.8	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
111	Interest			0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0
112	Recovery		5.01 L21:L22	(0.3)	(1.8)	(3.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
113	End of Year			0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0
	Arrow Water Provision												
114	Beginning of Year			4.6	4.5	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
115	Adjustment to Opening Balance			(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
116	Additions		5.01 L37	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
117	Additions - Accretion		8.0 L6	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
118	Transfer to Arrow Water Costs		5.01 L22	(0.3)	(1.8)	(3.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
119	Recovery			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
120	End of Year			4.5	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

BC Hydro
F22 RRA Compliance

Schedule 2.2
Page 10

Other Regulatory Accounts
($ million)

Line		Column / Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Remediation											
121	Beginning of Year		5.1	(15.8)	(28.6)	(30.8)	(30.8)	0.0	(15.4)	(34.3)	(18.8)	(3.3)
122	Adjustment to Opening Balance		(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0
123	Transfer from Env. Prov. (Asbestos)	Line 90	7.9	9.0	11.0	21.7	8.2	(13.5)	18.8	16.7	(2.1)	22.4
124	Transfer from Env. Prov. (PCB)	Line 91	14.2	14.3	18.6	26.1	21.2	(4.9)	26.0	44.0	18.0	39.1
125	Interest		(0.2)	(0.7)	(1.2)	(0.9)	(1.3)	(0.4)	(0.3)	(0.6)	(0.3)	(0.1)
126	Recovery	5.01 L17:L18	(42.7)	(35.4)	(30.6)	(31.6)	(31.6)	0.0	(29.2)	(29.2)	0.0	(58.1)
127	End of Year		(15.8)	(28.6)	(30.8)	(15.4)	(34.3)	(18.8)	(0.1)	(3.3)	(3.2)	(0.0)
	Rate Smoothing											
128	Beginning of Year		287.4	488.7	814.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
129	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
130	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
131	Recovery	5.01 L23	201.2	326.2	(814.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
132	End of Year		488.7	814.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Real Property Sales											
133	Beginning of Year		17.7	28.2	37.7	49.2	49.2	0.0	50.9	56.2	5.3	47.8
134	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	(10.0)	(10.0)	0.0
135	Additions	5.0 L60+5.01 L39	9.8	8.4	10.0	0.0	5.3	5.3	(0.0)	0.0	0.0	0.0
136	Interest		0.7	1.1	1.4	1.7	1.7	0.0	1.4	1.6	0.2	1.5
137	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
138	End of Year		28.2	37.7	49.2	50.9	56.2	5.3	52.3	47.8	(4.5)	49.2
	Minimum Reconnection Charge											
139	Beginning of Year		0.5	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
140	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141	Additions	15.0 L38	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
142	Interest		0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143	Recovery		(0.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
144	End of Year		0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Debt Management											
145	Beginning of Year		0.0	(187.1)	(157.8)	163.2	163.2	0.0	276.5	952.9	676.4	1,150.3
146	Adjustment to Opening Balance		(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
147	Additions	8.0 L7	(187.1)	29.3	321.0	100.9	777.3	676.4	0.0	185.0	185.0	0.0
148	Recovery	8.0 L29	0.0	0.0	0.0	12.4	12.4	0.0	12.4	12.4	0.0	(9.1)
149	End of Year		(187.1)	(157.8)	163.2	276.5	952.9	676.4	288.9	1,150.3	861.4	1,141.2
	Dismantling Cost											
150	Beginning of Year		0.0	0.0	35.4	48.3	48.3	0.0	24.1	16.0	(8.2)	(3.3)
151	Adjustment to Opening Balance		0.0	2.9	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
152	Additions	5.01 L40		31.7	11.3	0.0	(8.5)	(8.5)	0.0	5.1	5.1	0.0
153	Interest		0.0	0.7	1.6	1.4	1.6	0.3	0.4	0.2	(0.2)	(0.1)
154	Recovery	5.01 L19		0.0	0.0	(25.5)	(25.5)	0.0	(24.6)	(24.6)	0.0	3.3
155	End of Year		0.0	35.4	48.3	24.1	16.0	(8.2)	(0.0)	(3.3)	(3.3)	(0.0)

Other Regulatory Accounts
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	PEB Current Pension Costs											
156	Beginning of Year		0.0	0.0	3.3	(1.7)	(1.7)	0.0	(0.9)	(1.8)	(0.9)	(6.7)
157	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
158	OCI Deferral		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
159	Additions	5.0 L58+L59	0.0	(12.5)	0.7	0.0	(0.9)	(0.9)	0.0	(5.8)	(5.8)	0.0
160	Recovery - Operating	5.0 L31+L32	0.0	(10.0)	(5.7)	0.9	0.9	(0.0)	0.9	0.9	0.0	6.7
161	Transfer from Non-Current Pension-Addition	Line 82	0.0	27.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
162	Transfer from Non-Current Pension-Recovery	Line 83	0.0	(1.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
163	End of Year		0.0	3.3	(1.7)	(0.9)	(1.8)	(0.9)	0.0	(6.7)	(6.7)	0.0
	Customer Crisis Fund											
164	Beginning of Year		0.0	0.0	0.1	(2.6)	(2.6)	0.0	(2.9)	(5.3)	(2.4)	33.4
165	Adjustment to Opening Balance					0.0	0.0	0.0	0.0	0.0	0.0	0.0
166	Additions - CCF	5.0 L61 - Line167	0.0	0.1	(2.7)	(0.3)	(2.7)	(2.4)	(0.3)	(0.3)	0.0	0.0
167	Additions - COVID-19 Relief operating costs					0.0	0.0	0.0	0.0	1.2	1.2	0.0
168	Additions - COVID-19 Residential Grants	14.0 L37				0.0	0.0	0.0	0.0	37.3	37.3	0.0
169	Interest					0.0	0.0	0.0	(0.1)	0.5	0.6	1.0
170	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
171	End of Year		0.0	0.1	(2.6)	(2.9)	(5.3)	(2.4)	(3.3)	33.4	36.7	34.5
	Mining Customer Payment Plan											
172	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0
173	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
174	Additions	5.0 L63	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.0
175	Additions - COVID-19 SGS Waivers	14.0 L38				0.0	0.0	0.0	0.0	6.4	6.4	0.0
176	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2
177	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
178	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0	7.0	7.2
	Project Write-off Costs											
179	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.4
180	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.3	9.3	0.0
181	Additions	5.01 L41	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
182	Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.1
183	Recovery	5.01 L24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(9.3)
184	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.4	9.4	0.3
	Electric Vehicle Costs											
185	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	2.3	0.0	(2.3)	4.8
186	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.3	2.3	0.0
187	Additions - Operating Costs	5.0 L62	0.0	0.0	0.0	1.9	0.0	(1.9)	1.7	1.7	0.0	1.8
188	Additions - Cost of Energy	4.0 L61				0.2	0.0	(0.2)	0.3	0.3	0.0	0.4
189	Additions - Depreciation	7.0 L20:L21				0.2	0.0	(0.2)	0.5	0.5	0.0	0.5
190	Interest		0.0	0.0	0.0	0.0	0.0	(0.0)	0.1	0.1	(0.1)	0.2
191	Recovery	5.0 L35	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
192	End of Year		0.0	0.0	0.0	2.3	0.0	(2.3)	4.9	4.8	(0.1)	7.7

BC Hydro
F22 RRA Compliance

Schedule 2.2
Page 12

Other Regulatory Accounts
($ million)

Line		Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
				1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	End of Year Balances												
193	Demand-Side Management		Line 7	915.6	902.5	914.5	920.3	906.6	(13.7)	911.7	890.1	(21.5)	879.9
194	First Nations Costs		Line 14	123.6	104.3	85.0	71.4	69.5	(1.9)	55.5	54.0	(1.6)	37.7
195	First Nations Settlement Provisions		Line 20	408.6	414.2	420.3	423.0	426.0	3.0	427.9	431.5	3.6	435.2
196	Site C Project		Line 26	453.3	472.0	491.3	508.4	508.4	0.0	524.9	523.6	(1.3)	532.8
197	Future Removal and Site Restoration		Line 31	2.9	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	(0.0)
198	Foreign Exchange Gains/Losses		Line 36	(65.5)	(31.3)	11.9	9.0	16.6	7.5	8.0	13.5	5.5	11.1
199	Pre-1996 Customer Contributions		Line 40	91.4	88.2	83.3	78.2	78.2	0.0	73.1	73.1	0.0	67.9
200	Storm Restoration Costs		Line 47	38.6	46.5	58.0	29.0	20.8	(8.3)	0.0	(12.7)	(12.7)	(0.0)
201	Capital Project Investigation		Line 51	20.1	15.3	10.5	5.2	5.2	(0.0)	0.0	(0.0)	(0.0)	(0.0)
202	Amortization of Capital Additions		Line 57	(8.8)	(5.2)	18.4	9.2	8.9	(0.4)	(0.0)	(2.1)	(2.1)	(0.0)
203	Total Finance Charges		Line 62	(215.5)	(139.4)	20.2	10.1	11.1	0.9	(0.0)	(74.1)	(74.1)	0.0
204	Smart Metering & Infrastructure		Line 70	260.9	239.2	217.2	195.5	195.4	(0.1)	173.8	173.0	(0.8)	151.4
205	Home Purchase Option Plan		Line 75	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
206	Non-Current Pension Cost		Line 84	510.7	303.4	485.5	364.1	210.1	(154.0)	312.7	1,135.7	823.0	1,021.1
207	Environmental Provisions		Line 92	333.2	309.6	278.5	236.2	305.1	68.8	196.2	344.1	147.9	286.0
208	Rock Bay Remediation		Line 98	(23.0)	(20.0)	(20.5)	(10.3)	(10.4)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)
209	IFRS PP&E		Line 103	961.8	1,025.4	1,064.4	1,079.2	1,079.2	(0.0)	1,070.6	1,070.6	(0.0)	1,039.0
210	IFRS Pension		Line 107	573.6	535.4	497.1	458.9	458.9	0.0	420.6	420.6	0.0	382.4
211	Arrow Water Divestiture Costs		Line 113	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0
212	Arrow Water Provision		Line 120	4.5	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
213	Remediation		Line 127	(15.8)	(28.6)	(30.8)	(15.4)	(34.3)	(18.8)	(0.1)	(3.3)	(3.2)	(0.0)
214	Rate Smoothing		Line 132	488.7	814.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
215	Real Property Sales		Line 138	28.2	37.7	49.2	50.9	56.2	5.3	52.3	47.8	(4.5)	49.2
216	Minimum Reconnection Charge		Line 144	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
217	Debt Management		Line 149	(187.1)	(157.8)	163.2	276.5	952.9	676.4	288.9	1,150.3	861.4	1,141.2
218	Dismantling Cost		Line 155	0.0	35.4	48.3	24.1	16.0	(8.2)	(0.0)	(3.3)	(3.3)	(0.0)
219	PEB Current Pension Costs		Line 163	0.0	3.3	(1.7)	(0.9)	(1.8)	(0.9)	0.0	(6.7)	(6.7)	0.0
220	Customer Crisis Fund		Line 171	0.0	0.1	(2.6)	(2.9)	(5.3)	(2.4)	(3.3)	33.4	36.7	34.5
221	Mining Customer Payment Plan		Line 178	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0	7.0	7.2
222	Project Write-off Costs		Line 184	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.4	9.4	0.3
223	Electric Vehicle Costs		Line 192	0.0	0.0	0.0	2.3	0.0	(2.3)	4.9	4.8	(0.1)	7.7
224	Total			4,700.1	4,967.8	4,861.1	4,722.1	5,273.1	551.0	4,517.7	6,280.3	1,762.6	6,084.5
	Summary												
225	Regulatory Account Additions			46.8	237.7	636.4	279.2	984.2	705.0	144.7	382.7	238.0	114.7
226	Interest on Regulatory Accounts			34.2	35.2	35.7	33.1	32.6	(0.5)	30.1	27.2	(2.9)	25.1
227	Regulatory Account Recoveries			57.0	188.4	(956.9)	(381.4)	(287.7)	93.7	(379.2)	(272.6)	106.6	(335.7)
228	Adjustments to Opening Balances			(0.2)	0.1	5.0	0.1	0.1	(0.0)	0.0	4.5	4.5	0.0
229	OCI Deferral (Pension)			(203.2)	(193.6)	173.1	(70.0)	(317.2)	(247.2)	0.0	865.4	865.4	0.0
230	Regulatory Account Net Transfers			(65.4)	267.7	(106.7)	(139.0)	412.0	551.0	(204.4)	1,007.2	1,211.6	(195.8)
231	**Interest Rate**		8.0 L52	3.97%	3.96%	3.99%	3.81%	3.74%	(0.07%)	3.73%	3.37%	(0.36%)	3.09%

BC Hydro | **Schedule 3.0**
F22 RRA Compliance | **Page 13**

Reconciliation of Current and Gross Views
($ million)

Line	Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Cost of Energy											
1	Total Gross	4.0 L46	1,505.5	1,538.7	1,518.7	1,867.9	1,810.9	(57.0)	1,666.5	1,583.7	(82.8)	1,670.1
2	HDA Additions	4.0 L47	31.0	60.4	95.2	0.0	82.4	82.4	0.0	(127.5)	(127.5)	0.0
3	NHDA Additions	4.0 L48	17.2	122.0	118.4	0.0	(100.1)	(100.1)	0.0	221.7	221.7	0.0
4	Deferred Operating HDA	4.0 L49	(0.1)	0.3	(0.2)	0.0	(1.4)	(1.4)	0.0	(0.7)	(0.7)	0.0
5	Deferred Operating NHDA	4.0 L50	(8.9)	(35.6)	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Deferred Amortization NHDA	4.0 L51	(3.3)	(14.0)	0.0	0.0	0.4	0.4	0.0	(0.2)	(0.2)	0.0
7	Deferred Taxes NHDA	4.0 L52	(0.4)	(1.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Deferred Provision NHDA	4.0 L53	0.0	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	HDA Recoveries	4.0 L54	(4.7)	(13.8)	(51.2)	(272.6)	(280.6)	(7.9)	(229.5)	(229.5)	0.0	0.0
10	NHDA Recoveries	4.0 L55	179.4	196.5	229.1	(43.0)	40.9	83.9	(116.8)	(116.8)	0.0	0.0
11	Load Variance Additions - Revenue	4.0 L56				0.0	0.0	0.0	0.0	(135.5)	(135.5)	0.0
12	Biomass Energy Program Variance Additions - Cost of Er	4.0 L57				0.0	0.0	0.0	0.0	5.1	5.1	0.0
13	Biomass Energy Program Variance Additions - Revenue	4.0 L58				0.0	0.0	0.0	0.0	1.7	1.7	0.0
14	Customer Crisis Fund Additions - COVID-19 Res. Grants	4.0 L59				0.0	0.0	0.0	0.0	(37.3)	(37.3)	0.0
15	Mining Cust. Pay. Plan Additions - COVID-19 SGS Waive	4.0 L60				0.0	0.0	0.0	0.0	(6.4)	(6.4)	0.0
16	Electric Vehicle Costs Additions - Cost of Energy	4.0 L61				(0.2)	0.0	0.2	(0.3)	(0.3)	0.0	(0.4)
17	Load Variance Recoveries	4.0 L62				82.7	0.0	(82.7)	217.8	217.8	0.0	0.0
18	Biomass Energy Program Variance Recoveries	4.0 L63	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Total Current		1,715.8	1,854.1	1,909.4	1,634.8	1,552.5	(82.3)	1,537.7	1,376.0	(161.7)	1,669.8
	Operating Costs											
20	Total Gross	5.0 L65	1,101.5	1,076.4	1,165.1	1,136.1	1,115.2	(20.9)	1,135.4	1,148.4	13.0	1,228.5
21	Deferral Account Additions	5.0 L51	9.0	35.3	0.7	0.0	1.4	1.4	0.0	0.7	0.7	0.0
22	Regulatory Account Additions	5.0 L64	(242.9)	(179.8)	(198.7)	(159.0)	(132.6)	26.4	(125.4)	(112.4)	12.9	(102.0)
23	Subtotal before Recoveries		867.6	931.9	967.1	977.1	984.0	6.9	1,010.0	1,036.6	26.6	1,126.5
24	Regulatory Account Recoveries	5.0 L36	202.3	217.9	215.4	218.7	223.6	4.9	216.7	216.6	(0.1)	225.8
25	Total Current		1,069.9	1,149.8	1,182.4	1,195.8	1,207.6	11.8	1,226.7	1,253.2	26.5	1,352.3
	Provisions & Other											
26	Total Gross	5.01 L43	63.6	152.3	111.9	116.4	176.8	60.4	95.4	197.9	102.5	101.4
27	Deferral Account Additions	5.01 L34	0.0	(1.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Regulatory Account Additions	5.01 L42	19.5	(35.4)	(16.0)	0.0	(48.0)	(48.0)	0.0	(102.2)	(102.2)	0.0
29	Subtotal before Recoveries		83.0	115.2	95.9	116.4	128.7	12.4	95.4	95.6	0.2	101.4
30	Regulatory Account Recoveries	5.01 L25	(162.0)	(292.2)	848.6	46.3	46.3	(0.0)	43.3	43.3	0.0	63.9
31	Total Current		(79.0)	(177.0)	944.4	162.6	175.0	12.4	138.7	138.9	0.2	165.3
	Taxes											
32	Total Gross	6.0 L21	223.1	231.1	242.7	249.8	249.7	(0.1)	262.2	254.8	(7.4)	263.8
33	Deferral Account Additions	6.0 L22	0.4	1.9	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Total Current		223.5	232.9	242.7	249.8	249.7	(0.1)	262.2	254.8	(7.4)	263.8

BC Hydro **Schedule 3.0**
F22 RRA Compliance **Page 14**

Reconciliation of Current and Gross Views
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Amortization											
35	Total Gross	7.0 L17	777.9	807.6	871.3	977.8	977.7	(0.0)	998.0	996.6	(1.3)	1,023.7
36	Deferral Account Additions	7.0 L14	3.3	14.0	0.0	0.0	(0.4)	(0.4)	0.0	0.2	0.2	0.0
37	Regulatory Account Additions	7.0 L19	2.0	(0.7)	(20.4)	(0.2)	0.4	0.7	(0.5)	1.1	1.6	(0.5)
38	Subtotal before Recoveries		783.2	821.0	850.9	977.5	977.8	0.3	997.5	998.0	0.5	1,023.1
39	Regulatory Account Recoveries	7.0 L35	77.5	95.4	100.9	118.1	118.1	(0.0)	121.9	121.0	(0.9)	111.1
40	Total Current		860.7	916.3	951.8	1,095.7	1,095.9	0.3	1,119.4	1,119.0	(0.4)	1,134.2
	Finance Charges											
41	Total Gross	8.0 L1	579.2	805.9	1,192.2	874.9	1,656.8	781.8	743.3	951.5	208.2	555.6
42	Total Finance Charge Regulatory Acct. Additions	8.0 L21	12.6	25.1	(52.8)	0.0	(0.9)	(0.9)	0.0	76.6	76.6	0.0
43	Other Regulatory Account Additions	8.0 L3-L8+L22	162.4	(46.9)	(348.5)	(119.8)	(803.1)	(683.3)	(18.6)	(201.8)	(183.2)	(11.9)
44	Interest on Regulatory Accounts	8.0 L25	(75.3)	(61.6)	(27.5)	(17.7)	(16.7)	1.0	(26.0)	(22.3)	3.7	(24.5)
45	Subtotal before Recoveries		678.8	722.5	763.5	737.5	836.1	98.6	698.7	803.9	105.2	519.3
46	Regulatory Account Recoveries	8.0 L31	(174.9)	(209.4)	(207.9)	(1.7)	(100.3)	(98.6)	(2.8)	(108.3)	(105.6)	(65.2)
47	Total Current		504.0	513.1	555.6	735.8	735.8	(0.0)	696.0	695.6	(0.4)	454.1
	Return on Equity											
48	Total Gross	9.0 L33	683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
49	Subtotal before Recoveries		683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
50	Regulatory Account Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	Total Current		683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
	Miscellaneous Revenue											
52	Total Gross	15.0 L40	(143.1)	(143.7)	(224.4)	(240.6)	(247.3)	(6.7)	(247.0)	(243.7)	3.3	(289.0)
53	Deferral Account Additions	15.0 L36	0.0	0.0	51.9	3.1	1.3	(1.8)	3.5	3.5	0.0	15.5
54	Regulatory Account Additions	15.0 L39	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
55	Subtotal before Recoveries		(143.4)	(143.7)	(172.5)	(237.5)	(246.0)	(8.5)	(243.6)	(240.2)	3.3	(273.5)
56	Total Current	15.0 L43	(143.4)	(143.7)	(172.5)	(237.5)	(246.0)	(8.5)	(243.6)	(240.2)	3.3	(273.5)
	Inter-Segment Revenue											
57	Powerex - Business Support Allocation	3.1 L15	(2.8)	(2.8)	(2.9)	(2.9)	(2.9)	0.0	(2.9)	(2.9)	0.0	(2.9)
58	Mark to Market Losses (Gains)	3.1 L16	(0.2)	(1.0)	1.0	(1.4)	0.8	2.2	0.0	(9.3)	(9.3)	0.0
59	Powerex PTP Charges	3.4 L19	(9.6)	(21.2)	(26.4)	(41.5)	(49.8)	(8.3)	(34.0)	(21.3)	12.6	(34.4)
60	BC Hydro PTP Charges	3.4 L20	(44.3)	(41.3)	(34.3)	(19.1)	(20.1)	(1.0)	(35.0)	(63.8)	(28.8)	(46.3)
61	Total		(56.9)	(66.4)	(62.5)	(64.9)	(72.0)	(7.1)	(71.9)	(97.4)	(25.5)	(83.5)

BC Hydro Schedule 3.0
F22 RRA Compliance Page 15

Reconciliation of Current and Gross Views
($ million)

Line		Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
				1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Powerex Trade Income												
62	Total Gross		1.0 L18	(130.2)	(136.6)	(435.7)	(176.3)	(189.2)	(13.0)	(176.3)	(176.2)	0.0	(158.7)
63	TIDA Additions		2.1 L17	15.1	21.4	320.5	0.0	68.7	68.7	0.0	0.0	0.0	0.0
64	TIDA Recoveries		2.1 L19	48.9	50.5	62.7	(159.5)	(164.2)	(4.7)	(109.8)	(109.8)	0.0	0.0
65	Total Current			(66.2)	(64.7)	(52.4)	(335.8)	(284.8)	51.0	(286.1)	(286.0)	0.0	(158.7)
66	**Powertech Net Income**		1.0 L19	(2.1)	(3.1)	(3.5)	(3.4)	(3.4)	0.0	(3.7)	0.0	3.7	(2.0)
67	**Other Utilities Revenue**		14.0 L19	(13.0)	(11.9)	(29.6)	(36.1)	(29.7)	6.4	(35.9)	(30.2)	5.7	(30.2)
68	**Liquefied Natural Gas Revenue**		14.0 L20	(0.4)	(1.3)	(1.8)	(0.5)	(1.3)	(0.7)	0.0	0.0	0.0	0.0
69	**Deferral Account Rate Rider Revenue**		14.0 L23	(223.7)	(233.2)	(240.6)	0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)	0.0
70	**Total Rate Revenue Requirement (Current)**			4,472.6	4,649.1	4,795.2	5,108.1	5,084.0	(24.2)	5,051.6	4,874.3	(177.2)	5,203.6
	Summary - Current Rates View												
71	Cost of Energy		Line 19	1,715.8	1,854.1	1,909.4	1,634.8	1,552.5	(82.3)	1,537.7	1,376.0	(161.7)	1,669.8
72	Operating Costs		Line 25	1,069.9	1,149.8	1,182.4	1,195.8	1,207.6	11.8	1,226.7	1,253.2	26.5	1,352.3
73	Provisions & Other		Line 31	(79.0)	(177.0)	944.4	162.6	175.0	12.4	138.7	138.9	0.2	165.3
74	Taxes		Line 34	223.5	232.9	242.7	249.8	249.7	(0.1)	262.2	254.8	(7.4)	263.8
75	Amortization		Line 40	860.7	916.3	951.8	1,095.7	1,095.9	0.3	1,119.4	1,119.0	(0.4)	1,134.2
76	Finance Charges		Line 47	504.0	513.1	555.6	735.8	735.8	(0.0)	696.0	695.6	(0.4)	454.1
77	Return on Equity		Line 51	683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
78	Miscellaneous Revenues		Line 56	(143.4)	(143.7)	(172.5)	(237.5)	(246.0)	(8.5)	(243.6)	(240.2)	3.3	(273.5)
79	Inter-Segment Revenue		Line 61	(56.9)	(66.4)	(62.5)	(64.9)	(72.0)	(7.1)	(71.9)	(97.4)	(25.5)	(83.5)
80	Subsidiary Net Income		L65+L66	(68.4)	(67.7)	(55.9)	(339.2)	(288.2)	51.0	(289.7)	(286.0)	3.7	(160.7)
81	Other Utilities Revenue		Line 67	(13.0)	(11.9)	(29.6)	(36.1)	(29.7)	6.4	(35.9)	(30.2)	5.7	(30.2)
82	Liquefied Natural Gas Revenue		Line 68	(0.4)	(1.3)	(1.8)	(0.5)	(1.3)	(0.7)	0.0	0.0	0.0	0.0
83	Deferral Account Rate Rider Revenue		Line 69	(223.7)	(233.2)	(240.6)	0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)	0.0
84	Total Rate Revenue Requirement			4,472.6	4,649.1	4,795.2	5,108.1	5,084.0	(24.2)	5,051.6	4,874.3	(177.2)	5,203.6
	Allocation of Current Costs												
85	Generation		3.2 L18	1,408.1	1,371.9	1,513.3	1,695.6	1,757.3	61.7	1,428.9	1,428.2	(0.7)	1,743.2
86	Transmission		3.4 L22	830.5	828.8	824.5	972.2	983.2	11.0	968.8	962.9	(5.8)	982.0
87	Distribution		3.5 L16	972.4	974.9	965.2	1,209.2	1,204.0	(5.2)	1,218.8	1,204.3	(14.5)	1,189.0
88	Customer Care		3.3 L11	1,567.0	1,787.6	1,820.1	1,607.0	1,458.8	(148.1)	1,760.7	1,595.1	(165.5)	1,480.2
89	Business Support		3.1 L18	(0.0)	(0.0)	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)
90	Subsidiary Net Income		Line 80	(68.4)	(67.7)	(55.9)	(339.2)	(288.2)	51.0	(289.7)	(286.0)	3.7	(160.7)
91	Other Utilities Revenue		Line 81	(13.0)	(11.9)	(29.6)	(36.1)	(29.7)	6.4	(35.9)	(30.2)	5.7	(30.2)
92	Liquefied Natural Gas Revenue		Line 82	(0.4)	(1.3)	(1.8)	(0.5)	(1.3)	(0.7)	0.0	0.0	0.0	0.0
93	Deferral Account Rate Rider Revenue		Line 83	(223.7)	(233.2)	(240.6)	0.0	(0.2)	(0.2)	0.0	(0.0)	(0.0)	0.0
94	Total Rate Revenue Requirement			4,472.6	4,649.1	4,795.2	5,108.1	5,084.0	(24.2)	5,051.6	4,874.3	(177.2)	5,203.6

BC Hydro **Schedule 3.1**
F22 RRA Compliance **Page 16**

Total Current Costs - Business Support
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	**Current Operating Costs**	3.6 L6 (Prior F21: 3.6 L60:L61)	291.9	378.5	435.8	438.9	462.5	23.6	465.8	471.9	6.1	571.0
2	**Current Provisions & Other**	5.01 L31	(204.8)	(310.9)	826.3	1.3	(6.8)	(8.1)	0.6	1.0	0.5	13.2
3	**Taxes**	6.0 L28	15.7	16.5	17.0	18.2	17.7	(0.5)	18.7	16.1	(2.6)	18.2
4	**Current Amortization**	7.0 L41	167.0	181.7	166.1	202.8	199.4	(3.4)	202.7	201.2	(1.5)	192.8
5	**Business Support Allocation**	Line 54 (Prior F19: L59)	(369.9)	(328.7)	(356.2)	(711.8)	(725.4)	(13.6)	(739.9)	(737.1)	2.7	(820.6)
6	**Miscellaneous Revenue**	15.0 L31	(19.5)	(19.4)	(17.4)	(16.1)	(16.4)	(0.2)	(16.4)	(11.9)	4.5	(47.1)
	Internal Allocations											
7	Generation Capitalized Overhead		**8.8**	**7.7**	**9.4**	**9.4**	**9.4**	0.0	**9.4**	**9.1**	(0.3)	**9.7**
8	Transmission Capitalized Overhead		**16.0**	**16.9**	**17.8**	**16.1**	**16.1**	0.0	**16.3**	**15.6**	(0.6)	**16.6**
9	Distribution Capitalized Overhead		**42.1**	**44.4**	**43.2**	**45.5**	**45.5**	0.0	**45.7**	**46.3**	0.6	**49.2**
10	Generation RSRA Write-off	9.0 L43			(500.3)			0.0			0.0	
11	Transmission RSRA Write-off	9.0 L44			(390.9)			0.0			0.0	
12	Distribution RSRA Write-off	9.0 L45			(249.0)			0.0			0.0	
13	Adj to align with prior approved RRA		**55.5**	**17.1**				0.0			0.0	
14	Total		122.5	86.1	(1,069.8)	71.0	71.0	0.0	71.4	71.0	(0.3)	75.5
	Inter-Segment Revenue											
15	Powerex - Business Support Allocation		**(2.8)**	**(2.8)**	**(2.9)**	**(2.9)**	**(2.9)**	0.0	**(2.9)**	**(2.9)**	0.0	**(2.9)**
16	Mark to Market Losses (Gains)		**(0.2)**	**(1.0)**	**1.0**	**(1.4)**	**0.8**	2.2	**0.0**	**(9.3)**	(9.3)	**0.0**
17	Total		(3.0)	(3.8)	(1.8)	(4.3)	(2.1)	2.2	(2.9)	(12.2)	(9.3)	(2.9)
18	**Total**		(0.0)	(0.0)	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)
	Internal Allocation by Function:											
	Insurance											
19	Generation		**4.2**	**4.2**	**4.2**	**4.3**	**4.3**	0.0	**4.3**	**4.3**	0.0	**0.0**
20	Transmission		**2.5**	**2.5**	**2.4**	**2.4**	**2.4**	0.0	**2.4**	**2.4**	0.0	**0.0**
21	Distribution		**2.5**	**2.5**	**2.6**	**2.6**	**2.6**	0.0	**2.6**	**2.7**	0.1	**0.0**
22	Customer Care		**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	0.0	**0.5**	**0.5**	0.0	**0.0**
23	Total		9.7	9.7	9.7	9.7	9.7	0.0	9.7	9.9	0.2	0.0
	Non-Current/Current Pension Costs											
24	Generation		**24.2**	**17.1**	**28.1**	**24.5**	**24.5**	0.0	**24.9**	**24.9**	(0.0)	**0.0**
25	Transmission		**32.6**	**23.0**	**29.7**	**25.7**	**25.7**	0.0	**25.5**	**26.1**	0.6	**0.0**
26	Distribution		**31.7**	**22.3**	**28.5**	**25.9**	**25.9**	0.0	**25.7**	**25.1**	(0.6)	**0.0**
27	Customer Care		**6.4**	**4.5**	**12.9**	**10.0**	**10.0**	0.0	**10.0**	**10.0**	(0.0)	**0.0**
28	Total		94.9	66.9	99.2	86.1	86.1	0.0	86.1	86.1	(0.0)	0.0

BC Hydro Schedule 3.1
F22 RRA Compliance Page 17

Total Current Costs - Business Support
($ million)

Line	Reference Column	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Fleet/MMBU										
29	Generation	7.2	7.5	8.2	8.5	8.5	0.0	8.6	8.5	(0.1)	9.7
30	Transmission	25.2	26.1	22.5	23.3	23.3	0.0	23.6	21.1	(2.6)	22.6
31	Distribution	47.7	49.5	52.8	54.6	54.6	0.0	55.4	59.0	3.6	63.4
32	Customer Care	0.0	0.0	1.3	1.3	1.3	0.0	1.3	1.3	(0.0)	1.3
33	Total	80.1	83.1	84.8	87.6	87.6	0.0	89.0	90.0	1.0	97.1
	Total Direct Assignments										
34	Generation	35.6	28.7	40.6	37.3	37.3	0.0	37.8	37.8	(0.0)	9.7
35	Transmission	60.3	51.7	54.6	51.3	51.3	0.0	51.5	49.6	(1.9)	22.6
36	Distribution	82.0	74.3	83.8	83.1	83.1	0.0	83.7	86.8	3.1	63.4
37	Customer Care	6.9	5.0	14.7	11.8	11.8	0.0	11.8	11.8	(0.0)	1.3
38	Business Support	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Total	184.8	159.7	193.7	183.4	183.4	0.0	184.8	185.9	1.1	97.1
	Allocators for Balance - %										
40	Generation	28.4%	28.4%	28.4%	28.5%	28.5%	-	28.9%	28.9%	-	29.0%
41	Transmission	28.1%	28.1%	28.1%	28.8%	28.8%	-	28.5%	28.5%	-	29.9%
42	Distribution	30.5%	30.5%	30.5%	31.2%	31.2%	-	30.9%	30.9%	-	32.4%
43	Customer Care	13.0%	13.0%	13.0%	11.6%	11.6%	-	11.6%	11.6%	-	8.7%
44	Total	100.0%	100.0%	100.0%	100.0%	100.0%	-	100.0%	100.0%	-	100.0%
	Allocation of Balance										
45	Generation	52.5	47.9	46.1	150.6	154.4	3.9	160.7	159.5	(1.1)	209.9
46	Transmission	52.1	47.5	45.7	152.0	155.9	3.9	158.5	157.4	(1.1)	216.4
47	Distribution	56.4	51.5	49.5	164.6	168.8	4.2	171.6	170.4	(1.2)	234.5
48	Customer Care	24.2	22.0	21.2	61.2	62.8	1.6	64.4	63.9	(0.4)	62.8
49	Total	185.2	169.0	162.5	528.4	541.9	13.6	555.1	551.2	(3.8)	723.6
	Total Business Support Allocation										
50	Generation	88.1	76.7	86.7	187.8	191.7	3.9	198.5	197.3	(1.2)	219.6
51	Transmission	112.4	99.2	100.3	203.3	207.2	3.9	209.9	207.0	(3.0)	239.1
52	Distribution	138.4	125.8	133.3	247.7	251.9	4.2	255.3	257.2	1.9	297.9
53	Customer Care	31.1	27.0	35.9	73.0	74.6	1.6	76.2	75.7	(0.5)	64.1
54	Total	369.9	328.7	356.2	711.8	725.4	13.6	739.9	737.1	(2.7)	820.6
	Total Business Support Allocation (Prior Approved RRA)										
55	Generation	90.9	79.4								
56	Transmission	117.7	102.6								
57	Distribution	138.6	126.2								
58	Customer Care	22.8	20.5								
59	Total	369.9	328.7								

BC Hydro
F22 RRA Compliance

Schedule 3.2
Page 18

Total Current Costs - Generation
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	**Cost of Energy**	4.0 L65	272.7	238.8	242.8	229.8	293.4	63.7	(16.3)	(24.0)	(7.7)	378.1
2	**Current Operating Costs**	3.6 L2 (Prior F21: 3.6 L51+L56)	195.9	192.6	209.1	206.5	195.2	(11.3)	210.8	220.8	10.0	221.5
3	**Current Provisions & Other**	5.01 L27	23.9	24.5	25.1	51.1	55.0	3.9	24.8	24.9	0.2	15.1
4	**Taxes**	6.0 L24	40.5	40.9	42.5	44.3	44.2	(0.0)	46.3	45.2	(1.1)	46.1
5	**Current Amortization**	7.0 L37	276.0	284.8	323.8	353.9	355.6	1.8	363.5	368.1	4.6	375.7
6	**Current Finance Charges**	8.0 L37	209.5	212.0	243.8	338.4	339.9	1.5	319.6	321.4	1.9	207.7
7	**Return on Equity**	9.0 L39	284.2	282.6	(187.9)	327.5	325.6	(1.9)	326.9	319.2	(7.8)	325.7
8	**Business Support Allocation**	3.1 L50 (Prior F19: 3.1 L55)	90.9	79.4	86.7	187.8	191.7	3.9	198.5	197.3	(1.2)	219.6
9	**Miscellaneous Revenue**	15.0 L3	(2.3)	(1.9)	(2.3)	(1.9)	(2.5)	(0.6)	(1.9)	(1.7)	0.2	(2.2)
	Internal Allocations											
10	GRTA Allocation	3.4 L9	43.3	43.3	43.3	43.3	43.3	0.0	43.3	43.3	0.0	43.3
11	Generation Real Time Dispatch	3.4 L10	1.6	1.6	1.6	2.4	2.4	0.0	2.4	2.4	(0.0)	3.0
12	Generation Ancillary Services	3.4 L14	(2.0)	(2.7)	(6.0)	(2.8)	(2.1)	0.8	(2.8)	(2.8)	0.0	(2.5)
13	Generation Capitalized Overhead	3.1 L7	(8.8)	(7.7)	(9.4)	(9.4)	(9.4)	0.0	(9.4)	(9.1)	0.3	(9.7)
14	Generation RSRA Write-off	3.1 L10	0.0	0.0	500.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Waneta 2/3 Lease revenue from Teck	3.3 L8	0.0	0.0	0.0	(75.2)	(75.2)	(0.0)	(76.7)	(76.7)	(0.0)	(78.2)
16	Adj to align with prior approved RRA		(17.2)	(16.0)				0.0			0.0	
17	Total		16.9	18.4	529.7	(41.8)	(41.0)	0.8	(43.3)	(42.9)	0.3	(44.1)
18	**Total**		1,408.1	1,371.9	1,513.3	1,695.6	1,757.3	61.7	1,428.9	1,428.2	(0.7)	1,743.2

BC Hydro | **Schedule 3.3**
F22 RRA Compliance | **Page 19**

Total Current Costs - Customer Care
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	**Cost of Energy**	4.0 L67	1,443.0	1,615.4	1,666.5	1,405.0	1,259.0	(145.9)	1,554.0	1,400.0	(154.0)	1,291.7
2	**Current Operating Costs**	3.6 L5 (Prior F21: 3.6 L54+L59)	(0.4)	(4.0)	127.9	78.7	75.0	(3.7)	79.6	67.6	(12.0)	68.9
3	**Current Provisions & Other**	5.01 L30	0.4	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Taxes**	6.0 L27	2.6	4.2	2.6	0.6	0.9	0.3	0.6	0.8	0.2	0.8
5	**Current Amortization**	7.0 L40	17.0	29.4	22.8	88.9	88.9	0.0	90.1	90.1	0.0	90.6
6	**Business Support Allocation**	3.1 L53 (Prior F19: 3.1 L58)	22.8	20.5	35.9	73.0	74.6	1.6	76.2	75.7	(0.5)	64.1
7	**Miscellaneous Revenue**	15.0 L25	(24.9)	(23.4)	(35.6)	(114.5)	(114.8)	(0.3)	(116.4)	(115.7)	0.8	(114.1)
	Internal Allocations											
8	Waneta 2/3 Lease revenue from Teck	15.0 L20				75.2	75.2	0.0	76.7	76.7	0.0	78.2
9	Adj to align with prior approved RRA		106.4	141.5				0.0			0.0	
10	Total		106.4	141.5	0.0	75.2	75.2	0.0	76.7	76.7	0.0	78.2
11	**Total**		1,567.0	1,787.6	1,820.1	1,607.0	1,458.8	(148.1)	1,760.7	1,595.1	(165.5)	1,480.2

BC Hydro
F22 RRA Compliance

Schedule 3.4
Page 20

Total Current Costs - Transmission
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	**Current Operating Costs**	3.6 L3	403.7	398.2	228.0	219.4	206.4	(13.1)	220.5	226.2	5.7	247.2
2	**Current Provisions & Other**	(Prior F21: 3.6 L52+L57) 5.01 L28	47.2	56.8	34.4	33.8	48.7	14.9	37.3	37.8	0.5	62.8
3	**Taxes**	6.0 L25	137.9	143.8	152.3	157.6	158.4	0.8	163.7	163.1	(0.6)	167.0
4	**Current Amortization**	7.0 L38	215.7	225.8	229.0	233.5	234.4	0.8	236.1	233.9	(2.2)	239.2
5	**Current Finance Charges**	8.0 L38	178.7	182.5	190.5	243.9	243.0	(0.9)	227.6	226.8	(0.8)	148.3
6	**Return on Equity**	9.0 L40	242.4	243.2	(146.8)	236.1	232.8	(3.2)	232.9	225.2	(7.7)	232.5
7	**Business Support Allocation**	3.1 L51	117.7	102.6	100.3	203.3	207.2	3.9	209.9	207.0	(3.0)	239.1
8	**Miscellaneous Revenue**	(Prior F19: 3.1 L56) 15.0 L10	(44.1)	(43.3)	(57.6)	(46.1)	(46.4)	(0.3)	(46.8)	(46.8)	0.1	(41.4)
	Internal Allocations:											
9	GRTA Allocation		**(43.3)**	**(43.3)**	**(43.3)**	**(43.3)**	**(43.3)**	0.0	**(43.3)**	**(43.3)**	0.0	**(43.3)**
10	Generation Real Time Dispatch		**(1.6)**	**(1.6)**	**(1.6)**	**(2.4)**	**(2.4)**	(0.0)	**(2.4)**	**(2.4)**	0.0	**(3.0)**
11	Distribution Real Time Dispatch		**(16.7)**	**(16.4)**	**(16.7)**	**(20.6)**	**(20.8)**	(0.2)	**(21.0)**	**(20.9)**	0.1	**(25.7)**
12	SDA Allocation to Distribution		**(125.6)**	**(127.6)**	**(126.6)**	**(125.6)**	**(127.0)**	(1.4)	**(127.4)**	**(145.8)**	(18.3)	**(149.3)**
13	PTP Allocation to Distribution	L21 + L68	(26.7)	(28.3)	(35.7)	(43.6)	(23.9)	19.7	(36.0)	(0.0)	35.9	3.3
14	Generation Ancillary Services		**2.0**	**2.7**	**6.0**	**2.8**	**2.1**	(0.8)	**2.8**	**2.8**	0.0	**2.5**
15	Transmission Capitalized Overhead	3.1 L8	(16.0)	(16.9)	(17.8)	(16.1)	(16.1)	0.0	(16.3)	(15.6)	0.6	(16.6)
16	Transmission RSRA Write-off	3.1 L11	0.0	0.0	390.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Adj to align with prior approved RRA		**(186.9)**	**(187.0)**				0.0			0.0	
18	Total		(414.8)	(418.2)	155.3	(248.7)	(231.3)	17.4	(243.5)	(225.2)	18.3	(232.1)
	Inter-Segment Revenue											
19	Powerex PTP Charges		**(9.6)**	**(21.2)**	**(26.4)**	**(41.5)**	**(49.8)**	(8.3)	**(34.0)**	**(21.3)**	12.6	**(34.4)**
20	BC Hydro PTP Charges		**(44.3)**	**(41.3)**	**(34.3)**	**(19.1)**	**(20.1)**	(1.0)	**(35.0)**	**(63.8)**	(28.8)	**(46.3)**
21	Total		(53.9)	(62.6)	(60.7)	(60.6)	(69.9)	(9.3)	(69.0)	(85.1)	(16.1)	(80.6)
22	**Total Current Costs**		830.5	828.8	824.5	972.2	983.2	11.0	968.8	962.9	(5.8)	982.0
	Transmission Revenue Requirement											
23	Total Current Costs	Line 22	830.5	828.8	824.5	972.2	983.2	11.0	968.8	962.9	(5.8)	982.0
24	Adj to offset re-org impact							0.0			0.0	
25	Adj. Total Current Costs		830.5	828.8	824.5	972.2	983.2	11.0	968.8	962.9	(5.8)	982.0
26	PTP Allocation to Distribution	Line 13	26.7	28.3	35.7	43.6	23.9	(19.7)	36.0	0.0	(35.9)	(3.3)
27	Inter-Segment Revenue	Line 21	53.9	62.6	60.7	60.6	69.9	9.3	69.0	85.1	16.1	80.6
28	External OATT Revenue	Line 74	11.8	11.4	15.4	15.9	10.7	(5.2)	15.9	12.9	(3.0)	11.1
29	Total TRR		923.0	931.1	936.4	1,092.3	1,087.7	(4.7)	1,089.6	1,061.0	(28.6)	1,070.4

BC Hydro | **Schedule 3.4**
F22 RRA Compliance | **Page 21**

Total Current Costs - Transmission
($ million)

			F2017	F2018	F2019	F2020			F2021			F2022
		Reference	Actual	Actual	Actual	Decision	Actual	Diff	Decision	Forecast	Diff	Decision
Line	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	NITS Charge to BC Hydro											
30	Adj. Total Current Costs	Line 25				972.2			968.8	962.9		982.0
31	Internal Ancillary Services	Line 36				0.0			0.0	0.0		0.0
32	Internal Scheduling & Dispatch	Line 38				(3.8)			(3.9)	(3.8)		(3.7)
33	Total		820.1	826.2	813.0	968.4	928.2	(40.2)	964.8	959.1	(5.7)	978.3
34	NITS Monthly Rate	Line 33 / 12	68.3	68.9	67.8	80.7	77.4		80.4	79.9		81.5
	Long-Term PTP Rate											
35	Total TRR	Line 29				1,092.3			1,089.6	1,061.0		1,070.4
36	Internal Ancillary Services		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	External Ancillary Services		(2.0)	(2.7)	(6.0)	(2.8)	(2.1)	0.8	(2.8)	(2.8)	0.0	(2.5)
38	Internal Scheduling & Dispatch		(2.7)	(2.6)	(3.0)	(3.8)	(3.5)	0.4	(3.9)	(3.8)	0.1	(3.7)
39	External Scheduling & Dispatch		(0.2)	(0.1)	(0.2)	(0.2)	(0.1)	0.1	(0.2)	(0.2)	(0.0)	(0.2)
40	Total					1,085.4			1,082.7	1,054.1		1,064.0
41	Maximum Supply (MW)		12,978	13,124	13,171	13,279	13,279		13,279	13,279		13,596
42	Long-Term Firm PTP Rate ($/MW/year)		70,687	70,451	70,702	81,741	78,490		81,531	79,383		78,262
	Maximum Price for Short-Term Firm and Non-Firm (per MW of Reserved Capacity)											
43	Monthly ($/MW/month)		5,890.60	5,870.95	5,891.87	6,811.71	6,540.80		6,794.28	6,615.27		6,521.81
44	Weekly ($/MW/week)		1,359.37	1,354.83	1,359.66	1,571.93	1,509.42		1,567.91	1,526.60		1,505.03
45	Daily ($/MW/day)		193.66	193.02	193.71	223.95	215.04		223.37	217.49		214.42
46	Hourly ($/MW/hour)		8.07	8.04	8.07	9.33	8.96		9.31	9.06		8.93
	Scheduling Fee											
47	Scheduling, Control & Dispatch	L38 + L39	2.9	2.7	3.1	4.1	3.6		4.1	4.0		3.9
48	Total Volume (GWh)		25,664	27,707	29,543	29,388	27,093		29,773	26,589		25,496
49	Scheduling Fee ($/MWh)	L47 / L48	0.113	0.099	0.106	0.138	0.133		0.139	0.152		0.152
	Long-Term PTP Volumes (GWh)											
50	Internal		8,226	8,448	8,609	8,567	9,242	675	8,567	8,338	(230)	7,577
51	External		1,130	908	876	1,314	878	(436)	1,314	949	(365)	876
52	Total		9,356	9,356	9,485	9,881	10,121	239	9,881	9,287	(595)	8,453
	Long-Term PTP Revenue											
53	Internal	L46 * L50	65.9	68.0	69.6	79.9	82.8	2.9	79.8	75.5	(4.2)	67.7
54	External	L46 * L51	9.1	7.3	6.9	12.3	7.9	(4.4)	12.2	8.6	(3.6)	7.8
55	Total		74.9	75.2	76.6	92.2	90.7	(1.5)	92.0	84.1	(7.9)	75.5
	Long-Term PTP Average Price ($/MWh)											
56	Internal	L53 / L50	8.01	8.05	8.09	9.33	8.96	(0.37)	9.31	9.06	(0.25)	8.93
57	External	L54 / L51	8.01	8.02	7.89	9.33	8.96	(0.37)	9.31	9.06	(0.25)	8.93
58	Total	L55 / L52	8.01	8.04	8.07	9.33	8.96	(0.37)	9.31	9.06	(0.25)	8.93

BC Hydro **Schedule 3.4**
F22 RRA Compliance **Page 22**

Total Current Costs - Transmission
($ million)

Line		Column / Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Short-Term PTP Volumes (GWh)											
59	Internal		6,608	8,338	7,093	9,700	3,848	(5,852)	10,085	3,848	(6,237)	3,848
60	External		288	446	657	240	170	(70)	240	500	260	240
61	Total		6,897	8,785	7,750	9,940	4,017	(5,923)	10,325	4,348	(5,977)	4,088
	Short-Term PTP Revenue											
62	Internal		14.8	22.9	26.7	24.2	11.0	(13.3)	25.2	9.6	(15.6)	9.6
63	External		0.6	1.2	2.3	0.6	0.6	(0.0)	0.6	1.3	0.7	0.6
64	Total		15.4	24.2	29.1	24.8	11.5	(13.3)	25.8	10.9	(14.9)	10.2
	Short-Term PTP Average Price ($/MWh)											
65	Internal	L62 / L59	2.24	2.75	3.77	2.50	2.85	0.35	2.50	2.50	0.00	2.50
66	External	L63 / L60	2.24	2.75	3.52	2.50	3.46	0.96	2.50	2.50	0.00	2.50
67	Total	L64 / L61	2.24	2.75	3.75	2.50	2.87	0.37	2.50	2.50	0.00	2.50
	Total PTP Revenue											
68	Internal	L53 + L62	80.7	90.9	96.4	104.2	93.8	(10.4)	105.0	85.2	(19.8)	77.3
69	External	L54 + L63	9.7	8.5	9.2	12.9	8.5	(4.4)	12.8	9.8	(3.0)	8.4
70	Total		90.4	99.4	105.6	117.0	102.2	(14.8)	117.8	95.0	(22.8)	85.7
	Total External OATT Revenue											
71	Total External PTP	Line 69	9.7	8.5	9.2	12.9	8.5	(4.4)	12.8	9.8	(3.0)	8.4
72	External Ancillary Services	Line 37	2.0	2.7	6.0	2.8	2.1	(0.8)	2.8	2.8	0.0	2.5
73	External Scheduling & Dispatch	Line 39	0.2	0.1	0.2	0.2	0.1	(0.1)	0.2	0.2	0.0	0.2
74	Total		11.8	11.4	15.4	15.9	10.7	(5.2)	15.9	12.9	(3.0)	11.1

BC Hydro | **Schedule 3.5**
F22 RRA Compliance | **Page 23**

Total Current Costs - Distribution
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	**Current Operating Costs**	3.6 L4 (Prior F21: 3.6 L53+L58)	178.8	184.5	181.7	252.2	268.5	16.3	250.0	266.8	16.8	243.6
2	**Current Provisions & Other**	5.01 L29	54.2	48.5	58.6	76.4	78.0	1.6	76.1	75.1	(0.9)	74.2
3	**Taxes**	6.0 L26	26.8	27.5	28.3	29.1	28.6	(0.6)	32.9	29.5	(3.3)	31.7
4	**Current Amortization**	7.0 L39	184.9	194.7	210.1	216.5	217.6	1.1	227.0	225.8	(1.2)	235.9
5	**Current Finance Charges**	8.0 L39	115.7	118.7	121.3	153.4	152.8	(0.6)	148.8	147.4	(1.4)	98.1
6	**Return on Equity**	9.0 L41	157.0	158.2	(93.5)	148.4	146.4	(2.0)	152.2	146.3	(5.9)	153.8
7	**Business Support Allocation**	3.1 L52 (Prior F19: 3.1 L57)	138.6	126.2	133.3	247.7	251.9	4.2	255.3	257.2	1.9	297.9
8	**Miscellaneous Revenue**	15.0 L13	(52.7)	(55.7)	(59.5)	(58.9)	(66.0)	(7.1)	(62.0)	(64.2)	(2.2)	(68.6)
	Internal Allocations											
9	Distribution Real Time Dispatch	3.4 L11	16.7	16.4	16.7	20.6	20.8	0.2	21.0	20.9	(0.1)	25.7
10	SDA Allocation from Transmission	3.4 L12	125.6	127.6	126.6	125.6	127.0	1.4	127.4	145.8	18.3	149.3
11	PTP Allocation to Distribution	3.4 L13	26.7	28.3	35.7	43.6	23.9	(19.7)	36.0	0.0	(35.9)	(3.3)
12	Distribution Capitalized Overhead	3.1 L9	(42.1)	(44.4)	(43.2)	(45.5)	(45.5)	0.0	(45.7)	(46.3)	(0.6)	(49.2)
13	Distribution RSRA Write-off	3.1 L12	0.0	0.0	249.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Adj to align with prior approved RRA		**42.1**	**44.4**				0.0			0.0	
15	Total		169.0	172.2	384.8	144.3	126.2	(18.1)	138.7	120.4	(18.3)	122.4
16	**Total**		972.4	974.9	965.2	1,209.2	1,204.0	(5.2)	1,218.8	1,204.3	(14.5)	1,189.0

BC Hydro
F22 RRA Compliance

Total Current Operating Costs and Provisions
($ million)

			F2017	F2018	F2019	F2020			F2021			F2022
		Reference	Actual	Actual	Actual	Decision	Actual	Diff	Decision	Forecast	Diff	Decision
Line	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	**Total Current Operating Costs**	5.0 L48	1,069.9	1,149.8	1,182.4	1,195.8	1,207.6	11.8	1,226.7	1,253.2	26.5	1,352.3
	Total Internal Allocation											
2	Generation		(205.4)	(204.4)	(202.6)	(213.4)	(207.5)	5.9	(216.8)	(220.8)	(4.0)	(221.5)
3	Transmission		(208.7)	(212.3)	(216.5)	(220.7)	(221.1)	(0.4)	(221.8)	(226.2)	(4.3)	(247.2)
4	Distribution		(202.7)	(206.7)	(219.3)	(253.2)	(260.4)	(7.2)	(251.5)	(266.8)	(15.2)	(243.6)
5	Customer Care		(100.0)	(134.8)	(120.7)	(69.8)	(67.4)	2.4	(70.4)	(67.6)	2.8	(68.9)
6	Business Support		(353.2)	(391.7)	(423.3)	(438.8)	(451.2)	(12.5)	(466.1)	(471.9)	(5.8)	(571.0)
7	Total		(1,069.9)	(1,149.8)	(1,182.5)	(1,195.8)	(1,207.6)	(11.8)	(1,226.7)	(1,253.2)	(26.5)	(1,352.3)
8	**Total**		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total Internal Allocation by BG											
	Integrated Planning											
9	Generation	3.7 L2	(107.2)	(105.6)	(99.0)	(102.0)	(98.1)	3.9	(103.4)	(103.5)	(0.1)	(110.2)
10	Transmission	3.7 L3	(114.5)	(111.7)	(115.7)	(118.5)	(118.4)	0.1	(120.0)	(120.0)	0.0	(139.2)
11	Distribution	3.7 L4	(63.0)	(66.0)	(74.1)	(73.5)	(76.8)	(3.3)	(72.9)	(77.4)	(4.5)	(98.1)
12	Customer Care	3.7 L5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Business Support	3.7 L6	(3.2)	(3.3)	(3.7)	(4.4)	(4.5)	(0.1)	(4.8)	(5.8)	(1.1)	(5.6)
14	Total	3.7 L7	(287.9)	(286.6)	(292.5)	(298.4)	(297.8)	0.6	(301.1)	(306.7)	(5.6)	(353.0)
	Capital Infrastructure Project Delivery											
15	Generation	3.8 L2	(47.1)	(50.2)	(52.3)	(53.2)	(52.5)	0.6	(54.4)	(54.2)	0.2	(49.4)
16	Transmission	3.8 L3	(31.7)	(35.6)	(36.3)	(32.0)	(31.6)	0.5	(30.8)	(30.5)	0.3	(33.4)
17	Distribution	3.8 L4	(5.6)	(5.3)	(5.7)	(5.6)	(5.5)	0.1	(5.4)	(5.4)	0.0	(6.1)
18	Customer Care	3.8 L5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Business Support	3.8 L6	(32.1)	(32.4)	(35.8)	(29.2)	(29.8)	(0.6)	(29.4)	(29.7)	(0.3)	(29.8)
20	Total	3.8 L7	(116.5)	(123.4)	(130.1)	(120.0)	(119.5)	0.5	(120.0)	(119.8)	0.2	(118.7)
	Operations											
21	Generation	3.9 L2	(51.2)	(48.7)	(51.3)	(58.3)	(56.9)	1.4	(59.0)	(63.1)	(4.1)	(61.9)
22	Transmission	3.9 L3	(62.4)	(64.9)	(64.5)	(69.3)	(70.3)	(1.0)	(70.2)	(74.9)	(4.7)	(73.6)
23	Distribution	3.9 L4	(101.5)	(103.6)	(108.4)	(144.6)	(148.4)	(3.8)	(144.7)	(155.5)	(10.8)	(112.9)
24	Customer Care	3.9 L5	(1.4)	(1.9)	(2.7)	(1.4)	(1.9)	(0.5)	(1.4)	0.0	1.4	0.0
25	Business Support	3.9 L6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Total	3.9 L7	(216.5)	(219.1)	(226.9)	(273.6)	(277.5)	(3.9)	(275.3)	(293.5)	(18.1)	(248.5)
	Safety											
27	Generation	3.10 L2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Transmission	3.10 L3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Distribution	3.10 L4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Customer Care	3.10 L5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Business Support	3.10 L6	(56.6)	(54.2)	(54.4)	(57.8)	(56.4)	1.4	(58.5)	(69.6)	(11.1)	(68.3)
32	Total	3.10 L7	(56.6)	(54.2)	(54.4)	(57.8)	(56.4)	1.4	(58.5)	(69.6)	(11.1)	(68.3)

BC Hydro | **Schedule 3.6**
F22 RRA Compliance | **Page 25**

Total Current Operating Costs and Provisions
($ million)

Line	Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Finance, Technology, Supply Chain											
33	Generation	3.11 L2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Transmission	3.11 L3	0.0	0.0	0.0	(0.8)	(0.8)	0.0	(0.8)	(0.8)	0.0	(1.0)
35	Distribution	3.11 L4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Customer Care	3.11 L5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Business Support	3.11 L6	(253.8)	(246.7)	(261.2)	(261.8)	(264.2)	(2.5)	(263.9)	(280.6)	(16.6)	(298.1)
38	Total	3.11 L7	(253.8)	(246.7)	(261.2)	(262.6)	(265.1)	(2.5)	(264.8)	(281.4)	(16.6)	(299.1)
	People, Customer, Corporate Affairs											
39	Generation	3.12 L2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	Transmission	3.12 L3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Distribution	3.12 L4	(32.6)	(31.8)	(31.1)	(29.4)	(29.6)	(0.2)	(28.5)	(28.5)	0.0	(26.6)
42	Customer Care	3.12 L5	(69.5)	(69.2)	(63.6)	(68.3)	(65.5)	2.9	(69.0)	(67.6)	1.4	(68.9)
43	Business Support	3.12 L6	(40.4)	(41.8)	(40.9)	(41.2)	(43.6)	(2.4)	(41.7)	(49.9)	(8.2)	(52.6)
44	Total	3.12 L7	(142.6)	(142.9)	(135.6)	(139.0)	(138.7)	0.3	(139.1)	(145.9)	(6.8)	(148.1)
	Other											
45	Generation	3.13 L7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
46	Transmission	3.13 L8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
47	Distribution	3.13 L9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	Customer Care	3.13 L10	(29.0)	(63.6)	(54.4)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
49	Business Support	3.13 L11	33.0	(13.3)	(27.2)	(44.4)	(52.7)	(8.3)	(67.8)	(36.3)	31.5	(116.6)
50	Total	3.13 L12	4.0	(76.9)	(81.6)	(44.4)	(52.7)	(8.3)	(67.8)	(36.3)	31.5	(116.6)
	Total Internal Allocation (Prior Approved RRA)											
51	Generation		**(163.5)**	**(158.0)**	**(234.1)**	**(257.6)**	**(250.2)**		**(235.6)**			
52	Transmission		**(406.7)**	**(418.6)**	**(262.4)**	**(253.2)**	**(255.1)**		**(257.8)**			
53	Distribution		**(265.6)**	**(266.8)**	**(240.3)**	**(328.7)**	**(346.6)**		**(326.0)**			
54	Customer Care		**0.0**	**0.0**	**(127.9)**	**(78.7)**	**(75.0)**		**(79.6)**			
55	Capital Infrastructure Project Delivery								**(466.4)**			
56	Generation		**(56.3)**	**(59.1)**								
57	Transmission		**(44.3)**	**(36.3)**								
58	Distribution		**32.5**	**33.8**								
59	Customer Care		**0.0**	**0.0**								
60	Business Support		**(22.6)**	**(28.4)**								
61	Business Support		**(64.5)**	**(39.3)**	**(1,262.1)**	**(440.3)**	**(455.8)**		**(466.4)**			
62	Total		(990.9)	(972.8)	(2,126.9)	(1,358.4)	(1,382.6)		(1,831.8)			

BC Hydro
F22 RRA Compliance

Integrated Planning
Current Operating Costs and Provisions ($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	**Current Operating Costs**	5.0 L38	287.9	286.6	292.5	298.4	297.8	(0.6)	301.1	306.7	5.6	353.0
	Internal Allocations											
2	Generation	Line 15	(107.2)	(105.6)	(99.0)	(102.0)	(98.1)	3.9	(103.4)	(103.5)	(0.1)	(110.2)
3	Transmission	Line 23	(114.5)	(111.7)	(115.7)	(118.5)	(118.4)	0.1	(120.0)	(120.0)	0.0	(139.2)
4	Distribution	Line 31	(63.0)	(66.0)	(74.1)	(73.5)	(76.8)	(3.3)	(72.9)	(77.4)	(4.5)	(98.1)
5	Customer Care							0.0			0.0	
6	Business Support	Line 34	(3.2)	(3.3)	(3.7)	(4.4)	(4.5)	(0.1)	(4.8)	(5.8)	(1.1)	(5.6)
7	Total		(287.9)	(286.6)	(292.5)	(298.4)	(297.8)	0.6	(301.1)	(306.7)	(5.6)	(353.0)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:											
	Generation											
9	Energy Planning & Analytics		0.7	0.7	0.8	1.0	1.0	0.0	1.0	1.2	0.2	1.1
10	Dam Safety	5.1 L2	8.4	8.6	9.7	10.2	9.8	(0.4)	10.3	10.9	0.5	11.4
11	Stations Asset Planning		75.0	78.7	71.8	70.7	69.7	(1.0)	71.5	66.8	(4.7)	74.7
12	Engineering Design		6.7	7.0	7.4	7.9	7.7	(0.2)	8.0	7.6	(0.4)	7.5
13	Engineering Services		1.5	1.7	2.1	2.7	2.6	(0.1)	2.8	3.3	0.6	4.4
14	Business Support		14.9	8.8	7.1	9.5	7.2	(2.2)	9.9	13.7	3.8	11.2
15	Subtotal		107.2	105.6	99.0	102.0	98.1	(3.9)	103.4	103.5	0.1	110.2
	Transmission											
16	Energy Planning & Analytics		0.9	0.9	1.1	1.3	1.3	0.0	1.3	1.6	0.3	1.3
17	Stations Asset Planning		27.5	28.8	26.3	25.9	25.5	(0.4)	26.2	24.4	(1.7)	27.8
18	Line Asset Planning		53.6	57.2	64.1	63.1	65.2	2.1	63.7	66.4	2.7	83.9
19	Interconnections and Shared Assets		5.0	4.3	5.2	5.1	6.4	1.3	5.2	6.4	1.2	7.3
20	Engineering Design		7.4	7.8	8.3	8.8	8.6	(0.2)	8.9	8.5	(0.4)	8.4
21	Engineering Services		1.3	1.5	1.9	2.4	2.3	(0.1)	2.4	2.9	0.5	3.8
22	Business Support		18.8	11.1	8.9	11.9	9.1	(2.8)	12.3	9.7	(2.6)	6.7
23	Subtotal		114.5	111.7	115.7	118.5	118.4	(0.1)	120.0	120.0	(0.0)	139.2
	Distribution											
24	Energy Planning & Analytics		0.9	1.0	1.1	1.3	1.3	0.0	1.3	1.6	0.3	1.4
25	Stations Asset Planning		0.4	0.4	0.4	0.4	0.4	(0.0)	0.4	0.4	(0.0)	0.7
26	Line Asset Planning		53.8	57.5	64.4	63.4	65.5	2.1	64.0	66.7	2.7	83.3
27	Interconnections and Shared Assets		5.2	4.5	5.5	5.3	6.7	1.3	5.4	6.7	1.3	5.8
28	Engineering Design		2.1	2.2	2.3	2.4	2.4	(0.1)	2.5	2.4	(0.1)	2.3
29	Engineering Services		0.3	0.3	0.4	0.5	0.5	(0.0)	0.5	0.6	0.1	0.7
30	Business Support		0.2	0.1	0.1	0.1	0.1	(0.0)	(1.2)	(1.0)	0.3	3.8
31	Subtotal		63.0	66.0	74.1	73.5	76.8	3.3	72.9	77.4	4.5	98.1
	Business Support											
32	Energy Planning & Analytics		3.2	3.3	3.7	4.4	4.5	0.1	4.8	5.8	1.1	5.3
33	Business Unit Support		0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.3
34	Subtotal		3.2	3.3	3.7	4.4	4.5	0.1	4.8	5.8	1.1	5.6

BC Hydro
F22 RRA Compliance

Schedule 3.8
Page 27

Capital Infrastructure Project Delivery
Current Operating Costs and Provisions ($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	**Current Operating Costs**	5.0 L39	116.5	123.4	130.1	120.0	119.5	(0.5)	120.0	119.8	(0.2)	118.7
	Internal Allocations											
2	Generation	Line 16	(47.1)	(50.2)	(52.3)	(53.2)	(52.5)	0.6	(54.4)	(54.2)	0.2	(49.4)
3	Transmission	Line 23	(31.7)	(35.6)	(36.3)	(32.0)	(31.6)	0.5	(30.8)	(30.5)	0.3	(33.4)
4	Distribution	Line 29	(5.6)	(5.3)	(5.7)	(5.6)	(5.5)	0.1	(5.4)	(5.4)	0.0	(6.1)
5	Customer Care							0.0			0.0	
6	Business Support	Line 34	(32.1)	(32.4)	(35.8)	(29.2)	(29.8)	(0.6)	(29.4)	(29.7)	(0.3)	(29.8)
7	Total		(116.5)	(123.4)	(130.1)	(120.0)	(119.5)	0.5	(120.0)	(119.8)	0.2	(118.7)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:											
	Generation											
9	Project Delivery		5.4	5.8	5.7	6.0	5.9	(0.0)	7.5	7.2	(0.3)	6.6
10	Indigenous Relations		2.0	1.7	1.9	1.7	1.7	(0.0)	1.8	1.7	(0.0)	1.9
11	Environment		20.8	21.4	23.0	23.6	23.3	(0.3)	23.7	23.9	0.1	24.3
12	Properties		0.7	0.7	0.8	0.7	0.7	0.0	0.7	0.7	0.0	0.7
13	Business Unit Support		0.3	0.3	0.3	0.3	0.3	(0.0)	0.4	0.3	(0.0)	0.5
	Regulatory Account Recoveries - Operating Costs											
14	First Nation Costs		13.0	15.5	15.7	15.6	15.3	(0.3)	15.2	15.1	(0.0)	15.5
15	Capital Project Investigation	5.0 L26	4.8	4.8	4.8	5.2	5.2	0.0	5.2	5.2	0.0	0.0
16	Subtotal		47.1	50.2	52.3	53.2	52.5	(0.6)	54.4	54.2	(0.2)	49.4
	Transmission											
17	Project Delivery		7.0	7.4	7.3	7.6	7.6	(0.1)	6.9	6.6	(0.3)	8.4
18	Indigenous Relations		2.5	2.1	2.3	2.1	2.1	(0.0)	2.1	2.1	(0.0)	2.3
19	Environment		2.6	2.7	2.9	2.9	2.9	(0.0)	3.0	3.0	0.0	3.4
20	Properties		0.2	0.2	0.2	0.1	0.1	0.0	0.1	0.1	0.0	0.2
21	Business Unit Support		0.1	0.1	0.1	0.1	0.1	(0.0)	0.1	0.1	(0.0)	0.3
	Regulatory Account Recoveries - Operating Costs											
22	First Nation Costs		19.5	23.2	23.6	19.1	18.7	(0.4)	18.5	18.5	(0.1)	18.9
23	Subtotal		31.7	35.6	36.3	32.0	31.6	(0.5)	30.8	30.5	(0.3)	33.4

BC Hydro
F22 RRA Compliance

Schedule 3.8
Page 28

Capital Infrastructure Project Delivery
Current Operating Costs and Provisions ($ million)

			F2017	F2018	F2019	F2020			F2021			F2022
		Reference	Actual	Actual	Actual	Decision	Actual	Diff	Decision	Forecast	Diff	Decision
Line		Column	1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Distribution											
24	Project Delivery		0.3	0.4	0.4	0.4	0.4	(0.0)	0.1	0.1	(0.0)	0.4
25	Indigenous Relations		2.3	2.0	2.2	2.0	1.9	(0.0)	2.0	2.0	(0.0)	2.2
26	Environment		2.8	2.9	3.1	3.1	3.1	(0.0)	3.2	3.2	0.0	3.3
27	Properties		0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.0	0.0
28	Business Unit Support		0.1	0.0	0.1	0.1	0.1	(0.0)	0.1	0.1	(0.0)	0.2
29	Subtotal		5.6	5.3	5.7	5.6	5.5	(0.1)	5.4	5.4	(0.0)	6.1
	Business Support											
30	Indigenous Relations		0.4	0.4	0.4	0.4	0.4	(0.0)	0.4	0.4	(0.0)	0.4
31	Environment		0.1	0.1	0.1	0.1	0.1	(0.0)	0.1	0.1	0.0	0.0
32	Properties		31.3	31.7	35.0	28.4	29.1	0.6	28.6	28.9	0.3	29.4
33	Business Unit Support		0.3	0.2	0.3	0.3	0.3	(0.0)	0.3	0.3	(0.0)	0.0
34	Subtotal		32.1	32.4	35.8	29.2	29.8	0.6	29.4	29.7	0.3	29.8

Operations
Current Operating Costs and Provisions ($ million)

Line	Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	**Current Operating Costs**	5.0 L40	216.5	219.1	226.9	273.6	277.5	3.9	275.3	293.5	18.1	248.5
	Internal Allocations											
2	Generation	Line 16	(51.2)	(48.7)	(51.3)	(58.3)	(56.9)	1.4	(59.0)	(63.1)	(4.1)	(61.9)
3	Transmission	Line 23	(62.4)	(64.9)	(64.5)	(69.3)	(70.3)	(1.0)	(70.2)	(74.9)	(4.7)	(73.6)
4	Distribution	Line 31	(101.5)	(103.6)	(108.4)	(144.6)	(148.4)	(3.8)	(144.7)	(155.5)	(10.8)	(112.9)
5	Customer Care	Line 33	(1.4)	(1.9)	(2.7)	(1.4)	(1.9)	(0.5)	(1.4)	0.0	1.4	0.0
6	Business Support							0.0			0.0	
7	Total		(216.5)	(219.1)	(226.9)	(273.6)	(277.5)	(3.9)	(275.3)	(293.5)	(18.1)	(248.5)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:											
	Generation											
9	Program and Contract Management		**0.2**	**0.2**	**0.2**	**0.2**	**0.3**	0.0	**0.2**	**0.3**	0.0	**0.3**
10	Line Field Operations		**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	0.0	**0.2**	**0.2**	0.0	**0.2**
11	Stations Field Operations		**27.3**	**25.9**	**28.7**	**34.8**	**33.7**	(1.1)	**35.2**	**39.6**	4.4	**37.1**
12	Construction Services		**2.3**	**2.5**	**2.5**	**2.7**	**2.7**	0.0	**2.7**	**3.4**	0.7	**3.0**
13	Generation System Operations	5.3 L6	20.5	19.1	18.8	19.7	19.2	(0.5)	20.0	18.8	(1.2)	19.8
14	T&D System Operations		**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	0.0	**0.4**	**0.4**	(0.0)	**0.6**
15	Business Unit Support		**0.3**	**0.5**	**0.6**	**0.3**	**0.5**	0.1	**0.3**	**0.5**	0.2	**0.8**
16	Subtotal		51.2	48.7	51.3	58.3	56.9	(1.4)	59.0	63.1	4.1	61.9
	Transmission											
17	Program and Contract Management		**2.9**	**2.9**	**3.0**	**3.5**	**4.0**	0.5	**3.5**	**4.0**	0.5	**4.2**
18	Line Field Operations		**4.7**	**4.9**	**4.9**	**5.9**	**6.0**	0.1	**6.0**	**6.4**	0.4	**6.3**
19	Stations Field Operations		**9.5**	**9.0**	**9.9**	**12.0**	**11.7**	(0.4)	**12.2**	**13.7**	1.5	**12.1**
20	Construction Services		**7.1**	**7.8**	**7.7**	**8.3**	**8.3**	0.0	**8.4**	**10.5**	2.1	**9.3**
21	T&D System Operations		**37.9**	**40.0**	**38.3**	**39.4**	**40.0**	0.6	**39.9**	**39.8**	(0.1)	**41.0**
22	Business Unit Support		**0.3**	**0.4**	**0.6**	**0.3**	**0.4**	0.1	**0.3**	**0.5**	0.2	**0.8**
23	Subtotal		62.4	64.9	64.5	69.3	70.3	1.0	70.2	74.9	4.7	73.6
	Distribution											
24	Program and Contract Management		**8.6**	**8.8**	**9.1**	**10.3**	**11.9**	1.6	**10.5**	**12.0**	1.5	**12.8**
25	Line Field Operations		**64.5**	**66.2**	**65.9**	**79.8**	**80.8**	1.0	**80.5**	**86.3**	5.8	**85.8**
26	Stations Field Operations		**4.8**	**4.5**	**5.0**	**6.1**	**5.9**	(0.2)	**6.1**	**6.8**	0.8	**6.6**
27	Distribution Design & Customer Connect	5.3 L4	10.2	10.6	14.9	14.8	15.9	1.1	15.1	16.9	1.8	16.4
28	Construction Services		**2.0**	**2.1**	**2.1**	**2.3**	**2.3**	0.0	**2.3**	**2.9**	0.6	**2.6**
29	Business Unit Support		**0.7**	**0.9**	**1.3**	**0.7**	**0.9**	0.2	**0.7**	**1.1**	0.4	**1.7**
	Regulatory Account Recoveries - Operating Costs											
30	Storm Restoration	5.0 L25	10.8	10.4	10.0	30.6	30.6	0.0	29.5	29.5	0.0	(12.9)
31	Subtotal		101.5	103.6	108.4	144.6	148.4	3.8	144.7	155.5	10.8	112.9
	Customer Care											
32	Business Unit Support (incl. Waneta 2/3)		**1.4**	**1.9**	**2.7**	**1.4**	**1.9**	0.5	**1.4**	**0.0**	(1.4)	**0.0**
33	Subtotal		1.4	1.9	2.7	1.4	1.9	0.5	1.4	0.0	(1.4)	0.0

BC Hydro **Schedule 3.10**
F22 RRA Compliance **Page 30**

Safety
Current Operating Costs and Provisions ($ million)

			F2017	F2018	F2019	F2020			F2021			F2022
		Reference	Actual	Actual	Actual	Decision	Actual	Diff	Decision	Forecast	Diff	Decision
Line	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	**Current Operating Costs**	5.0 L41	56.6	54.2	54.4	57.8	56.4	(1.4)	58.5	69.6	11.1	68.3
	Internal Allocations											
2	Generation							0.0			0.0	
3	Transmission							0.0			0.0	
4	Distribution							0.0			0.0	
5	Customer Care							0.0			0.0	
6	Business Support	Line 15	(56.6)	(54.2)	(54.4)	(57.8)	(56.4)	1.4	(58.5)	(69.6)	(11.1)	(68.3)
7	Total		(56.6)	(54.2)	(54.4)	(57.8)	(56.4)	1.4	(58.5)	(69.6)	(11.1)	(68.3)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:											
	Business Support											
9	Safety System and Assurance	5.4 L1	14.5	14.7	12.1	13.1	12.4	(0.7)	13.3	13.3	0.0	13.3
10	Learning and Development	5.4 L2	25.7	23.2	23.8	25.8	23.2	(2.6)	26.2	25.8	(0.4)	26.3
11	Field Safety Services	5.4 L3	5.7	5.7	6.6	6.6	6.4	(0.1)	6.7	6.9	0.3	7.4
12	Security and Emergency Management	5.4 L4	9.4	9.2	10.5	10.7	12.3	1.6	10.8	19.4	8.6	12.5
13		5.4 L5	0.7	0.9	0.8	1.0	1.4	0.4	1.0	3.7	2.7	8.1
14	Business Unit Support	5.4 L6	0.6	0.6	0.6	0.6	0.6	(0.0)	0.6	0.6	(0.0)	0.8
15	Subtotal		56.6	54.2	54.4	57.8	56.4	(1.4)	58.5	69.6	11.1	68.3

BC Hydro | **Schedule 3.11**
F22 RRA Compliance | **Page 31**

Finance, Technology, Supply Chain
Current Operating Costs and Provisions ($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	**Current Operating Costs**	5.0 L42	253.8	246.7	261.2	262.6	265.1	2.5	264.8	281.4	16.6	299.1
	Internal Allocations											
2	Generation							0.0			0.0	
3	Transmission	Line 10	0.0	0.0	0.0	(0.8)	(0.8)	0.0	(0.8)	(0.8)	0.0	(1.0)
4	Distribution							0.0			0.0	
5	Customer Care							0.0			0.0	
6	Business Support	Line 15	(253.8)	(246.7)	(261.2)	(261.8)	(264.2)	(2.5)	(263.9)	(280.6)	(16.6)	(298.1)
7	Total		(253.8)	(246.7)	(261.2)	(262.6)	(265.1)	(2.5)	(264.8)	(281.4)	(16.6)	(299.1)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function: Transmission											
9	Technology - MODS costs		0.0	0.0	0.0	0.8	0.8	0.0	0.8	0.8	(0.0)	1.0
10	Subtotal		0.0	0.0	0.0	0.8	0.8	0.0	0.8	0.8	(0.0)	1.0
	Business Support											
11	Finance	5.5 L1	28.7	28.7	29.4	31.6	31.6	0.0	32.1	45.8	13.7	51.0
12	Technology (excl. MODS costs)	5.5 L2- Line 9	134.5	128.3	137.1	134.9	137.6	2.6	135.5	138.1	2.5	145.3
13	Supply Chain	5.5 L3	89.9	89.0	94.0	94.5	94.3	(0.2)	95.5	95.9	0.4	101.0
14	Business Unit Support	5.5 L4	0.7	0.7	0.8	0.8	0.8	(0.0)	0.8	0.8	0.0	0.9
15	Subtotal		253.8	246.7	261.2	261.8	264.2	2.5	263.9	280.6	16.6	298.1

BC Hydro **Schedule 3.12**
F22 RRA Compliance **Page 32**

People, Customer, Corporate Affairs
Current Operating Costs and Provisions ($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	**Current Operating Costs**	5.0 L43	142.6	142.9	135.6	139.0	138.7	(0.3)	139.1	145.9	6.8	148.1
	Internal Allocations											
2	Generation							0.0			0.0	
3	Transmission							0.0			0.0	
4	Distribution	Line 11	(32.6)	(31.8)	(31.1)	(29.4)	(29.6)	(0.2)	(28.5)	(28.5)	0.0	(26.6)
5	Customer Care	Line 15	(69.5)	(69.2)	(63.6)	(68.3)	(65.5)	2.9	(69.0)	(67.6)	1.4	(68.9)
6	Business Support	Line 21	(40.4)	(41.8)	(40.9)	(41.2)	(43.6)	(2.4)	(41.7)	(49.9)	(8.2)	(52.6)
7	Total		(142.6)	(142.9)	(135.6)	(139.0)	(138.7)	0.3	(139.1)	(145.9)	(6.8)	(148.1)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:											
	Distribution											
	Regulatory Account Recoveries - Operating Costs											
9	Smart Metering & Infrastructure	5.0 L27	32.6	31.8	31.1	29.4	29.6	0.2	28.5	28.5	0.0	26.6
10	EV Charging Infrastructure	5.0 L35	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Subtotal		32.6	31.8	31.1	29.4	29.6	0.2	28.5	28.5	0.0	26.6
	Customer Care											
12	Customer Services	5.6 L2	68.9	68.7	59.0	62.4	60.5	(1.9)	63.0	61.8	(1.2)	67.8
13	Conservation and Energy Management	5.6 L3	0.6	0.5	0.5	0.6	0.6	(0.0)	0.6	0.4	(0.2)	0.7
14	Customer Crisis Fund	5.6 L12	0.0	0.0	4.1	5.3	4.4	(0.9)	5.3	5.3	(0.0)	0.5
15	Subtotal		69.5	69.2	63.6	68.3	65.5	(2.9)	69.0	67.6	(1.4)	68.9
	Business Support											
16	Human Resources	5.6 L1	21.6	22.1	20.1	21.1	21.0	(0.1)	21.4	21.5	0.1	23.2
17	Communications and Community Engagement	5.6 L4	12.4	13.7	13.7	12.9	12.7	(0.2)	13.0	13.6	0.6	14.2
18	Regulatory and Rates	5.6 L5	5.1	4.5	5.5	5.4	8.1	2.8	5.4	12.8	7.4	13.1
19	Ethics and Merit Office	5.6 L6	0.5	0.6	0.8	1.0	1.0	(0.0)	1.0	1.1	0.1	1.1
20	Business Unit Support	5.6 L7	0.8	0.7	0.7	0.8	0.7	(0.1)	0.8	0.8	0.0	0.9
21	Subtotal		40.4	41.8	40.9	41.2	43.6	2.4	41.7	49.9	8.2	52.6

BC Hydro
F22 RRA Compliance

Schedule 3.13
Page 33

Other
Current Operating Costs and Provisions ($ million)

Line		Reference Column	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	**Current Operating Costs**	5.0 L44	(63.3)	9.0	18.0	(6.1)	(3.2)	2.9	17.3	(14.2)	(31.5)	8.7
2	**Non-Current PEB - Pension**	5.0 L45	59.3	57.9	57.9	51.4	56.8	5.4	51.4	51.4	0.0	114.6
3	**PEB Current Pension Costs**	5.0 L46	0.0	5.7	5.7	(0.9)	(0.9)	0.0	(0.9)	(0.9)	0.0	(6.7)
4	**PEB CPC - F17-F19 RRA Compliance Filing Adjustment**	5.0 L47	0.0	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**Subtotal**		59.3	67.9	63.6	50.5	55.9	8.3	50.5	50.5	(31.5)	107.9
6	**Total**		(4.0)	76.9	81.6	44.4	52.7	8.3	67.8	36.3	(31.5)	116.6
	Internal Allocations											
7	Generation							0.0			0.0	
8	Transmission							0.0			0.0	
9	Distribution							0.0			0.0	
10	Customer Care	Line 17	(29.0)	(63.6)	(54.4)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
11	Business Support	Line 28	33.0	(13.3)	(27.2)	(44.4)	(52.7)	(8.3)	(67.8)	(36.3)	31.5	(116.6)
12	Total		4.0	(76.9)	(81.6)	(44.4)	(52.7)	(8.3)	(67.8)	(36.3)	31.5	(116.6)
13	**Total**		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:											
	Customer Care											
14	Independent Power Producer Capital Leases	5.7 L8	28.2	63.6	54.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Regulatory Account Recoveries											
	- Operating Costs											
15	Home Purchase Offer Plan	5.0 L28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Minimum Reconnection Charge	5.0 L29	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Subtotal		29.0	63.6	54.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Business Support											
18	Office of the General Counsel	5.7 L1	11.1	10.6	11.1	11.7	12.0	0.3	11.8	13.4	1.6	13.0
19	President and Chief Operating Officer	5.7 L2	1.0	0.8	0.9	0.9	0.8	(0.0)	0.9	0.8	(0.0)	0.9
20	Corporate Costs	5.7 L4	13.1	28.4	22.3	28.9	32.7	3.8	29.1	(4.3)	(33.5)	0.5
21	Capitalized Costs	5.7 L5	(281.8)	(283.9)	(284.8)	(285.8)	(287.0)	(1.2)	(286.2)	(285.9)	0.3	(290.4)
22	IFRS Ineligible Capitalized Costs	5.7 L7	102.9	125.3	147.7	170.1	170.1	0.0	192.5	192.5	0.0	214.9
	Regulatory Account Recoveries											
	- Operating Costs											
23	IFRS PP&E	5.0 L33	23.2	26.0	28.2	29.9	29.9	0.0	31.0	31.0	0.0	31.6
24	IFRS Pension	5.0 L34	38.2	38.2	38.2	38.2	38.2	(0.0)	38.2	38.2	0.0	38.2
25	Non-Current PEB - Pension	5.0 L45	59.3	57.9	57.9	51.4	56.8	5.4	51.4	51.4	0.0	114.6
26	PEB Current Pension Costs	5.0 L46	0.0	5.7	5.7	(0.9)	(0.9)	0.0	(0.9)	(0.9)	0.0	(6.7)
27	PEB CPC - F17-F19 RRA Compliance Filing Adjustment	5.0 L47	0.0	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Subtotal		(33.0)	13.3	27.2	44.4	52.7	8.3	67.8	36.3	(31.5)	116.6

BC Hydro
F22 RRA Compliance

Schedule 4.0
Page 34

Cost of Energy

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Sources of Supply (GWh)											
	Heritage Energy											
1	Water Rentals		48,736	47,926	42,341	39,368	40,383	1,015	44,522	47,920	3,398	46,563
2	Natural Gas for Thermal Generation		74	91	191	181	171	(10)	195	175	(20)	222
3	Exchange Net		(253)	599	(155)	(473)	(581)	(108)	(250)	(316)	(66)	(211)
4	Total		48,557	48,616	42,377	39,075	39,972	897	44,467	47,779	3,312	46,574
	Non-Heritage Energy											
5	IPPs and Long-Term Commitments		13,644	14,354	14,248	13,949	14,475	526	15,238	14,467	(771)	15,980
6	Non-Integrated Area		118	115	103	118	106	(11)	120	107	(13)	109
7	Total		13,762	14,469	14,351	14,067	14,581	514	15,358	14,574	(784)	16,089
	Market Energy											
8	Market Electricity Purchases		131	150	2,035	3,633	3,471	(162)	1,326	0	(1,326)	0
9	Surplus Sales		(5,756)	(5,072)	(2,230)	(84)	(182)	(98)	(3,515)	0	3,515	0
10	System Imports									1,485	1,485	1,956
11	System Exports									(8,521)	(8,521)	(6,796)
12	Net Purchases (Sales) from Powerex		138	(557)	647	468	(940)	(1,407)	(279)	0	279	0
13	Total		(5,488)	(5,479)	452	4,017	2,349	(1,667)	(2,467)	(7,036)	(4,569)	(4,840)
14	**Total Sources of Supply**	L4+L7+L13	56,832	57,606	57,181	57,159	56,903	(256)	57,357	55,316	(2,041)	57,823
15	**Less Line Loss and System Use**		(4,937)	(5,504)	(4,768)	(5,200)	(4,972)	228	(5,416)	(4,857)	560	(5,376)
16	**Total Domestic Sales**	14.0 L11	51,895	52,102	52,413	51,958	51,931	(27)	51,940	50,459	(1,481)	52,448
17	**Line Loss as % of Sales**		9.51%	10.56%	9.10%	10.01%	9.57%	(0.43%)	10.43%	9.62%	(0.80%)	10.25%
	Unit Costs ($/MWh)											
18	Water Rentals		7.9	7.5	8.6	8.4	8.2	(0.2)	7.3	6.9	(0.4)	8.1
19	Natural Gas for Thermal Generation		128.9	37.7	40.0	41.8	41.7	(0.1)	43.7	46.9	3.2	53.1
20	IPPs and Long-Term Commitments		88.9	91.4	87.5	92.8	90.8	(2.0)	92.6	96.0	3.4	92.3
21	Non-Integrated Area		211.8	231.0	281.0	259.1	293.8	34.7	250.7	244.1	(6.6)	251.2
22	Market Electricity Purchases		25.8	24.4	61.4	41.5	38.4	(3.1)	32.9	0.0	(32.9)	0.0
23	Surplus Sales		(23.1)	(27.5)	(51.6)	(5.0)	(5.5)	(0.5)	(47.0)	0.0	47.0	0.0
24	System Imports									25.5	25.5	39.4
25	System Exports									24.8	24.8	43.6
26	Total Weighted Cost		29.0	29.5	29.0	35.9	34.9	(1.1)	32.1	31.4	(0.7)	31.8
	Cost of Energy ($ million)											
	Heritage Energy											
27	Water Rentals		387.0	361.6	363.1	329.3	331.6	2.3	323.2	331.0	7.8	375.4
28	Natural Gas for Thermal Generation		9.5	3.4	7.6	7.5	7.1	(0.4)	8.5	8.2	(0.3)	11.8
29	Domestic Transmission - Other		22.5	22.5	22.3	24.5	24.8	0.3	24.4	25.7	1.3	25.5
30	Non-Treaty Storage and Libby Coordination Agreements		(23.3)	(40.6)	(181.9)	15.0	37.7	22.7	(11.7)	(34.2)	(22.4)	(19.0)
31	Remissions and Other		(41.3)	(38.0)	(33.9)	(25.2)	(42.4)	(17.2)	(26.7)	(42.1)	(15.5)	(43.2)
32	Total		354.4	309.0	177.2	351.2	358.8	7.7	317.7	288.6	(29.1)	350.6

BC Hydro
F22 RRA Compliance

Schedule 4.0
Page 35

Cost of Energy

Line	Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Non-Heritage Energy											
33	IPPs and Long-Term Commitments		1,213.1	1,311.6	1,247.2	1,294.7	1,314.0	19.3	1,410.8	1,388.7	(22.1)	1,475.7
34	Non-Integrated Area		25.0	26.5	28.9	30.5	31.3	0.7	30.2	26.1	(4.1)	27.4
35	Gas & Other Transportation		11.7	13.1	9.4	3.7	4.5	0.8	2.5	5.2	2.6	4.9
36	Water Rentals (Waneta 2/3)	15.0 L22	0.0	0.0	2.4	3.5	3.3	(0.2)	3.7	3.2	(0.5)	3.5
37	Total		1,249.7	1,351.1	1,287.9	1,332.4	1,353.1	20.7	1,447.2	1,423.1	(24.0)	1,511.5
	Market Energy											
38	Market Electricity Purchases		3.4	3.7	125.0	150.6	133.1	(17.4)	43.7	0.0	(43.7)	0.0
39	Surplus Sales		(132.8)	(139.4)	(115.0)	(0.4)	(1.0)	(0.6)	(165.1)	0.0	165.1	0.0
40	System Imports									37.8	37.8	77.1
41	System Exports									(211.0)	(211.0)	(296.5)
42	Net Purchases (Sales) from Powerex		2.3	(10.9)	25.0	33.1	(35.2)	(68.3)	6.1	0.0	(6.1)	0.0
43	Domestic Transmission - Export		28.3	25.2	18.5	1.1	2.0	0.9	17.0	45.1	28.1	27.5
44	Total		(98.7)	(121.5)	53.5	184.4	99.0	(85.4)	(98.4)	(128.1)	(29.7)	(191.9)
45	**Total Gross COE**	L32+L37+L44	1,505.5	1,538.7	1,518.7	1,867.9	1,810.9	(57.0)	1,666.5	1,583.7	(82.8)	1,670.1
	Current Cost of Energy											
46	Gross Cost of Energy	Line 45	1,505.5	1,538.7	1,518.7	1,867.9	1,810.9	(57.0)	1,666.5	1,583.7	(82.8)	1,670.1
47	HDA Additions	2.1 L3	31.0	60.4	95.2	0.0	82.4	82.4	0.0	(127.5)	(127.5)	0.0
48	NHDA Additions	2.1 L10+L11	17.2	122.0	118.4	0.0	(100.1)	(100.1)	0.0	221.7	221.7	0.0
49	Deferred Operating HDA	Line 78	(0.1)	0.3	(0.2)	0.0	(1.4)	(1.4)	0.0	(0.7)	(0.7)	0.0
50	Deferred Operating NHDA	Line 92	(8.9)	(35.6)	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	Deferred Amortization NHDA	Line 93	(3.3)	(14.0)	0.0	0.0	0.4	0.4	0.0	(0.2)	(0.2)	0.0
52	Deferred Taxes NHDA	Line 94	(0.4)	(1.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	Deferred Provision NHDA	Line 95	0.0	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	HDA Recoveries	2.1 L5	(4.7)	(13.8)	(51.2)	(272.6)	(280.6)	(7.9)	(229.5)	(229.5)	0.0	0.0
55	NHDA Recoveries	2.1 L13	179.4	196.5	229.1	(43.0)	40.9	83.9	(116.8)	(116.8)	0.0	0.0
56	Load Variance Additions - Revenue	2.1 L23				0.0	0.0	0.0	0.0	(135.5)	(135.5)	0.0
57	Biomass Energy Program Variance Additions - Cost of Energy	2.1 L29				0.0	0.0	0.0	0.0	5.1	5.1	0.0
58	Biomass Energy Program Variance Additions - Revenue	2.1 L30				0.0	0.0	0.0	0.0	1.7	1.7	0.0
59	Customer Crisis Fund Additions - COVID-19 Res. Grants	2.2 L168				0.0	0.0	0.0	0.0	(37.3)	(37.3)	0.0
60	Mining Cust. Pay. Plan Additions - COVID-19 SGS Waivers	2.2 L175				0.0	0.0	0.0	0.0	(6.4)	(6.4)	0.0
61	Electric Vehicle Costs Additions - Cost of Energy					(0.2)	0.0	0.2	(0.3)	(0.3)	0.0	(0.4)
62	Load Variance Recoveries	2.1 L25				82.7	0.0	(82.7)	217.8	217.8	0.0	0.0
63	Biomass Energy Program Variance Recoveries	2.1 L32				0.0	0.0	0.0	0.0	0.0	0.0	0.0
64	**Total Current COE**		1,715.8	1,854.1	1,909.4	1,634.8	1,552.5	(82.3)	1,537.7	1,376.0	(161.7)	1,669.8

BC Hydro | **Schedule 4.0**
F22 RRA Compliance | **Page 36**

Cost of Energy

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Total Current COE by Function											
65	Generation		272.7	238.8	242.8	229.8	293.4	63.7	(16.3)	(24.0)	(7.7)	378.1
66	Distribution		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**
67	Customer Care		1,443.0	1,615.4	1,666.5	1,405.0	1,259.0	(145.9)	1,554.0	1,400.0	(154.0)	1,291.7
68	Total		1,715.8	1,854.1	1,909.4	1,634.8	1,552.5	(82.3)	1,537.7	1,376.0	(161.7)	1,669.8
	Items Subject to HDA											
69	Heritage Energy	Line 32	354.4	309.0	177.2	351.2	358.8	7.7	317.7	288.6	(29.1)	350.6
70	Less: F15-F19 Water Rentals (Waneta 1/3)		**(7.0)**	**(6.5)**	**(6.6)**	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**
71	Market Electricity Purchases	Line 38	3.4	3.7	125.0	150.6	133.1	(17.4)	43.7	0.0	(43.7)	0.0
72	Surplus Sales	Line 39	(132.8)	(139.4)	(115.0)	(0.4)	(1.0)	(0.6)	(165.1)	0.0	165.1	0.0
73	Electric Vehicle Costs Additions	Line 61	0.0	0.0	0.0	(0.2)	0.0	0.2	(0.3)	(0.3)	0.0	**0.0**
74	Domestic Transmission - Export	Line 43	28.3	25.2	18.5	1.1	2.0	0.9	17.0	45.1	28.1	27.5
75	Costs in Operating/Amortization		**12.2**	**12.2**	**12.2**	**12.5**	**12.5**	0.0	**12.5**	**11.9**	(0.7)	**12.5**
76	Notional Water Rentals		**0.8**	**(3.7)**	**4.1**	**3.1**	**(6.1)**	(9.2)	**(1.8)**	**0.0**	1.8	**0.0**
77	Skagit and Ancillary Revenue	14.0 L19 / L39	(13.0)	(11.9)	(29.6)	(36.1)	(29.7)	6.4	(35.9)	(30.2)	5.7	(30.2)
78	Deferred Operating HDA	5.0 L49	(0.1)	0.3	(0.2)	0.0	(1.4)	(1.4)	0.0	(0.7)	(0.7)	0.0
79	Other		**27.9**	**36.3**	**36.2**	**31.5**	**31.0**	(0.5)	**31.2**	**31.2**	0.0	**32.3**
80	Total		274.3	225.1	221.9	513.3	499.3	(14.0)	219.0	345.6	126.5	392.7
81	**Total System Inflow (% of Average)**		**101%**	**98%**	**87%**	**87%**	**93%**	6%	**100%**	**108%**	8%	**100%**
	Items Subject to NHDA											
82	Non-Heritage Cost of Energy	Line 37	1,249.7	1,351.1	1,287.9	1,332.4	1,353.1	20.7	1,447.2	1,423.1	(24.0)	1,511.5
83	Add: F15-F19 Water Rentals (Waneta 1/3)	Line 70	7.0	6.5	6.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
84	Less: Water Rentals (Waneta 2/3)	Line 36	0.0	0.0	(2.4)	(3.5)	(3.3)	0.2	(3.7)	(3.2)	0.5	(3.5)
85	Net Purchases (Sales) from Powerex	Line 42	2.3	(10.9)	25.0	33.1	(35.2)	(68.3)	6.1	0.0	(6.1)	0.0
86	System Imports	Line 40								37.8	37.8	77.1
87	System Exports	Line 41								(211.0)	(211.0)	(296.5)
88	Commodity Risk		**(0.2)**	**(1.0)**	**1.0**	**(1.4)**	**0.8**	2.2	**0.0**	**(9.3)**	(9.3)	**0.0**
89	Notional Water Rental	Line 76	(0.8)	3.7	(4.1)	(3.1)	6.1	9.2	1.8	0.0	(1.8)	0.0
90	Electric Vehicle Costs Additions											**(0.4)**
91	Revenue Variance		**1.3**	**(13.5)**	**50.7**	**0.0**	**139.3**	139.3	**0.0**	**249.0**	249.0	**0.0**
92	Deferred Operating NHDA	5.0 L50	(8.9)	(35.6)	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
93	Deferred Amortization NHDA	7.0 L14	(3.3)	(14.0)	0.0	0.0	0.4	0.4	0.0	(0.2)	(0.2)	0.0
94	Deferred Taxes NHDA	6.0 L20	(0.4)	(1.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
95	Deferred Provision NHDA	5.01 L34	0.0	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
96	Other		**7.9**	**1.2**	**0.3**	**0.0**	**(3.6)**	(3.6)	**0.0**	**(12.5)**	(12.5)	**0.0**
97	Less: IPP subject to Biomass Energy Program Variance					**(35.8)**	**(31.6)**	4.3	**(80.7)**	**(75.5)**	5.1	**(102.4)**
98	Total		1,254.7	1,287.3	1,364.5	1,321.7	1,426.1	104.4	1,370.7	1,398.2	27.6	1,185.8

BC Hydro
F22 RRA Compliance
Cost of Energy

Schedule 4.0
Page 37

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
99	**Biomass Energy Program Cost Def. Acct.**					35.8	31.6	(4.3)	80.7	75.5	(5.1)	102.4
	IPP Summary											
100	IPP Costs in Non-Heritage COE	Line 33	1,213.1	1,311.6	1,247.2	1,294.7	1,314.0	19.3	1,410.8	1,388.7	(22.1)	1,475.7
	Existing Capital Leases											
101	Operating Costs	5.7 L8	28.2	63.6	54.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
102	Taxes	6.0 L10	2.6	4.2	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
103	Amortization	7.0 L11	17.0	29.4	22.8	88.9	88.9	0.0	90.1	90.1	0.0	90.6
104	Finance Charges	8.0 L15	25.1	44.7	42.4	48.4	48.4	0.0	46.1	46.1	0.0	43.5
105	Total		72.9	141.8	122.1	137.4	137.4	0.0	136.1	136.1	0.0	134.1
106	Transfers to Deferral & Regulatory Accounts		(18.4)	(79.4)	(0.5)	0.0	0.4	0.4	0.0	0.1	0.1	0.0
107	Total Costs in Revenue Requirement		1,267.6	1,374.0	1,368.9	1,432.1	1,451.8	19.7	1,546.9	1,524.9	(22.1)	1,609.7
108	Total Payments to IPPs		1,274.7	1,381.7	1,354.9	1,416.6	1,430.9	14.3	1,533.1	1,492.9	(40.2)	1,601.3
109	Difference	L107 - L108	(7.2)	(7.6)	13.9	15.5	20.9	5.4	13.9	32.0	18.2	8.5
	IPP Capital Leases											
	Gross Assets in Service											
110	Opening Balance		388.2	388.2	694.7	694.7	694.7	0.0	1,751.5	1,978.6	227.1	1,978.6
111	Capital Additions		0.0	470.0	0.0	1,751.5	1,978.6	227.1	0.0	0.0	0.0	0.0
112	Retirements & Transfers		0.0	(163.5)	0.0	(694.7)	(694.7)	0.0	0.0	0.0	0.0	0.0
113	Closing Balance		388.2	694.7	694.7	1,751.5	1,978.6	227.1	1,751.5	1,978.6	227.1	1,978.6
	Accumulated Amortization											
114	Opening Balance		186.9	200.6	54.1	77.0	77.0	0.0	592.9	613.0	20.1	702.9
115	Adjustment to Opening Balance		0.0	0.0	0.0	427.0	523.7	96.8	0.0	0.0	0.0	0.0
116	Amortization		13.7	15.4	22.9	88.9	89.3	0.4	90.1	89.9	(0.2)	90.6
117	Retirements & Transfers		0.0	(161.8)	0.0	0.0	(77.0)	(77.0)	0.0	0.0	0.0	0.0
118	Closing Balance		200.6	54.1	77.0	592.9	613.0	20.1	683.0	702.9	19.9	793.5
119	**Net Capital Leases (Year-End)**		187.6	640.6	617.7	1,158.6	1,365.6	207.0	1,068.5	1,275.7	207.2	1,185.1

BC Hydro
F22 RRA Compliance

Operating Costs - Total Company
($ million)

Line	Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Operating Costs by Business Group											
1	Integrated Planning	5.1 L9	287.9	286.6	288.8	292.7	292.5	(0.3)	295.2	300.8	5.6	346.9
2	Capital Infrastructure Project Delivery	5.2 L6	79.2	79.9	85.9	80.1	80.1	0.1	81.1	81.0	(0.1)	84.3
3	Operations	5.3 L9	205.7	208.7	216.9	243.0	246.9	3.9	245.8	263.9	18.1	261.4
4	Safety	5.4 L7	56.6	54.2	54.4	57.8	56.4	(1.4)	58.5	69.6	11.1	68.3
5	Finance, Technology, Supply Chain	5.5 L5	253.8	246.7	261.2	262.6	265.1	2.5	264.8	281.4	16.6	299.1
6	People, Customer, Corporate Affairs	5.6 L8	110.0	111.0	100.4	104.2	104.7	0.4	105.4	112.1	6.8	121.0
7	Other	5.7 L6	(256.6)	(244.0)	(250.5)	(244.3)	(241.4)	2.9	(244.4)	(275.9)	(31.5)	(276.0)
8	**Base Operating Costs**		736.6	743.1	757.2	796.1	804.2	8.1	806.4	833.0	26.6	905.1
9	IFRS Ineligible Capitalized Costs		102.9	125.3	147.7	170.1	170.1	0.0	192.5	192.5	0.0	214.9
10	Independent Power Producer Capital Leases		28.2	63.6	54.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Waneta 2/3		0.0	0.0	3.7	5.7	5.4	(0.3)	5.9	5.9	0.0	6.1
12	Customer Crisis Fund		0.0	0.0	4.1	5.3	4.4	(0.9)	5.3	5.3	(0.0)	0.5
13	**Subtotal**		131.0	188.8	209.8	181.1	179.8	(1.2)	203.6	203.6	(0.0)	221.4
14	**Net Operating Costs**	L8+L13	867.6	931.9	967.1	977.1	984.0	6.9	1,010.0	1,036.6	26.6	1,126.5
	Operating Costs by Resource											
15	Labour (excl Non-Current PEB)		487.8	522.2	544.8	592.2	601.1	8.9	602.5	603.2	0.8	651.7
16	Services - ABSU		48.1	41.9	3.6	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0
17	Services - Other		419.3	434.2	456.8	425.0	412.4	(12.7)	423.6	423.6	0.0	475.9
18	Materials		47.9	48.2	52.9	46.3	54.3	8.0	46.3	49.0	2.7	49.5
19	Buildings & Equipment		67.4	67.2	73.4	51.4	62.7	11.3	51.5	52.1	0.6	51.5
20	Capitalized Overhead		(179.0)	(158.6)	(137.1)	(115.8)	(116.9)	(1.1)	(93.8)	(95.6)	(1.9)	(75.5)
21	External Recoveries		(23.9)	(23.1)	(27.3)	(22.1)	(29.6)	(7.5)	(20.1)	(22.3)	(2.2)	(26.6)
22	F21 Forecast Adjustment							0.0		26.6	26.6	0.0
23	Net Operating Costs		867.6	931.9	967.1	977.1	984.0	6.9	1,010.0	1,036.6	26.6	1,126.5
	Regulatory Account Recoveries - Operating Costs											
24	First Nation Costs		32.4	38.7	39.3	34.7	34.1	(0.6)	33.7	33.6	(0.1)	34.4
25	Storm Restoration		10.8	10.4	10.0	30.6	30.6	0.0	29.5	29.5	0.0	(12.9)
26	Capital Project Investigation		4.8	4.8	4.8	5.2	5.2	0.0	5.2	5.2	0.0	0.0
27	Smart Metering & Infrastructure		32.6	31.8	31.1	29.4	29.6	0.2	28.5	28.5	0.0	26.6
28	Home Purchase Offer Plan		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Minimum Reconnection Charge		0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Non-Current Pension Cost		59.3	57.9	57.9	51.4	56.8	5.4	51.4	51.4	0.0	114.6
31	PEB Current Pension Costs		0.0	5.7	5.7	(0.9)	(0.9)	0.0	(0.9)	(0.9)	0.0	(6.7)
32	PEB CPC - F17-F19 RRA Compliance Filing Adjustment		0.0	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	IFRS PP&E		23.2	26.0	28.2	29.9	29.9	0.0	31.0	31.0	0.0	31.6
34	IFRS Pension		38.2	38.2	38.2	38.2	38.2	(0.0)	38.2	38.2	0.0	38.2
35	Electric Vehicle Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Total		202.3	217.9	215.4	218.7	223.6	4.9	216.7	216.6	(0.1)	225.8
37	**Total Current Operating Costs**	L14+L36	1,069.9	1,149.8	1,182.4	1,195.8	1,207.6	11.8	1,226.7	1,253.2	26.5	1,352.3

BC Hydro | **Schedule 5.0**
F22 RRA Compliance | **Page 39**

Operating Costs - Total Company
($ million)

Line	Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Current Operating Costs by Business Group											
38	Integrated Planning	L1+L11	287.9	286.6	292.5	298.4	297.8	(0.6)	301.1	306.7	5.6	353.0
39	Capital Infrastructure Project Delivery	L2+L24+L26	116.5	123.4	130.1	120.0	119.5	(0.5)	120.0	119.8	(0.2)	118.7
40	Operations	L3+L25	216.5	219.1	226.9	273.6	277.5	3.9	275.3	293.5	18.1	248.5
41	Safety	Line 4	56.6	54.2	54.4	57.8	56.4	(1.4)	58.5	69.6	11.1	68.3
42	Finance, Technology, Supply Chain	Line 5	253.8	246.7	261.2	262.6	265.1	2.5	264.8	281.4	16.6	299.1
43	People, Customer, Corporate Affairs	L6+L12+L27+L35	142.6	142.9	135.6	139.0	138.7	(0.3)	139.1	145.9	6.8	148.1
44	Other	L7+L9+L10+L28+L29+L33 +L34	(63.3)	9.0	18.0	(6.1)	(3.2)	2.9	17.3	(14.2)	(31.5)	8.7
45	Non-Current PEB - Pension	Line 30	59.3	57.9	57.9	51.4	56.8	5.4	51.4	51.4	0.0	114.6
46	PEB Current Pension Costs	Line 31	0.0	5.7	5.7	(0.9)	(0.9)	0.0	(0.9)	(0.9)	0.0	(6.7)
47	PEB CPC - F17-F19 RRA Compliance Filing Adjustment	Line 32	0.0	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	Total		1,069.9	1,149.8	1,182.4	1,195.8	1,207.6	11.8	1,226.7	1,253.2	26.5	1,352.3
	Deferral Account Additions											
49	Transfers to HDA		(0.1)	0.3	(0.2)	0.0	(1.4)	(1.4)	0.0	(0.7)	(0.7)	0.0
50	Transfers to NHDA		(8.9)	(35.6)	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	Total		(9.0)	(35.3)	(0.7)	0.0	(1.4)	(1.4)	0.0	(0.7)	(0.7)	0.0
	Regulatory Account Additions											
52	Demand-Side Management		97.4	82.5	111.3	109.1	95.4	(13.7)	98.8	90.0	(8.7)	97.8
53	First Nations Costs		4.0	2.0	2.3	3.2	2.5	(0.6)	2.4	2.4	(0.1)	2.1
54	Site C Project		0.0	0.3	0.3	0.3	0.3	0.0	0.3	0.3	(0.0)	0.3
55	Storm Restoration		18.6	16.2	18.9	0.0	(7.8)	(7.8)	0.0	0.0	0.0	0.0
56	Smart Metering & Infrastructure		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
57	IFRS Capitalized Overhead		112.0	89.6	67.2	44.8	44.8	0.0	22.4	22.4	0.0	0.0
58	PEB Current Pension Costs		10.1	(2.5)	0.7	0.0	(0.9)	(0.9)	0.0	(5.8)	(5.8)	0.0
59	PEB CPC - F17-F19 RRA Compliance Filing Adjustment		0.0	(10.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
60	Real Property Sales		0.8	1.6	0.6	0.0	0.9	0.9	0.0	0.0	0.0	0.0
61	Customer Crisis Fund		0.0	0.1	(2.7)	(0.3)	(2.7)	(2.4)	(0.3)	0.9	1.2	0.0
62	Electric Vehicle Costs		0.0	0.0	0.0	1.9	0.0	(1.9)	1.7	1.7	0.0	1.8
63	Mining Customer Payment Plan		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.0
64	Total		242.9	179.8	198.7	159.0	132.6	(26.4)	125.4	112.4	(12.9)	102.0
65	**Total Gross Operating Costs**	L14+L51+L64	1,101.5	1,076.4	1,165.1	1,136.1	1,115.2	(20.9)	1,135.4	1,148.4	13.0	1,228.5

BC Hydro
F22 RRA Compliance

Schedule 5.0
Page 40

Operating Costs - Total Company
($ million)

			F2017	F2018	F2019	F2020			F2021			F2022
		Reference	Actual	Actual	Actual	Decision	Actual	Diff	Decision	Forecast	Diff	Decision
Line	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Operating Costs Continuity											
66	**Base Operating Costs**	Line 8	736.6	743.1	757.2	796.1	804.2	8.1	806.4	833.0	26.6	905.1
67	Base Operating Costs Adjustments	Line 13	131.0	188.8	209.8	181.1	179.8	(1.2)	203.6	203.6	(0.0)	221.4
68	**Net Operating Costs**	Line 14	**867.6**	**931.9**	**967.1**	**977.1**	**984.0**	**6.9**	**1,010.0**	**1,036.6**	**26.6**	**1,126.5**
69	Deferral Account Additions and Regulatory Account Additions	L51 + L64	233.9	144.5	198.0	159.0	131.2	(27.8)	125.4	111.8	(13.6)	102.0
70	**Gross Operating Costs**	Line 65	**1,101.5**	**1,076.4**	**1,165.1**	**1,136.1**	**1,115.2**	**(20.9)**	**1,135.4**	**1,148.4**	**13.0**	**1,228.5**
71	Reverse Deferral Account Additions and Regulatory Account Additions	Line 69	(233.9)	(144.5)	(198.0)	(159.0)	(131.2)	27.8	(125.4)	(111.8)	13.6	(102.0)
72	Regulatory Account Recoveries	Line 36	202.3	217.9	215.4	218.7	223.6	4.9	216.7	216.6	(0.1)	225.8
73	**Current Operating Costs**	Line 37	**1,069.9**	**1,149.8**	**1,182.4**	**1,195.8**	**1,207.6**	**11.8**	**1,226.7**	**1,253.2**	**26.5**	**1,352.3**

BC Hydro Schedule 5.01
F22 RRA Compliance Page 41

Provisions & Other - Total Company
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Provisions & Other - By Business Groups											
1	Integrated Planning		72.6	82.6	74.7	67.2	89.5	22.3	71.5	71.1	(0.4)	75.9
2	Capital Infrastructure Project Delivery		(9.0)	(3.9)	(5.4)	1.5	(7.8)	(9.3)	0.3	0.3	0.0	0.1
3	Operations		6.4	15.9	9.7	36.1	33.1	(3.0)	12.3	12.4	0.2	13.4
4	Safety		0.0	0.3	0.7	0.0	6.3	6.3	0.0	0.0	0.0	0.0
5	Finance, Technology, Supply Chain		7.8	7.8	3.9	0.2	4.2	4.0	0.2	0.2	0.0	0.2
6	People, Customer, Corporate Affairs		0.1	0.0	1.2	0.0	0.1	0.1	0.0	0.0	0.0	0.0
7	Other		5.0	12.5	11.2	11.5	3.5	(8.0)	11.2	11.7	0.5	11.9
8	Total		83.0	115.2	95.9	116.4	128.7	12.4	95.4	95.6	0.2	101.4
	Provisions & Other - By Category											
9	Gain/loss on Capital and Intangible Assets		61.8	69.4	60.7	43.9	47.0	3.2	46.8	46.7	(0.0)	50.0
	Gain/Loss on Project Write-offs		0.0	0.0	0.0	0.0	15.3	15.3	0.0	0.0	0.0	0.0
10	Real Property Sales		(10.0)	(10.0)	(10.0)	0.0	(10.0)	(10.0)	0.0	0.0	0.0	0.0
11	Bank Fees and Other Charges		5.1	5.3	5.5	5.5	6.0	0.5	5.6	5.9	0.3	6.0
12	Dismantling Expenses		30.9	35.7	30.6	67.0	67.0	0.0	43.0	43.0	(0.0)	45.5
13	EPA Terminations		0.4	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Other Provisions		(5.1)	10.8	7.0	0.0	3.4	3.4	0.0	0.0	0.0	0.0
15	First Nations Provisions		0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Total		83.0	115.2	95.9	116.4	128.7	12.4	95.4	95.6	0.2	101.4
	Regulatory Account Recoveries											
17	PCB Remediation		18.3	18.9	15.3	22.5	22.5	(0.0)	22.7	22.7	0.0	53.1
18	Asbestos Remediation		24.4	16.6	15.3	9.1	9.1	(0.0)	6.4	6.4	0.0	5.0
19	Dismantling Cost		0.0	0.0	0.0	25.5	25.5	(0.0)	24.6	24.6	0.0	(3.3)
20	Rock Bay Remediation		(3.8)	(3.2)	0.0	(10.8)	(10.8)	(0.0)	(10.4)	(10.4)	0.0	(0.1)
21	Arrow Water Divestiture Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Arrow Water Provision		0.3	1.8	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Rate Smoothing		(201.2)	(326.2)	814.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	Project Write-Off Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.3
25	Total		(162.0)	(292.2)	848.6	46.3	46.3	(0.0)	43.3	43.3	0.0	63.9
26	**Total Current Provisions & Other**	L16 + L25	(79.0)	(177.0)	944.4	162.6	175.0	12.4	138.7	138.9	0.2	165.3
	Current Provisions & Other By Function											
27	Generation		23.9	24.5	25.1	51.1	55.0	3.9	24.8	24.9	0.2	15.1
28	Transmission		47.2	56.8	34.4	33.8	48.7	14.9	37.3	37.8	0.5	62.8
29	Distribution		54.2	48.5	58.6	76.4	78.0	1.6	76.1	75.1	(0.9)	74.2
30	Customer Care		0.4	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Business Unit Support		(204.8)	(310.9)	826.3	1.3	(6.8)	(8.1)	0.6	1.0	0.5	13.2
32	**Total**		(79.0)	(177.0)	944.4	162.6	175.0	12.4	138.7	138.9	0.2	165.3

BC Hydro | **Schedule 5.01**
F22 RRA Compliance | **Page 42**

Provisions & Other - Total Company
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Deferral Account Additions											
33	Transfers to NHDA		0.0	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Total		0.0	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Regulatory Account Additions											
35	First Nations Provisions		(3.3)	0.9	2.4	0.0	0.9	0.9	0.0	1.2	1.2	0.0
36	Environmental Provisions		(28.0)	(4.0)	(7.1)	0.0	51.2	51.2	0.0	96.0	96.0	0.0
37	Arrow Water Provision		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	Smart Metering & Infrastructure DSMD Write-Off		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Real Property Sales		9.0	6.8	9.4	0.0	4.4	4.4	(0.0)	0.0	0.0	0.0
40	Dismantling Expenses		2.9	31.7	11.3	0.0	(8.5)	(8.5)	0.0	5.1	5.1	0.0
41	Project Write-Off Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	Total		(19.5)	35.4	16.0	0.0	48.0	48.0	(0.0)	102.2	102.2	0.0
43	**Total Gross Provisions & Other**	L16 + L34 + L42	63.6	152.3	111.9	116.4	176.8	60.4	95.4	197.9	102.5	101.4
	Provisions & Other Continuity											
44	Provisions & Other	Line 16	83.0	115.2	95.9	116.4	128.7	12.4	95.4	95.6	0.2	101.4
45	Deferral Account Additions and Regulatory Account Additions	L34 + L42	(19.5)	37.1	16.0	0.0	48.0	48.0	(0.0)	102.2	102.2	0.0
46	**Gross Provisions & Other**	Line 43	**63.6**	**152.3**	**111.9**	**116.4**	**176.8**	**60.4**	**95.4**	**197.9**	**102.5**	**101.4**
47	Reverse Deferral Account Additions and Regulatory Account Additions	Line 45	19.5	(37.1)	(16.0)	0.0	(48.0)	(48.0)	0.0	(102.2)	(102.2)	0.0
48												
49	Regulatory Account Recoveries	Line 25	(162.0)	(292.2)	848.6	46.3	46.3	(0.0)	43.3	43.3	0.0	63.9
50	**Current Provisions & Other**	Line 26	**(79.0)**	**(177.0)**	**944.4**	**162.6**	**175.0**	**12.4**	**138.7**	**138.9**	**0.2**	**165.3**

BC Hydro
F22 RRA Compliance

Schedule 5S
Page 43

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Gross Operating Costs Including Regulatory											
1	Labour (excl Non-Current PEB)	L113 + L122	524.9	537.2	573.2	617.0	623.0	6.0	627.2	623.0	(4.3)	678.2
2	Services - ABSU	L114 + L123	48.9	42.3	3.6	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0
3	Services - Other	L115 + L124	502.2	472.7	558.3	513.3	475.8	(37.5)	500.9	492.4	(8.5)	548.7
4	Materials	L116 + L125	48.7	48.8	53.2	46.6	54.2	7.7	46.5	49.3	2.7	49.7
5	Buildings & Equipment	L117 + L126	67.7	67.6	74.0	52.2	63.8	11.6	52.1	52.7	0.6	52.2
6	F21 Forecast Adjustment	L118	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.6	26.6	0.0
			1,192.4	1,168.6	1,262.3	1,229.2	1,216.9	(12.3)	1,226.9	1,243.9	17.1	1,328.8
	Less:											
7	Eligible Capital Overhead	L119 + L130	(67.0)	(69.0)	(69.9)	(71.0)	(72.0)	(1.1)	(71.4)	(73.2)	(1.9)	(75.5)
8	External Recoveries	L120 + L127	(23.9)	(23.1)	(27.3)	(22.1)	(29.6)	(7.5)	(20.1)	(22.3)	(2.2)	(26.6)
9	**Total Gross Operating Costs Including Regulatory Account Additions**	5.0 L65	**1,101.5**	**1,076.4**	**1,165.1**	**1,136.1**	**1,115.2**	**(20.9)**	**1,135.4**	**1,148.4**	**13.0**	**1,226.7**
10	**Total Gross Provision & Other Including Regulatory Account Additions**	5.01 L43	63.6	152.3	111.9	116.4	176.8	60.4	95.4	197.9	102.5	101.4
11	**Total Gross Operating Cost and Provision & Other Including Regulatory Account Additions**		**1,165.1**	**1,228.7**	**1,277.0**	**1,252.5**	**1,292.0**	**39.5**	**1,230.8**	**1,346.3**	**115.5**	**1,328.1**
	Less Operating Costs Reg. Acct. Additions											
	Demand-Side Management											
12	Labour		**(20.8)**	**(20.9)**	**(21.7)**	**(23.3)**	**(22.5)**	0.8	**(23.2)**	**(23.9)**	(0.7)	**(25.3)**
13	Services - ABSU		**(0.8)**	**(0.4)**	**(0.0)**	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**
14	Services - Other		**(75.2)**	**(60.6)**	**(88.8)**	**(84.8)**	**(71.6)**	13.1	**(74.7)**	**(65.3)**	9.4	**(71.6)**
15	Materials		**(0.3)**	**(0.2)**	**(0.1)**	**(0.3)**	**(0.2)**	0.0	**(0.3)**	**(0.3)**	0.0	**(0.2)**
16	Buildings & Equipment		**(0.4)**	**(0.4)**	**(0.6)**	**(0.8)**	**(1.1)**	(0.3)	**(0.6)**	**(0.6)**	0.0	**(0.7)**
17	F17-F19 RRA Compliance Filing Adjustment		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**
	First Nations Costs											
18	Labour		**(1.0)**	**(0.9)**	**(0.9)**	**(0.9)**	**(1.0)**	(0.1)	**(0.8)**	**(0.9)**	(0.1)	**(1.2)**
19	Services - ABSU		**(0.1)**	**(0.0)**	**0.0**	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**
20	Services - Other		**(2.9)**	**(1.1)**	**(1.4)**	**(2.3)**	**(1.5)**	0.8	**(1.6)**	**(1.4)**	0.2	**(0.9)**
21	Materials		**(0.0)**	**(0.0)**	**(0.0)**	**0.0**	**(0.0)**	(0.0)	**0.0**	**0.0**	0.0	**0.0**
22	Buildings & Equipment		**(0.0)**	**(0.0)**	**(0.0)**	**0.0**	**(0.0)**	(0.0)	**0.0**	**0.0**	0.0	**0.0**
	Site C Project											
23	Labour		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**
24	Services - ABSU		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**
25	Services - Other		**0.0**	**(0.3)**	**(0.3)**	**(0.3)**	**(0.3)**	0.0	**(0.3)**	**(0.3)**	0.0	**(0.3)**
26	Materials		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**
27	Buildings & Equipment		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**
	Storm Restoration											
28	Labour		**(4.5)**	**(4.7)**	**(4.7)**	**0.0**	**0.9**	0.9	**0.0**	**0.0**	0.0	**0.0**
29	Services - ABSU		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**
30	Services - Other		**(13.6)**	**(11.1)**	**(14.1)**	**0.0**	**6.6**	6.6	**0.0**	**(0.0)**	(0.0)	**0.0**
31	Materials		**(0.5)**	**(0.3)**	**(0.1)**	**0.0**	**0.3**	0.3	**0.0**	**0.0**	0.0	**0.0**
32	Buildings & Equipment		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**

BC Hydro Schedule 5S
F22 RRA Compliance Page 44

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line		Reference Column	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Gross Operating Costs Including Regulatory											
	Smart Metering & Infrastructure											
33	Labour		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Services - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	External Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Pension Cost											
39	Labour		(10.1)	2.5	(0.7)	0.0	0.9	0.9	0.0	5.8	5.8	0.0
40	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Services - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
43	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Pension Cost - F17-F19 RRA Compliance Filing Adjustment											
44	Labour		0.0	10.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
46	Services - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
47	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Real Property Sales											
49	Labour		(0.4)	(0.5)	(0.3)	0.0	(0.3)	(0.3)	0.0	0.0	0.0	0.0
50	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	Services - Other		(0.4)	(1.1)	(0.3)	0.0	(0.6)	(0.6)	0.0	0.0	0.0	0.0
52	Materials		(0.0)	(0.0)	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
53	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Customer Crisis Fund											
54	Labour		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
55	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
56	Services - Other		0.0	(0.1)	2.7	0.3	2.7	2.4	0.3	(0.9)	(1.2)	(0.0)
57	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
58	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
59	**Electric Vehicle Costs**											
60	Labour		0.0	0.0	0.0	(0.7)	0.0	0.7	(0.7)	(0.7)	0.0	0.0
61	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
62	Services - Other		0.0	0.0	0.0	(1.2)	0.0	1.2	(1.0)	(1.0)	0.0	0.0
63	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
64	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

BC Hydro Schedule 5S
F22 RRA Compliance Page 45

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line		Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
				1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Gross Operating Costs Including Regulatory												
	Mining Customer Payment Plan												
65	Labour			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	Services - ABSU			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
67	Services - Other			0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.6)	(0.6)	0.0
68	Materials			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
69	Buildings & Equipment			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
70	**IFRS Capitalized Overhead**		5.0 L57	(112.0)	(89.6)	(67.2)	(44.8)	(44.8)	0.0	(22.4)	(22.4)	0.0	0.0
71	**Total Operating Costs Reg. Acct. Additions**		5.0 L64	(242.9)	(179.8)	(198.7)	(159.0)	(132.6)	26.4	(125.4)	(112.4)	12.9	(100.2)
	Less Provisions Reg. Acct. Additions												
72	First Nations Provisions		5.01 L35	3.3	(0.9)	(2.4)	0.0	(0.9)	(0.9)	0.0	(1.2)	(1.2)	0.0
73	Environmental Provisions		5.01 L36	28.0	4.0	7.1	0.0	(51.2)	(51.2)	0.0	(96.0)	(96.0)	0.0
74	Arrow Water Provision		5.01 L37	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
75	Smart Metering & Infrastructure DSMD Write-Off		5.01 L38	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
76	Real Property Sales		5.01 L39	(9.0)	(6.8)	(9.4)	0.0	(4.4)	(4.4)	0.0	0.0	(0.0)	0.0
77	Dismantling Cost		5.01 L40	(2.9)	(31.7)	(11.3)	0.0	8.5	8.5	0.0	(5.1)	(5.1)	0.0
78	Project Write-Off Costs		5.01 L41	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
79	**Total Provisions Reg. Acct. Additions**		5.01 L42	19.5	(35.4)	(16.0)	0.0	(48.0)	(48.0)	0.0	(102.2)	(102.2)	0.0
80	**Total Regulatory Account Additions**		L71 + L79 (or 3.0 L22+L28)	(223.4)	(215.3)	(214.8)	(159.0)	(180.6)	(21.6)	(125.4)	(214.7)	(89.3)	(100.2)
	Less Operating Costs Def. Acct. Additions												
	Transfers to HDA												
81	Labour			0.0	(0.1)	(0.1)	0.0	0.1	0.1	0.0	0.0	0.0	0.0
82	Services - Other			0.1	(0.2)	0.3	0.0	1.3	1.3	0.0	0.7	0.7	0.0
83	Materials			(0.0)	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
	Transfers to NHDA												
84	Labour			(0.1)	(0.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
85	Services - Other			9.1	36.1	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
86	Materials			0.0	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Less Provisions Def. Acct. Additions												
	Transfers to NHDA												
87	Provision & Other		5.01 L33		(1.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
88	**Total Deferral Account Additions**		5.0 L51+5.01 L34 (or 3.0 L21+L27)	9.0	33.7	0.7	0.0	1.4	1.4	0.0	0.7	0.7	0.0

BC Hydro
F22 RRA Compliance

Schedule 5S
Page 46

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line	Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Gross Operating Costs Including Regulatory											
	Add Regulatory Account Recoveries											
89	First Nation Costs	5.0 L24	32.4	38.7	39.3	34.7	34.1	(0.6)	33.7	33.6	(0.1)	34.4
90	Storm Restoration	5.0 L25	10.8	10.4	10.0	30.6	30.6	0.0	29.5	29.5	0.0	(12.9)
91	Capital Project Investigation	5.0 L26	4.8	4.8	4.8	5.2	5.2	0.0	5.2	5.2	0.0	0.0
92	Smart Metering & Infrastructure	5.0 L27	32.6	31.8	31.1	29.4	29.6	0.2	28.5	28.5	0.0	26.6
93	Home Purchase Offer Plan	5.0 L28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
94	Minimum Reconnection Charge	5.0 L29	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
95	Non-Current Pension Cost	5.0 L30	59.3	57.9	57.9	51.4	56.8	5.4	51.4	51.4	0.0	114.6
96	PEB Current Pension Costs	5.0 L31	0.0	5.7	5.7	(0.9)	(0.9)	0.0	(0.9)	(0.9)	0.0	(6.7)
97	PEB CPC - F17-F19 RRA Compliance Filing Adjustment	5.0 L32	0.0	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
98	IFRS PP&E	5.0 L33	23.2	26.0	28.2	29.9	29.9	0.0	31.0	31.0	0.0	31.6
99	IFRS Pension	5.0 L34	38.2	38.2	38.2	38.2	38.2	(0.0)	38.2	38.2	0.0	38.2
100	Electric Vehicle Costs	5.0 L35	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
101	**Total Regulatory Account Recoveries (Operating Costs)**	5.0 L36	202.3	217.9	215.4	218.7	223.6	4.9	216.7	216.6	(0.1)	225.8
102	Remediation (PCB)	5.01 L17	18.3	18.9	15.3	22.5	22.5	(0.0)	22.7	22.7	0.0	53.1
103	Remediation (Asbestos)	5.01 L18	24.4	16.6	15.3	9.1	9.1	(0.0)	6.4	6.4	0.0	5.0
104	Dismantling Expense	5.01 L19	0.0	0.0	0.0	25.5	25.5	(0.0)	24.6	24.6	0.0	(3.3)
105	Rock Bay Remediation	5.01 L20	(3.8)	(3.2)	0.0	(10.8)	(10.8)	(0.0)	(10.4)	(10.4)	0.0	(0.1)
106	Arrow Water Divestiture Costs	5.01 L21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
107	Arrow Water Provision	5.01 L22	0.3	1.8	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
108	Rate Smoothing	5.01 L23	(201.2)	(326.2)	814.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
109	Project Write-Off Costs	5.01 L24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.3
110	**Total Regulatory Account Recoveries (Provisions & Other)**	5.01 L25	(162.0)	(292.2)	848.6	46.3	46.3	(0.0)	43.3	43.3	0.0	63.9
111	**Total Regulatory Account Recoveries**	L101 + L110 (or 3.0 L24+L30)	40.3	(74.3)	1,063.9	264.9	269.8	4.9	260.0	259.9	(0.1)	289.7
112	**Total Current Operating Costs & Provisions & Other**	5.0 L48 + 5.01 L26 (or 3.0 L25+L31)	**990.9**	**972.8**	**2,126.9**	**1,358.4**	**1,382.6**	**24.2**	**1,365.4**	**1,392.2**	**26.8**	**1,517.7**
	SUMMARY OF OPERATING COSTS ABOVE											
	Operating Costs Before Deferrals											
113	Labour (excl Non-Current PEB)	5.0 L15	487.8	522.2	544.8	592.2	601.1	8.9	602.5	603.2	0.8	651.7
114	Services - ABSU	5.0 L16	48.1	41.9	3.6	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0
115	Services - Other	5.0 L17	419.3	434.2	456.8	425.0	412.4	(12.7)	423.6	423.6	0.0	475.9
116	Materials	5.0 L18	47.9	48.2	52.9	46.3	54.3	8.0	46.3	49.0	2.7	49.5
117	Buildings & Equipment	5.0 L19	67.4	67.2	73.4	51.4	62.7	11.3	51.5	52.1	0.6	51.5
118	F21 Forecast Adjustment	5.0 L22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.6	26.6	0.0
	Less:											
119	Capital Overhead	5.0 L20	(179.0)	(158.6)	(137.1)	(115.8)	(116.9)	(1.1)	(93.8)	(95.6)	(1.9)	(75.5)
120	External Recoveries	5.0 L21	(23.9)	(23.1)	(27.3)	(22.1)	(29.6)	(7.5)	(20.1)	(22.3)	(2.2)	(26.6)
121	**Total Operating Costs Before Deferrals**	5.0 L23	**867.6**	**931.9**	**967.1**	**977.1**	**984.0**	**6.9**	**1,010.0**	**1,036.6**	**26.6**	**1,126.5**

BC Hydro
F22 RRA Compliance

Schedule 5S
Page 47

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line	Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Gross Operating Costs Including Regulatory Deferred Operating Costs											
122	Labour (excl Non-Current PEB)	-(L12 + L18 + L23 + L28 + L33 + L39 + L44 + L49 + L54 + L60 + L65 + L81 + L84)	37.0	15.0	28.4	24.9	21.9	(2.9)	24.8	19.8	(5.0)	26.5
123	Services - ABSU	-(L13 + L19 + L24 + L29 + L34 + L40 + L45 + L50 + L55 + L61 + L66)	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
124	Services - Other	-(L14 + L20 + L25 + L30 + L35 + L41 + L46 + L51 + L56 + L62 + L67 + L82 + L85)	82.9	38.4	101.5	88.3	63.5	(24.8)	77.4	68.8	(8.6)	72.8
125	Materials	-(L15 + L21 + L26 + L31 + L36 + L42 + L47 + L52 + L57 + L63 + L68 + L83 + L86)	0.8	0.6	0.2	0.3	(0.1)	(0.3)	0.3	0.2	(0.0)	0.2
126	Buildings & Equipment	-(L16 + L22 + L27 + L32 + L37 + L43 + L48 + L53 + L58 + L64 + L69)	0.4	0.4	0.6	0.8	1.1	0.3	0.6	0.6	0.0	0.7
127	External Recoveries	- L38	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
128	F17-F19 RRA Compliance Filing Adjustment	-L17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
129	**Total Deferred Operating Costs**		**121.9**	**54.9**	**130.8**	**114.2**	**86.4**	**(27.8)**	**103.0**	**89.4**	**(13.6)**	**100.2**
130	**IFRS Capitalized Overhead**	5.0 L57	112.0	89.6	67.2	44.8	44.8	0.0	22.4	22.4	0.0	0.0
131	**Total Operating Costs Including Deferrals**	Line 9	**1,101.5**	**1,076.4**	**1,165.1**	**1,136.1**	**1,115.2**	**(20.9)**	**1,135.4**	**1,148.4**	**13.0**	**1,226.7**
132	**Provisions & Other**	Line 10	63.6	152.3	111.9	116.4	176.8	60.4	95.4	197.9	102.5	101.4
133	**Total Gross Operating Cost and Provision & Other Including Deferrals**	Line 11	**1,165.1**	**1,228.7**	**1,277.0**	**1,252.5**	**1,292.0**	**39.5**	**1,230.8**	**1,346.3**	**115.5**	**1,328.1**
	Less											
134	**Deferral Account Additions**	L71 + L88	(233.9)	(146.1)	(198.0)	(159.0)	(131.2)	27.8	(125.4)	(111.8)	13.6	(100.2)
135	**Deferred Provisions & Other**	Line 79	19.5	(35.4)	(16.0)	0.0	(48.0)	(48.0)	0.0	(102.2)	(102.2)	0.0
	Add											
136	**Regulatory Account Recoveries Bf Provisions & Other**	Line 101	202.3	217.9	215.4	218.7	223.6	4.9	216.7	216.6	(0.1)	225.8
137	**Provisions & Other Regulatory Account Recoveries**	Line 110	(162.0)	(292.2)	848.6	46.3	46.3	(0.0)	43.3	43.3	0.0	63.9
138	**Total Current Operating Costs & Provisions & Other**	Line 112	**990.9**	**972.8**	**2,126.9**	**1,358.4**	**1,382.6**	**24.2**	**1,365.4**	**1,392.2**	**26.8**	**1,517.7**
139	**Current Operating Costs**	L121 + L136	**1,069.9**	**1,149.8**	**1,182.4**	**1,195.8**	**1,207.6**	**11.8**	**1,226.7**	**1,253.2**	**26.5**	**1,352.3**

BC Hydro
F22 RRA Compliance

Schedule 5.1
Page 48

Operating Costs - Integrated Planning
($ million)

Line		Column Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Operating Costs by KBU											
1	Energy Planning and Analytics		5.7	5.9	6.7	7.9	8.2	0.2	8.4	10.2	1.9	9.0
2	Dam Safety		8.4	8.6	9.7	10.2	9.8	(0.4)	10.3	10.9	0.5	11.4
3	Stations Asset Planning		102.8	108.0	98.5	97.0	95.6	(1.4)	98.1	91.7	(6.4)	103.2
4	Line Asset Planning		107.4	114.7	128.4	126.6	130.7	4.1	127.7	133.1	5.4	167.2
5	Interconnections and Shared Assets		10.3	8.8	10.7	10.5	13.1	2.6	10.6	13.2	2.5	13.1
6	Engineering Design		16.2	17.0	18.0	19.1	18.7	(0.4)	19.4	18.5	(0.9)	18.2
7	Engineering Services		3.0	3.5	4.4	5.5	5.3	(0.2)	5.6	6.8	1.1	9.0
8	Business Unit Support		34.0	20.1	12.4	15.9	11.1	(4.8)	15.1	16.6	1.5	15.9
9	**Base Operating Costs**		287.9	286.6	288.8	292.7	292.5	(0.3)	295.2	300.8	5.6	346.9
10	IFRS Ineligible Capitalized Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Independent Power Producer Capital Leases		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Waneta 2/3	15.0 L21	0.0	0.0	3.7	5.7	5.4	(0.3)	5.9	5.9	0.0	6.1
13	Customer Crisis Fund		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	**Total Base Operating Costs Adjustment**		0.0	0.0	3.7	5.7	5.4	(0.3)	5.9	5.9	0.0	6.1
15	**Net Operating Costs**		287.9	286.6	292.5	298.4	297.8	(0.6)	301.1	306.7	5.6	353.0
	Operating Costs by Resource											
16	Labour		140.6	143.7	147.7	147.6	154.2	6.7	149.7	153.3	3.6	165.8
17	Services - ABSU		1.5	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Services - Other		129.3	125.1	130.0	149.1	132.4	(16.7)	149.6	148.4	(1.2)	183.0
19	Materials		13.4	13.6	14.5	11.2	13.3	2.1	11.2	14.7	3.5	15.1
20	Buildings & Equipment		14.5	13.9	16.2	2.5	12.4	9.9	2.5	2.0	(0.5)	1.9
21	Capitalized Overhead		0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0
22	External Recoveries		(11.4)	(11.1)	(16.0)	(11.9)	(14.6)	(2.7)	(11.9)	(11.9)	0.0	(12.7)
23	F21 Forecast Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0
24	Total		287.9	286.6	292.5	298.4	297.8	(0.6)	301.1	306.7	5.6	353.0

BC Hydro Schedule 5.2
F22 RRA Compliance Page 49

Operating Costs - Capital Infrastructure Project Delivery
($ million)

Line		F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Reference Column	1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Operating Costs by KBU										
1	Project Delivery	12.7	13.5	13.4	14.0	13.9	(0.1)	14.5	13.9	(0.6)	15.4
2	Indigenous Relations	7.3	6.1	6.7	6.1	6.1	(0.1)	6.3	6.2	(0.1)	6.7
3	Environment	26.2	27.0	29.0	29.8	29.4	(0.4)	30.0	30.1	0.2	31.0
4	Properties	32.2	32.7	36.1	29.3	30.0	0.7	29.5	29.8	0.3	30.3
5	Business Unit Support	0.7	0.7	0.8	0.8	0.8	(0.0)	0.9	0.8	(0.0)	0.9
6	**Base Operating Costs**	79.2	79.9	85.9	80.1	80.1	0.1	81.1	81.0	(0.1)	84.3
7	IFRS Ineligible Capitalized Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Independent Power Producer Capital Leases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Total Base Operating Costs Adjustment**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Net Operating Costs**	79.2	79.9	85.9	80.1	80.1	0.1	81.1	81.0	(0.1)	84.3
	Operating Costs by Resource										
13	Labour	28.7	30.2	31.4	34.1	33.8	(0.3)	35.1	35.8	0.6	38.1
14	Services - ABSU	2.8	2.5	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Services - Other	51.7	49.3	57.2	51.5	52.6	1.1	49.4	52.4	3.0	56.0
16	Materials	1.2	1.2	1.4	1.1	0.4	(0.6)	1.1	0.4	(0.7)	0.4
17	Buildings & Equipment	7.0	7.9	6.6	3.6	3.7	0.1	3.7	3.9	0.2	3.6
18	Capitalized Overhead	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
19	External Recoveries	(12.1)	(11.2)	(10.8)	(10.2)	(10.3)	(0.1)	(8.2)	(10.4)	(2.2)	(13.9)
20	F21 Forecast Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.1)	(1.1)	0.0
21	Total	79.2	79.9	85.9	80.1	80.1	0.1	81.1	81.0	(0.1)	84.3

BC Hydro Schedule 5.3
F22 RRA Compliance Page 50

Operating Costs - Operations
($ million)

Line		F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Reference Column	1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Operating Costs by KBU										
1	Program and Contract Management	11.6	11.9	12.3	14.0	16.2	2.2	14.2	16.2	2.0	17.3
2	Line Field Operations	69.4	71.2	70.9	85.9	87.0	1.1	86.7	92.9	6.2	92.3
3	Stations Field Operations	41.5	39.4	43.6	52.9	51.3	(1.6)	53.5	60.1	6.7	55.8
4	Distribution Design and Customer Connect	10.2	10.6	14.9	14.8	15.9	1.1	15.1	16.9	1.8	16.4
5	Construction Services	11.4	12.4	12.4	13.2	13.2	0.0	13.3	16.7	3.4	14.9
6	Generation System Operations	20.5	19.1	18.8	19.7	19.2	(0.5)	20.0	18.8	(1.2)	19.8
7	Transmission and Distribution System Operations	38.2	40.4	38.7	39.8	40.4	0.6	40.3	40.2	(0.1)	41.6
8	Business Unit Support	2.7	3.8	5.3	2.8	3.7	1.0	2.8	2.1	(0.7)	3.3
9	**Base Operating Costs**	205.7	208.7	216.9	243.0	246.9	3.9	245.8	263.9	18.1	261.4
10	IFRS Ineligible Capitalized Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Independent Power Producer Capital Leases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	**Total Base Operating Costs Adjustment**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	**Net Operating Costs**	205.7	208.7	216.9	243.0	246.9	3.9	245.8	263.9	18.1	261.4
	Operating Costs by Resource										
16	Labour	144.2	147.1	148.2	163.6	167.4	3.8	166.4	168.0	1.6	182.3
17	Services - ABSU	1.8	1.3	0.1	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0
18	Services - Other	43.8	43.2	50.5	62.3	62.4	0.0	62.4	62.8	0.4	62.2
19	Materials	8.9	9.5	10.1	10.2	10.5	0.3	10.2	9.3	(0.9)	9.4
20	Buildings & Equipment	7.0	7.5	7.9	6.8	6.5	(0.3)	6.8	7.7	0.9	7.5
21	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	External Recoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	F21 Forecast Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	16.1	0.0
24	Total	205.7	208.7	216.9	243.0	246.9	3.9	245.8	263.9	18.1	261.4

BC Hydro Schedule 5.4
F22 RRA Compliance Page 51

Operating Costs - Safety
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Operating Costs by KBU											
1	Safety System and Assurance		14.5	14.7	12.1	13.1	12.4	(0.7)	13.3	13.3	0.0	13.3
2	Learning and Development		25.7	23.2	23.8	25.8	23.2	(2.6)	26.2	25.8	(0.4)	26.3
3	Field Safety Services		5.7	5.7	6.6	6.6	6.4	(0.1)	6.7	6.9	0.3	7.4
4	Security and Emergency Management		9.4	9.2	10.5	10.7	12.3	1.6	10.8	19.4	8.6	12.5
5	Reliability Compliance		0.7	0.9	0.8	1.0	1.4	0.4	1.0	3.7	2.7	8.1
6	Business Unit Support		0.6	0.6	0.6	0.6	0.6	(0.0)	0.6	0.6	(0.0)	0.8
7	**Base Operating Costs**		56.6	54.2	54.4	57.8	56.4	(1.4)	58.5	69.6	11.1	68.3
8	IFRS Ineligible Capitalized Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Independent Power Producer Capital Leases		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Waneta 2/3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Customer Crisis Fund		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Total Base Operating Costs Adjustment**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**Net Operating Costs**		56.6	54.2	54.4	57.8	56.4	(1.4)	58.5	69.6	11.1	68.3
	Operating Costs by Resource											
14	Labour		35.9	35.6	35.9	38.7	37.1	(1.6)	39.4	39.9	0.5	45.7
15	Services - ABSU		0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Services - Other		17.8	16.2	16.8	18.0	17.7	(0.3)	18.0	18.9	0.9	21.4
17	Materials		1.8	1.2	1.0	0.8	1.1	0.2	0.8	0.7	(0.1)	0.7
18	Buildings & Equipment		0.7	0.7	0.7	0.3	0.6	0.3	0.3	0.5	0.2	0.5
19	Capitalized Overhead		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	External Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	F21 Forecast Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.7	9.7	0.0
22	Total		56.6	54.2	54.4	57.8	56.4	(1.4)	58.5	69.6	11.1	68.3

BC Hydro
F22 RRA Compliance

Schedule 5.5
Page 52

Operating Costs - Finance, Technology, Supply Chain
($ million)

		F2017	F2018	F2019	F2020			F2021			F2022
	Reference	Actual	Actual	Actual	Decision	Actual	Diff	Decision	Forecast	Diff	Decision
Line	Column	1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Operating Costs by KBU										
1	Finance	28.7	28.7	29.4	31.6	31.6	0.0	32.1	45.8	13.7	51.0
2	Technology	134.5	128.3	137.1	135.8	138.4	2.6	136.4	138.9	2.5	146.3
3	Supply Chain	89.9	89.0	94.0	94.5	94.3	(0.2)	95.5	95.9	0.4	101.0
4	Business Unit Support	0.7	0.7	0.8	0.8	0.8	(0.0)	0.8	0.8	0.0	0.9
5	**Base Operating Costs**	253.8	246.7	261.2	262.6	265.1	2.5	264.8	281.4	16.6	299.1
6	IFRS Ineligible Capitalized Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Independent Power Producer Capital Leases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Total Base Operating Costs Adjustment**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Net Operating Costs**	253.8	246.7	261.2	262.6	265.1	2.5	264.8	281.4	16.6	299.1
	Operating Costs by Resource										
12	Labour	93.8	101.7	107.0	115.6	115.2	(0.5)	117.8	123.8	6.0	132.5
13	Services - ABSU	4.8	3.6	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Services - Other	96.2	85.0	90.7	88.5	89.0	0.5	88.5	96.2	7.7	107.4
15	Materials	22.1	21.3	24.3	21.9	27.2	5.4	21.9	22.2	0.3	22.2
16	Buildings & Equipment	37.3	36.0	39.3	36.6	38.3	1.7	36.6	37.0	0.4	37.0
17	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	External Recoveries	(0.4)	(0.9)	(0.4)	0.0	(4.7)	(4.7)	0.0	0.0	0.0	0.0
19	F21 Forecast Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	2.2	0.0
20	Total	253.8	246.7	261.2	262.6	265.1	2.5	264.8	281.4	16.6	299.1

BC Hydro | **Schedule 5.6**
F22 RRA Compliance | **Page 53**

Operating Costs - People, Customer, Corporate Affairs
($ million)

Line		Reference Column	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Operating Costs by KBU											
1	Human Resources		21.6	22.1	20.1	21.1	21.0	(0.1)	21.4	21.5	0.1	23.2
2	Customer Service		68.9	68.7	59.0	62.4	60.5	(1.9)	63.0	61.8	(1.2)	67.8
3	Conservation and Energy Management		0.6	0.5	0.5	0.6	0.6	(0.0)	0.6	0.4	(0.2)	0.7
4	Communications and Community Engagement		12.4	13.7	13.7	12.9	12.7	(0.2)	13.0	13.6	0.6	14.2
5	Regulatory and Rates		5.1	4.5	5.5	5.4	8.1	2.8	5.4	12.8	7.4	13.1
6	Ethics and Merit Office		0.5	0.6	0.8	1.0	1.0	(0.0)	1.0	1.1	0.1	1.1
7	Business Unit Support		0.8	0.7	0.7	0.8	0.7	(0.1)	0.8	0.8	0.0	0.9
8	**Base Operating Costs**		110.0	111.0	100.4	104.2	104.7	0.4	105.4	112.1	6.8	121.0
9	IFRS Ineligible Capitalized Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Independent Power Producer Capital Leases		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Waneta 2/3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Customer Crisis Fund		0.0	0.0	4.1	5.3	4.4	(0.9)	5.3	5.3	(0.0)	0.5
13	**Total Base Operating Costs Adjustment**		0.0	0.0	4.1	5.3	4.4	(0.9)	5.3	5.3	(0.0)	0.5
14	**Net Operating Costs**		110.0	111.0	104.5	109.5	109.1	(0.5)	110.7	117.4	6.8	121.5
	Operating Costs by Resource											
15	Labour		40.5	44.0	64.6	70.6	70.1	(0.4)	71.7	76.9	5.2	80.4
16	Services - ABSU		37.1	33.1	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Services - Other		31.3	31.9	34.3	36.5	36.2	(0.3)	36.5	38.3	1.8	38.7
18	Materials		0.5	1.2	1.4	1.1	1.7	0.6	1.1	1.6	0.5	1.6
19	Buildings & Equipment		0.7	0.9	1.2	1.4	1.0	(0.4)	1.4	0.8	(0.6)	0.8
20	Capitalized Overhead		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	External Recoveries		0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	F21 Forecast Adjustment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.2)	(0.2)	0.0
23	Total		110.0	111.0	104.5	109.5	109.1	(0.5)	110.7	117.4	6.8	121.5

BC Hydro
F22 RRA Compliance

Schedule 5.7
Page 54

Operating Costs - Other
($ million)

Line	Reference / Column	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Operating Costs by KBU										
1	Office of the General Counsel	11.1	10.6	11.1	11.7	12.0	0.3	11.8	13.4	1.6	13.0
2	Office of the President and Chief Executive Officer	1.0	0.8	0.9	0.9	0.8	(0.0)	0.9	0.8	(0.0)	0.9
3	Site C Project	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Corporate Costs	13.1	28.4	22.3	28.9	32.7	3.8	29.1	(4.3)	(33.5)	0.5
5	Capitalized Costs	(281.8)	(283.9)	(284.8)	(285.8)	(287.0)	(1.2)	(286.2)	(285.9)	0.3	(290.4)
6	**Base Operating Costs**	(256.6)	(244.0)	(250.5)	(244.3)	(241.4)	2.9	(244.4)	(275.9)	(31.5)	(276.0)
7	IFRS Ineligible Capitalized Costs	102.9	125.3	147.7	170.1	170.1	0.0	192.5	192.5	0.0	214.9
8	Independent Power Producer Capital Leases	28.2	63.6	54.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Total Base Operating Costs Adjustment**	131.0	188.8	202.0	170.1	170.1	0.0	192.5	192.5	0.0	214.9
12	**Net Operating Costs**	(125.6)	(55.2)	(48.5)	(74.3)	(71.4)	2.9	(52.0)	(83.5)	(31.5)	(61.1)
	Operating Costs by Resource										
13	Labour	4.1	19.9	9.9	22.1	23.3	1.2	22.4	5.5	(16.8)	6.9
14	Services - ABSU	(0.3)	(0.4)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Services - Other	49.2	83.6	77.3	19.1	22.1	3.0	19.1	6.5	(12.6)	7.2
16	Materials	0.1	0.1	0.2	0.1	0.1	(0.0)	0.1	0.1	(0.0)	0.1
17	Buildings & Equipment	0.2	0.2	1.3	0.2	0.2	(0.0)	0.2	0.2	(0.0)	0.2
18	Capitalized Overhead	(179.0)	(158.6)	(137.1)	(115.8)	(117.0)	(1.2)	(93.8)	(95.6)	(1.9)	(75.5)
19	External Recoveries	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	F21 Forecast Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.2)	(0.2)	0.0
21	Total	(125.6)	(55.2)	(48.5)	(74.3)	(71.4)	2.9	(52.0)	(83.5)	(31.5)	(61.1)

BC Hydro
F22 RRA Compliance

Taxes
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Generation											
1	Grants in Lieu		24.0	24.4	25.6	26.9	26.6	(0.3)	27.9	27.5	(0.5)	28.2
2	School Taxes		16.5	16.5	16.9	17.4	17.7	0.3	18.3	17.7	(0.6)	17.9
3	Total		40.5	40.9	42.5	44.3	44.2	(0.0)	46.3	45.2	(1.1)	46.1
	Transmission											
4	Grants in Lieu		52.1	55.0	60.5	63.6	64.9	1.3	65.7	67.8	2.0	68.6
5	School Taxes		85.8	88.8	91.8	94.0	93.5	(0.5)	98.0	95.4	(2.6)	98.4
6	Total		137.9	143.8	152.3	157.6	158.4	0.8	163.7	163.1	(0.6)	167.0
	Distribution											
7	Grants in Lieu		7.5	7.8	8.2	8.5	8.6	0.0	8.9	8.9	0.1	9.2
8	School Taxes		19.3	19.7	20.0	20.6	20.0	(0.6)	24.0	20.6	(3.4)	22.5
9	Total		26.8	27.5	28.3	29.1	28.6	(0.6)	32.9	29.5	(3.3)	31.7
	Customer Care											
10	IPP Capital Leases		2.6	4.2	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Waneta 2/3											
11	Teck portion of property taxes	15.0 L23	0.0	0.0	0.1	0.6	0.9	0.3	0.6	0.8	0.2	0.8
12	Total		2.6	4.2	2.6	0.6	0.9	0.3	0.6	0.8	0.2	0.8
	Business Support											
13	Grants in Lieu		10.0	10.5	10.9	11.8	11.3	(0.6)	12.2	11.5	(0.7)	12.0
14	School Taxes		5.7	6.1	6.1	6.3	6.4	0.1	6.5	4.6	(1.8)	6.2
15	Total		15.7	16.5	17.0	18.2	17.7	(0.5)	18.7	16.1	(2.6)	18.2
	Total Before Regulatory Accounts											
15	Grants in Lieu	L1+L4+L7+L13	93.6	97.7	105.2	110.8	111.3	0.5	114.8	115.7	0.9	118.0
16	School Taxes	L2+L5+L8+L14	127.3	131.1	134.9	138.3	137.5	(0.8)	146.8	138.3	(8.4)	145.0
17	IPP Capital Leases	L10	2.6	4.2	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Waneta 2/3 Property Taxes	L11	0.0	0.0	0.1	0.6	0.9	0.3	0.6	0.8	0.2	0.8
19	Total		223.5	232.9	242.7	249.8	249.7	(0.1)	262.2	254.8	(7.4)	263.8
	Deferral Account Additions											
20	Transfers to NHDA		(0.4)	(1.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	**Total Gross Taxes**	L19 + L20	223.1	231.1	242.7	249.8	249.7	(0.1)	262.2	254.8	(7.4)	263.8
	Deferral Account Additions											
22	Transfers to NHDA		0.4	1.9	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	**Total Current Taxes**	L21 + L22	223.5	232.9	242.7	249.8	249.7	(0.1)	262.2	254.8	(7.4)	263.8
	Allocation of Current Taxes											
24	Generation	Line 3	40.5	40.9	42.5	44.3	44.2	(0.0)	46.3	45.2	(1.1)	46.1
25	Transmission	Line 6	137.9	143.8	152.3	157.6	158.4	0.8	163.7	163.1	(0.6)	167.0
26	Distribution	Line 9	26.8	27.5	28.3	29.1	28.6	(0.6)	32.9	29.5	(3.3)	31.7
27	Customer Care	Line 12	2.6	4.2	2.6	0.6	0.9	0.3	0.6	0.8	0.2	0.8
28	Business Support	Line 15	15.7	16.5	17.0	18.2	17.7	(0.5)	18.7	16.1	(2.6)	18.2
29	Total		223.5	232.9	242.7	249.8	249.7	(0.1)	262.2	254.8	(7.4)	263.8

BC Hydro
F22 RRA Compliance

Schedule 7.0
Page 56

Depreciation and Amortization
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Amortization of Capital Assets											
1	Generation	12.2 L8:L9	195.9	198.8	234.5	260.9	262.7	1.8	266.8	272.2	5.4	278.5
2	Transmission	12.3 L8:L9	206.8	216.3	224.0	228.4	229.2	0.8	230.8	228.6	(2.2)	233.8
3	Distribution	12.4 L8:L9	184.3	191.4	200.2	206.3	207.3	1.1	216.5	215.3	(1.2)	225.4
4	Business Support	12.1 L8:L9	168.6	185.8	189.8	189.9	186.6	(3.3)	190.4	187.0	(3.4)	191.7
5	Total		755.5	792.2	848.5	885.4	885.8	0.4	904.5	903.1	(1.4)	929.4
	Dismantling Costs											
6	Generation		0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Transmission		2.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Distribution		5.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Business Support		0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Total		8.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	IPP Capital Leases											
11	IPP Capital Leases		17.0	29.4	22.8	88.9	88.9	0.0	90.1	90.1	0.0	90.6
12	Total		17.0	29.4	22.8	88.9	88.9	0.0	90.1	90.1	0.0	90.6
	Other Leases											
13	Amortization		0.0	0.0	0.0	3.4	2.6	(0.8)	3.4	3.7	0.2	3.7
	Deferral Account Additions											
14	Transfers to NHDA		(3.3)	(14.0)	0.0	0.0	0.4	0.4	0.0	(0.2)	(0.2)	0.0
15	Total		(3.3)	(14.0)	0.0	0.0	0.4	0.4	0.0	(0.2)	(0.2)	0.0
16	Less: Electric Vehicle Costs - Ineligible stations					(0.0)		0.0	(0.0)		0.0	
17	**Total Gross Amortization**		777.9	807.6	871.3	977.8	977.7	(0.0)	998.0	996.6	(1.3)	1,023.7
	Deferral Account Additions											
18	Transfers to NHDA		3.3	14.0	0.0	0.0	(0.4)	(0.4)	0.0	0.2	0.2	0.0
	Transfer to Regulatory Account											
19	Amortization on Additions Variance	13.0 L35 - Line20	2.0	(0.7)	(20.4)	0.0	0.4	0.4	0.0	1.6	1.6	0.0
20	Electric Vehicle Costs Additions - New Assets					0.0	0.0	0.0	(0.3)	(0.3)	0.0	(0.3)
21	Electric Vehicle Costs Additions - Existing Assets					(0.2)	0.0	0.2	(0.2)	(0.2)	0.0	(0.2)
22	Transfer to Regulatory Account		2.0	(0.7)	(20.4)	(0.2)	0.4	0.7	(0.5)	1.1	1.6	(0.5)

BC Hydro — **Schedule 7.0**
F22 RRA Compliance — **Page 57**

Depreciation and Amortization
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Regulatory Account Recoveries											
	DSM Amortization											
23	Generation - 90%	(2.2 L5:L6) * 90%	80.2	86.0	89.3	93.0	93.0	(0.0)	96.7	95.8	(0.8)	97.2
24	Transmission - 5%	(2.2 L5:L6) * 5%	8.9	9.6	5.0	5.2	5.2	(0.0)	5.4	5.3	(0.0)	5.4
25	Distribution - 5%	(2.2 L5:L6) * 5%	0.0	0.0	5.0	5.2	5.2	(0.0)	5.4	5.3	(0.0)	5.4
26	Total		89.1	95.6	99.3	103.3	103.3	(0.0)	107.4	106.5	(0.9)	108.0
	FRSR Amortization											
27	Generation	Line 6	(0.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Transmission	Line 7	(2.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Distribution	Line 8	(5.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Business Support	Line 9	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Total		(8.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	**Pre-1996 CIAC Amortization**		0.7	3.2	4.9	5.1	5.1	0.0	5.1	5.1	0.0	5.1
	Capital Additions Regulatory Account											
33	Business Support	2.2 L56	(3.6)	(3.4)	(3.3)	9.7	9.7	(0.0)	9.4	9.4	0.0	(2.1)
34	Total		(3.6)	(3.4)	(3.3)	9.7	9.7	(0.0)	9.4	9.4	0.0	(2.1)
35	**Total Recoveries**		77.5	95.4	100.9	118.1	118.1	(0.0)	121.9	121.0	(0.9)	111.1
36	**Total Current Amortization**		860.7	916.3	951.8	1,095.7	1,095.9	0.3	1,119.4	1,119.0	(0.4)	1,134.2
	Allocation of Current Amortization											
37	Generation	L1+L23	276.0	284.8	323.8	353.9	355.6	1.8	363.5	368.1	4.6	375.7
38	Transmission	L2+L24	215.7	225.8	229.0	233.5	234.4	0.8	236.1	233.9	(2.2)	239.2
39	Distribution	L3+L25+L32	184.9	194.7	210.1	216.5	217.6	1.1	227.0	225.8	(1.2)	235.9
40	Customer Care	L12	17.0	29.4	22.8	88.9	88.9	0.0	90.1	90.1	0.0	90.6
41	Business Support	L4+L13+L16+L19:L21+L33	167.0	181.7	166.1	202.8	199.4	(3.4)	202.7	201.2	(1.5)	192.8
42	Total		860.7	916.3	951.8	1,095.7	1,095.9	0.3	1,119.4	1,119.0	(0.4)	1,134.2

BC Hydro
F22 RRA Compliance

Schedule 8.0
Page 58

Finance Charges
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
1	**Total Gross Finance Charges**	L8 + L20	579.2	805.9	1,192.2	874.9	1,656.8	781.8	743.3	951.5	208.2	555.6
	Regulatory Account Additions											
2	FX Gains/Losses		3.4	(4.2)	4.0	(2.3)	5.3	7.5	(1.5)	(3.0)	(1.4)	(2.6)
3	Deferred IPP Capital Leases (Total Finance Charge Reg. Account Additions)		(5.6)	(26.5)	(0.1)	0.0	0.3	0.3	0.0	0.2	0.2	0.0
4	Accretion - First Nations		17.2	17.2	17.5	17.6	17.6	0.0	18.0	18.0	0.0	18.3
5	Accretion - Environmental		3.9	4.4	5.9	5.5	4.8	(0.7)	4.8	3.8	(1.0)	3.4
6	Accretion - Arrow Water		0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Debt Management		(187.1)	29.3	321.0	100.9	777.3	676.4	0.0	185.0	185.0	0.0
8	Total		(168.0)	20.4	348.4	121.8	805.3	683.5	21.3	204.1	182.8	19.2
9	**Adj. for Regulatory Account Additions**		747.2	785.5	843.8	753.1	851.5	98.3	722.0	747.4	25.4	536.4
	Total Before Regulatory Accounts											
10	Sinking Fund Income	Line 70	(8.2)	(8.3)	(8.7)	(7.8)	(9.1)	(1.2)	(7.7)	(5.2)	2.5	(3.2)
11	Long-Term Debt Costs	Line 86	741.3	774.5	814.9	825.3	824.9	(0.4)	851.5	820.9	(30.6)	772.5
12	Short-Term Debt Costs	Line 95	15.8	20.9	39.5	63.8	47.5	(16.2)	69.6	13.8	(55.8)	13.5
13	Interest Capitalized	Line 105	(81.2)	(108.9)	(130.0)	(181.5)	(175.5)	6.0	(242.6)	(237.7)	4.9	(287.4)
14	Other (Income) / Loss		(12.7)	1.5	28.5	39.2	50.5	11.3	45.1	43.1	(2.0)	47.0
15	IPP Capital Leases		25.1	44.7	42.4	48.4	48.4	0.0	46.1	46.1	0.0	43.5
16	Accretion - Non-Deferrable		1.2	1.1	1.2	1.3	1.3	(0.0)	1.3	1.0	(0.4)	1.0
17	Non-Current PEB		66.0	62.0	55.9	(36.5)	62.1	98.6	(42.2)	64.0	106.2	(52.0)
18	NTL Supplemental Interest Income		0.0	(2.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Other Leases		0.0	0.0	0.0	1.0	1.3	0.2	1.0	1.4	0.4	1.5
20	Total		747.2	785.5	843.8	753.1	851.5	98.3	722.0	747.4	25.4	536.4
21	Total Finance Charge Regulatory Acct. Additions	L16-L3-L20-L22-L25-L26-L27	12.6	25.1	(52.8)	0.0	(0.9)	(0.9)	0.0	76.6	76.6	0.0
22	Site C Project (IFRS 14 IDC impact)		0.0	0.0	0.0	2.0	1.9	(0.1)	2.7	2.1	(0.6)	7.3
	Interest on Regulatory Accounts											
23	Interest on Deferral Accounts	2.1 L41	(41.1)	(26.5)	8.2	15.4	15.9	0.5	4.0	4.8	0.8	0.7
24	Interest on Other Reg Accounts	2.2 L226	(34.2)	(35.2)	(35.7)	(33.1)	(32.6)	0.5	(30.0)	(27.2)	2.8	(25.1)
25	Total		(75.3)	(61.6)	(27.5)	(17.7)	(16.7)	1.0	(26.0)	(22.3)	3.7	(24.5)
	Regulatory Account Recoveries											
26	Amort. of FX Gains/Losses		0.4	(38.3)	(39.2)	0.5	0.5	0.0	(0.5)	0.1	0.6	(0.1)
27	Non-Current Pension		(72.6)	(70.0)	(66.8)	0.0	(98.6)	(98.6)	0.0	(106.2)	(106.2)	0.0
28	Total Finance Charges		(101.8)	(101.8)	(101.8)	10.1	10.1	0.0	10.1	10.1	0.0	(74.1)
29	Debt Management		0.0	0.0	0.0	(12.4)	(12.4)	0.0	(12.4)	(12.4)	0.0	9.1
30	F2017 Correction (RRA Adjustment)		(0.8)	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Total		(174.9)	(209.4)	(207.9)	(1.7)	(100.3)	(98.6)	(2.8)	(108.3)	(105.6)	(65.2)
32	**Total Current Finance Charges**	L3+L20+L21+L22+L25+L31	504.0	513.1	555.6	735.8	735.8	(0.0)	696.0	695.6	(0.4)	454.1

Finance Charges
($ million)

Line	Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Portion of Rate Base											
33	Generation	10.0 L28	41.6%	41.3%	43.9%	46.0%	46.2%	0.2%	45.9%	46.2%	0.3%	45.7%
34	Transmission	10.0 L29	35.5%	35.6%	34.3%	33.2%	33.0%	-0.1%	32.7%	32.6%	(0.1%)	32.7%
35	Distribution	10.0 L30	23.0%	23.1%	21.8%	20.8%	20.8%	-0.1%	21.4%	21.2%	(0.2%)	21.6%
36	Total		100.0%	100.0%	100.0%	100.0%	100.0%	0.0%	100.0%	100.0%	-	100.0%
	Allocation of Current Finance Charges											
37	Generation		209.5	212.0	243.8	338.4	339.9	1.5	319.6	321.4	1.9	207.7
38	Transmission		178.7	182.5	190.5	243.9	243.0	(0.9)	227.6	226.8	(0.8)	148.3
39	Distribution		115.7	118.7	121.3	153.4	152.8	(0.6)	148.8	147.4	(1.4)	98.1
40	Total		504.0	513.1	555.6	735.8	735.8	(0.0)	696.0	695.6	(0.4)	454.1
	Net Debt											
41	Sinking Funds	Line 71	(179.4)	(181.8)	(197.3)	(201.2)	(217.3)	(16.1)	(205.9)	(216.4)	(10.5)	(213.8)
42	Temporary Investments		(48.9)	(41.9)	(83.9)	(10.0)	(115.3)	(105.3)	(10.0)	(10.0)	0.0	(10.0)
43	Long-Term Debt	Line 81	17,185.3	18,311.1	19,437.1	20,777.8	20,942.6	164.8	21,956.8	22,307.7	350.9	23,080.9
44	Short-Term Debt	Line 90	2,838.5	2,053.0	2,944.7	2,950.3	2,743.5	(206.8)	3,139.9	2,914.9	(225.0)	3,241.0
45	Subtotal		19,795.5	20,140.4	22,100.6	23,516.9	23,353.4	(163.4)	24,880.8	24,996.2	115.4	26,098.1
46	WACD Adjustment		180.1	178.8	231.6	180.2	291.1	110.9	188.0	197.3	9.4	197.4
47	End of Year		19,975.6	20,319.2	22,332.2	23,697.0	23,644.5	(52.5)	25,068.8	25,193.6	124.8	26,295.5
48	Mid-Year Balance		19,068.2	20,147.4	21,325.7	23,014.6	22,988.3	(26.3)	24,382.9	24,419.0	36.1	25,740.8
	Weighted Average Cost of Debt (WACD) Rate											
49	Total Gross Finance Charges	Line 1	579.2	805.9	1,192.2	874.9	1,656.8	781.8	743.3	951.5	208.2	555.6
50	WACD Adjustment		177.6	(8.5)	(341.8)	1.8	(796.1)	(797.9)	165.4	(129.7)	(295.1)	239.5
51	Finance Charges for WACD		756.8	797.5	850.4	876.7	860.6	(16.1)	908.7	821.8	(86.9)	795.1
52	Weighted Average Cost of Debt (WACD) Rate		3.97%	3.96%	3.99%	3.81%	3.74%	(0.07%)	3.73%	3.37%	(0.36%)	3.09%
	Increase in Cash											
53	Net Income	9.0 L33	683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
54	Dividend (One Year Lag)	9.0 L4	(584.6)	0.0	(159.0)	(59.0)	(59.0)	0.0	0.0	0.0	0.0	0.0
55	Amortization	7.0 L17	777.9	807.6	871.3	977.8	977.7	(0.0)	998.0	996.6	(1.3)	1,023.7
56	Deferral Account Additions	2.1 L40	63.3	203.7	586.0	3.1	52.2	49.1	3.5	(30.8)	(34.3)	15.5
57	Deferral Account Recoveries	2.1 L42	223.7	233.2	240.6	(403.9)	(403.9)	0.1	(226.9)	(238.3)	(11.5)	0.0
58	Regulatory Account Additions	2.2 L225	(46.8)	(237.7)	(636.4)	(267.7)	(984.2)	(716.5)	(133.1)	(382.7)	(249.6)	(114.7)
59	Regulatory Account Recoveries	2.2 L227	(57.0)	(188.4)	956.9	386.7	287.7	(99.1)	384.6	272.6	(112.0)	335.7
60	First Nations Provisions	2.2 L17	(3.3)	0.9	2.4	0.0	0.9	0.9	0.0	1.2	1.2	0.0
61	Environmental Provisions	2.2 L87	(28.0)	(4.0)	(7.1)	0.0	51.2	51.2	0.0	96.0	96.0	0.0
62	Capital Expenditures	13.0 L12	(2,435.5)	(2,464.9)	(3,816.7)	(2,988.3)	(3,071.4)	(83.1)	(3,104.2)	(3,086.0)	18.2	(2,959.0)
63	Contributions in Aid	11.0 L36	138.4	156.2	185.0	157.8	178.8	21.0	148.5	159.7	11.2	214.2
64	Change in Sinking Funds	Line 69	(4.6)	5.9	(6.8)	3.9	(11.0)	(14.9)	3.1	6.1	3.1	5.7
65	Change in Working Cap & Other		(538.2)	463.1	194.3	131.4	971.9	840.5	(153.9)	(21.5)	132.4	(332.4)
66	F17-F19 RRA Compliance Filing Adj.		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
67	Total		(1,811.2)	(340.3)	(2,017.7)	(1,346.3)	(1,304.2)	42.1	(1,368.6)	(1,536.6)	(168.0)	(1,099.4)

BC Hydro Schedule 8.0
F22 RRA Compliance Page 60

Finance Charges
($ million)

Line		Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
				1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Sinking Funds												
68	Beginning of Year			166.6	179.4	181.8	197.3	197.3	0.0	201.2	217.3	16.1	216.4
69	Change in Sinking Funds			4.6	(5.9)	6.8	(3.9)	11.0	14.9	(3.1)	(6.1)	(3.1)	(5.7)
70	Sinking Fund Income			8.2	8.3	8.7	7.8	9.1	1.2	7.7	5.2	(2.5)	3.2
71	End of Year			179.4	181.8	197.3	201.2	217.3	16.1	205.9	216.4	10.5	213.8
72	Mid-Year Balance			173.0	180.6	189.5	199.2	207.3	8.1	203.5	216.8	13.3	215.1
	Long-Term Debt												
73	Beginning of Year			15,836.6	17,185.3	18,311.1	19,437.1	19,437.1	0.0	20,777.8	20,942.6	164.8	22,307.7
74	Bonds Retired			0.0	(40.0)	(1,286.7)	(175.0)	(175.0)	0.0	(1,099.8)	(1,099.8)	(0.0)	(526.3)
75	Bonds Issued			1,350.0	1,200.0	2,450.0	0.0	1,500.0	1,500.0	0.0	2,200.0	2,200.0	0.0
76	Bonds Planned Issues			0.0	0.0	0.0	1,500.0	0.0	(1,500.0)	2,300.0	0.0	(2,300.0)	1,350.0
77	Revaluation of Foreign $ Debt			19.1	19.7	1.9	(18.4)	78.8	97.2	(16.2)	(21.0)	(4.8)	(29.1)
78	Revaluation to Fair Value			(1.5)	(1.7)	(1.8)	0.0	(2.0)	(2.0)	0.0	0.0	0.0	0.0
79	Premiums/(Discounts) on Issues			(9.7)	(44.0)	(31.8)	40.5	108.1	67.6	0.0	302.2	302.2	0.0
80	Amortization of Issue Costs			(9.2)	(8.2)	(5.6)	(6.4)	(4.4)	2.0	(5.0)	(16.2)	(11.2)	(21.3)
81	End of Year			17,185.3	18,311.1	19,437.1	20,777.8	20,942.6	164.8	21,956.8	22,307.7	350.9	23,080.9
82	Mid-Year Balance			16,511.0	17,748.2	18,874.1	20,107.4	20,189.8	82.4	21,367.3	21,625.1	257.9	22,694.3
83	Interest Rate - Planned Issues						3.46%			3.76%	1.52%		1.91%
84	Debt Costs - Excluding Planned			741.3	774.5	814.9	799.4	824.9	25.6	756.3	820.9	64.6	759.6
85	Debt Costs - Planned Issues			0.0	0.0	0.0	25.9	0.0	(25.9)	95.2	0.0	(95.2)	12.9
86	Total Long-Term Debt Costs			741.3	774.5	814.9	825.3	824.9	(0.4)	851.5	820.9	(30.6)	772.5
	Short-Term Debt												
87	Beginning of Year			2,376.0	2,838.5	2,053.0	2,944.7	2,944.7	0.0	2,950.3	2,743.5	(206.8)	2,914.9
88	Increase in Cash Requirement		Line 67	1,811.2	340.3	2,017.7	1,346.3	1,304.2	(42.1)	1,368.6	1,536.6	168.0	1,099.4
89	Change in Long-Term Debt		L73 - L81	(1,348.7)	(1,125.8)	(1,126.0)	(1,340.7)	(1,505.5)	(164.8)	(1,179.0)	(1,365.2)	(186.2)	(773.2)
90	End of Year			2,838.5	2,053.0	2,944.7	2,950.3	2,743.5	(206.8)	3,139.9	2,914.9	(225.0)	3,241.0
91	Mid-Year Balance			2,607.3	2,445.8	2,498.8	2,947.5	2,844.1	(103.4)	3,045.1	2,829.2	(215.9)	3,074.2
92	Interest Rate						2.35%			2.69%	0.32%		0.39%
93	Debt Costs - Interest			15.8	20.9	39.5	69.3	47.5	(21.8)	81.9	13.8	(68.1)	12.0
94	Debt Costs - Other			0.0	0.0	0.0	(5.6)	0.0	5.6	(12.3)	0.0	12.3	1.5
95	Total Short-Term Debt Costs			15.8	20.9	39.5	63.8	47.5	(16.2)	69.6	13.8	(55.8)	13.5

BC Hydro
F22 RRA Compliance

Schedule 8.0
Page 61

Finance Charges
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Interest During Construction (IDC) Rate											
96	Finance Charges for WACD	Line 51	756.8	797.5	850.4	876.7	860.6	(16.1)	908.7	821.8	(86.9)	795.1
97	Amortization of Debt Management Reg. Acct.	Line 29	0.0	0.0	0.0	12.4	12.4	0.0	12.4	12.4	0.0	(9.1)
98	Finance Charges for IDC		756.8	797.5	850.4	889.1	873.0	(16.1)	921.1	834.2	(86.9)	786.1
99	Net Debt Mid-Year Balance	Line 48	19,068.2	20,147.4	21,325.7	23,014.6	22,988.3	(26.3)	24,382.9	24,419.0	36.1	25,740.8
100	Interest During Construction (IDC) Rate		3.97%	3.96%	3.99%	3.86%	3.80%	(0.07%)	3.78%	3.42%	(0.36%)	3.05%
	Interest Capitalized											
101	Unfinished Construction	13.0 L26	2,936.9	3,859.9	4,430.1	5,347.0	5,463.4	116.3	6,958.5	7,152.3	193.8	8,688.0
102	Less Not Subject to IDC		(891.0)	(1,108.8)	(1,170.1)	(647.5)	(841.9)	(194.5)	(535.5)	(193.6)	342.0	721.7
103	Unfinished Subject to IDC		2,045.9	2,751.1	3,260.0	4,699.6	4,621.4	(78.1)	6,423.0	6,958.7	535.7	9,409.6
104	Interest During Construction (IDC) Rate	Line 100	3.97%	3.96%	3.99%	3.86%	3.80%	(0.07%)	3.78%	3.42%	(0.36%)	3.05%
105	Interest Capitalized		81.2	108.9	130.0	181.5	175.5	(6.0)	242.6	237.7	(4.9)	287.4

BC Hydro
F22 RRA Compliance

Return on Equity
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
Column			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Shareholder's Equity											
1	Retained Earnings - Beginning of Year		4,458.0	4,882.5	5,407.5	4,995.0	4,995.0	0.0	5,706.2	5,698.6	(7.6)	6,389.3
2	Adjustment to Opening Balance				74.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Gross Return on Equity	Line 33	683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
4	Dividend to Province	Line 15	(259.0)	(159.0)	(59.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Other Leases		0.0	0.0	0.0	(0.8)	(1.3)	(0.5)	0.0	0.0	0.0	0.0
6	Retained Earnings - End of Year		4,882.5	5,407.5	4,995.0	5,706.2	5,698.6	(7.6)	6,418.2	6,389.3	(28.9)	7,101.3
7	Accum Other Comp Income		230.0	242.7	(220.7)	23.2	273.5	250.3	(46.8)	(909.1)	(862.3)	(43.7)
8	OCI Deferred (Pension)		(203.2)	(193.6)	173.1	(70.0)	(317.2)	(247.2)	0.0	865.4	865.4	0.0
9	Total Shareholder's Equity		4,909.3	5,456.6	4,947.4	5,659.3	5,654.8	(4.5)	6,371.3	6,345.6	(25.8)	7,057.6
	Dividend to Province											
10	Net Income	Line 3				712.0			712.0	690.7		712.0
11	Distributable Surplus					712.0			712.0	690.7		712.0
12	Maximum Dividend Percentage											
13	Maximum Dividend Amount											
14	Minimum Equity Percentage											
15	Dividend to Province					0.0						
	Capitalization											
16	Net Debt	8.0 L45	19,795.5	20,140.4	22,100.6	23,516.9	23,353.4	(163.4)	24,880.8	24,996.2	115.4	26,098.1
17	Shareholder's Equity	Line 9	4,909.3	5,456.6	4,947.4	5,659.3	5,654.8	(4.5)	6,371.3	6,345.6	(25.8)	7,057.6
18	Total		24,704.8	25,597.0	27,048.0	29,176.2	29,008.3	(167.9)	31,252.1	31,341.8	89.6	33,155.7
	Capital Structure											
19	Net Debt		80.1%	78.7%	81.7%	80.6%	80.5%	(0.1%)	79.6%	79.8%	0.1%	78.7%
20	Equity		19.9%	21.3%	18.3%	19.4%	19.5%	0.1%	20.4%	20.2%	(0.1%)	21.3%
21	Total		100.0%	100.0%	100.0%	100.0%	100.0%	-	100.0%	100.0%	-	100.0%
	Deemed Equity											
22	Rate Base	10.0 L26	19,195.4	19,787.8	22,564.5	22,928.8	22,750.5	(178.3)	23,335.6	23,206.9	(128.7)	23,506.2
23	Pre-1996 Customer Contns	2.2 L40	(91.4)	(88.2)	(83.3)	(78.2)	(78.2)	0.0	(73.1)	(73.1)	0.0	(67.9)
24	Powerex & Powertech Assets		51.6	69.2	63.8	65.5	90.4	24.9	67.3	91.8	24.5	93.1
25	Allowance for Working Capital		250.0	250.0	250.0	250.0	250.0	0.0	250.0	250.0	0.0	250.0
26	Total		19,405.5	20,018.7	22,795.1	23,166.1	23,012.7	(153.4)	23,579.8	23,475.6	(104.2)	23,781.3
27	Deemed Equity Percentage		30.0%	30.0%	30.0%	30.0%	30.0%	0.0%	30.0%	30.0%	0.0%	30.0%
28	Year-End Deemed Equity		5,821.7	6,005.6	6,838.5	6,949.8	6,903.8	(46.0)	7,073.9	7,042.7	(31.3)	7,134.4
29	Mid-Year Deemed Equity		5,732.7	5,913.6	6,422.1	6,894.2	6,871.2	(23.0)	7,011.9	6,973.2	(38.6)	7,088.5
30	Achieved ROE		11.92%	11.57%	(6.67%)		10.26%			9.91%		
31	Allowed ROE / Derived ROE (F18-F21)					10.33%			10.15%			10.04%
32	Return on Equity		683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
33	Gross Return on Equity		683.5	684.0	(428.224)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
34	**Current Return on Equity**		683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0

BC Hydro
F22 RRA Compliance

Schedule 9.0
Page 63

Return on Equity
($ million)

			F2017	F2018	F2019	F2020			F2021			F2022
		Reference	Actual	Actual	Actual	Decision	Actual	Diff	Decision	Forecast	Diff	Decision
Line		Column	1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Portion of Rate Base											
35	Generation	10.0 L28	41.6%	41.3%	43.9%	46.0%	46.2%	0.2%	45.9%	46.2%	0.3%	45.7%
36	Transmission	10.0 L29	35.5%	35.6%	34.3%	33.2%	33.0%	(0.1%)	32.7%	32.6%	(0.1%)	32.7%
37	Distribution	10.0 L30	23.0%	23.1%	21.8%	20.8%	20.8%	(0.1%)	21.4%	21.2%	(0.2%)	21.6%
38	Total		100.0%	100.0%	100.0%	100.0%	100.0%	-	100.0%	100.0%	-	100.0%
	Allocation of ROE											
39	Generation	L34 x L35	284.2	282.6	(187.9)	327.5	325.6	(1.9)	326.9	319.2	(7.8)	325.7
40	Transmission	L34 x L36	242.4	243.2	(146.8)	236.1	232.8	(3.2)	232.9	225.2	(7.7)	232.5
41	Distribution	L34 x L37	157.0	158.2	(93.5)	148.4	146.4	(2.0)	152.2	146.3	(5.9)	153.8
42	Total		683.5	684.0	(428.2)	712.0	704.9	(7.1)	712.0	690.7	(21.3)	712.0
	RSRA Write-off											
43	Generation	L32 x L35			(500.3)			0.0			0.0	
44	Transmission	L32 x L36			(390.9)			0.0			0.0	
45	Distribution	L32 x L37			(249.0)			0.0			0.0	
46	Total		0.0	0.0	(1,140.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0

BC Hydro
F22 RRA Compliance

Schedule 10.0
Page 64

Rate Base
($ million)

Line		Reference Column	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Generation											
1	Net Assets in Service	12.2 L13	6,501.3	6,706.0	8,876.3	8,953.8	8,994.9	41.1	9,168.9	9,159.9	(9.1)	9,149.4
2	Net Contributions	11.0 L10	(2.8)	(2.5)	(2.6)	(2.3)	(2.3)	0.0	(2.1)	(2.0)	0.0	(1.8)
3	90% of Net DSM	2.2 L7 x 90%	824.0	812.2	823.1	828.3	815.9	(12.4)	820.5	801.1	(19.4)	791.9
4	Total		7,322.5	7,515.7	9,696.7	9,779.8	9,808.5	28.7	9,987.4	9,959.0	(28.4)	9,939.5
5	Mid-Year		7,252.1	7,419.1	8,606.2	9,738.3	9,752.6	14.4	9,883.6	9,883.7	0.2	9,963.4
	Transmission											
6	Net Assets in Service	12.3 L12	6,764.0	6,946.3	7,243.3	7,301.7	7,207.2	(94.6)	7,293.2	7,254.5	(38.7)	7,453.6
7	Net Contributions	11.0 L22	(536.3)	(537.5)	(294.6)	(303.7)	(301.4)	2.3	(303.5)	(302.1)	1.5	(305.1)
8	5% of Net DSM	2.2 L7 x 5%	91.6	45.1	45.7	46.0	45.3	(0.7)	45.6	44.5	(1.1)	44.0
9	Total		6,319.3	6,453.9	6,994.5	7,044.0	6,951.1	(92.9)	7,035.3	6,996.9	(38.4)	7,192.5
10	Mid-Year		6,185.8	6,386.6	6,724.2	7,019.2	6,972.8	(46.5)	7,039.6	6,974.0	(65.6)	7,113.9
	Distribution											
11	Net Assets in Service	12.4 L12	5,194.3	5,425.2	5,644.8	5,913.5	5,880.0	(33.5)	6,208.2	6,160.4	(47.8)	6,406.0
12	Less: Electric Vehicle Costs Assets				0.0	(0.2)			(2.4)			
13	Net Contributions	11.0 L33	(1,125.4)	(1,229.4)	(1,364.6)	(1,458.9)	(1,481.5)	(22.6)	(1,549.8)	(1,586.8)	(36.9)	(1,740.4)
14	5% of Net DSM	2.2 L7 x 5%	0.0	45.1	45.7	46.0	45.3	(0.7)	45.6	44.5	(1.1)	44.0
15	Total		4,068.9	4,240.9	4,326.0	4,500.4	4,443.8	(56.8)	4,701.6	4,618.1	(85.8)	4,709.7
16	Mid-Year		4,006.5	4,154.9	4,283.4	4,413.2	4,384.9	(28.3)	4,601.0	4,531.0	(70.0)	4,705.6
	Business Support											
17	Net Assets in Service	12.1 L12	1,484.7	1,577.3	1,547.8	1,604.8	1,547.1	(57.7)	1,611.3	1,632.9	21.5	1,664.5
18	Less: Electric Vehicle Costs Assets				(0.5)	(0.2)			(0.0)			
19	Net Contributions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Total		1,484.7	1,577.3	1,547.3	1,604.6	1,547.1	(57.5)	1,611.3	1,632.9	21.5	1,664.5
21	Mid-Year		1,459.8	1,531.0	1,562.3	1,576.0	1,547.2	(28.8)	1,608.0	1,590.0	(18.0)	1,637.9
	Total											
22	Net Assets in Service	12.0 L13	19,944.3	20,654.8	23,312.2	23,773.9	23,629.1	(144.8)	24,281.7	24,207.6	(74.1)	24,673.5
23	Less: Electric Vehicle Costs Assets				(0.5)	(0.5)	0.0	0.5	(2.4)	0.0	2.4	0.0
24	Net Contributions	11.0 L46	(1,664.5)	(1,769.5)	(1,661.8)	(1,764.9)	(1,785.3)	(20.3)	(1,855.4)	(1,890.9)	(35.5)	(2,047.3)
25	Net DSM	2.2 L7	915.6	902.5	914.5	920.3	906.6	(13.7)	911.7	890.1	(21.5)	879.9
26	Total		19,195.4	19,787.8	22,564.5	22,928.8	22,750.5	(178.3)	23,335.6	23,206.9	(128.7)	23,506.2
27	Mid-Year		18,904.2	19,491.6	21,176.1	22,746.7	22,657.5	(89.2)	23,132.2	22,978.7	(153.5)	23,420.9
	Portion of Rate Base											
28	Generation		41.6%	41.3%	43.9%	46.0%	46.2%	0.2%	45.9%	46.2%	0.3%	45.7%
29	Transmission		35.5%	35.6%	34.3%	33.2%	33.0%	(0.1%)	32.7%	32.6%	(0.1%)	32.7%
30	Distribution		23.0%	23.1%	21.8%	20.8%	20.8%	(0.1%)	21.4%	21.2%	(0.2%)	21.6%
31	Total		100.0%	100.0%	100.0%	100.0%	100.0%	-	100.0%	100.0%	-	100.0%

BC Hydro
F22 RRA Compliance

Contributions
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Contributions in Aid - Generation											
1	Gross Contns - Beginning of Year		9.8	9.5	9.5	9.4	9.4	0.0	9.4	9.4	(0.0)	9.4
2	IFRS Opening Balance Adjustment				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Additions		(0.3)	0.0	0.4	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
4	Retirements & Transfers		0.0	(0.0)	(0.5)	(0.0)	0.0	0.0	(0.0)	(0.0)	0.0	(0.0)
5	Gross Contns - End of Year		9.5	9.5	9.4	9.4	9.4	(0.0)	9.4	9.4	(0.0)	9.4
6	Accum Amort - Beginning of Year		6.4	6.7	7.0	6.8	6.8	0.0	7.0	7.1	0.0	7.3
7	Amortization		0.3	0.3	0.3	0.3	0.3	0.0	0.2	0.3	0.0	0.2
8	Retirements & Transfers		0.0	0.0	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Accum Amort - End of Year		6.7	7.0	6.8	7.0	7.1	0.0	7.3	7.3	0.0	7.6
10	Net Contributions - End of Year		2.8	2.5	2.6	2.3	2.3	(0.0)	2.1	2.0	(0.0)	1.8
	Contributions in Aid - Transmission											
11	Gross Contns - Beginning of Year		638.0	653.7	667.0	415.3	415.3	0.0	438.9	427.9	(11.0)	439.0
12	IFRS Opening Balance Adjustment				(256.6)	0.0	(0.7)	(0.7)	0.0	0.0	0.0	0.0
13	Additions		15.8	15.6	15.8	23.7	17.9	(5.8)	14.8	11.2	(3.6)	14.0
14	Retirements & Transfers		(0.1)	(2.3)	(11.0)	(0.1)	(4.6)	(4.4)	(0.2)	(0.1)	0.0	(0.1)
15	Gross Contns - End of Year		653.7	667.0	415.3	438.9	427.9	(11.0)	453.5	439.0	(14.5)	452.9
16	Accum Amort - Beginning of Year		104.0	117.4	129.5	120.7	120.7	0.0	135.1	126.5	(8.7)	136.9
17	IFRS Opening Balance Adjustment				(14.8)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
18	Amortization		13.5	14.0	14.4	14.4	14.8	0.3	14.8	14.7	(0.1)	10.9
19	Retirements & Transfers		(0.1)	(1.9)	(4.2)	0.0	(4.7)	(4.7)	0.0	0.0	0.0	0.0
20	IFRS amortization reclassification				(4.2)	0.0	(4.3)	(4.3)	0.0	(4.3)	(4.3)	0.0
21	Accum Amort - End of Year		117.4	129.5	120.7	135.1	126.5	(8.7)	150.0	136.9	(13.1)	147.8
22	Net Contributions - End of Year		536.3	537.5	294.6	303.7	301.4	(2.3)	303.5	302.1	(1.5)	305.1
	Contributions in Aid - Distribution											
23	Gross Contns - Beginning of Year		1,700.1	1,817.9	1,948.8	2,114.4	2,114.4	0.0	2,244.2	2,263.5	19.3	2,407.4
24	IFRS Opening Balance Adjustment				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	Additions		122.9	140.6	168.8	134.0	160.9	26.9	133.7	148.5	14.8	200.2
26	Retirements & Transfers		(5.1)	(9.7)	(3.2)	(4.2)	(11.8)	(7.6)	(4.4)	(4.6)	(0.3)	(4.7)
27	Gross Contns - End of Year		1,817.9	1,948.8	2,114.4	2,244.2	2,263.5	19.3	2,373.5	2,407.4	33.8	2,602.8
28	Accum Amort - Beginning of Year		660.8	692.5	719.3	749.8	749.8	0.0	785.3	782.0	(3.4)	820.6
29	Amortization		33.4	35.4	37.9	40.6	40.4	(0.2)	43.5	43.8	0.2	47.0
30	Amortization of Pre-1996 CIAC	2.2 L39	(0.7)	(3.2)	(4.9)	(5.1)	(5.1)	0.0	(5.1)	(5.1)	0.0	(5.1)
31	Retirements & Transfers		(1.1)	(5.3)	(2.5)	0.0	(3.1)	(3.1)	0.0	0.0	0.0	0.0
32	Accum Amort - End of Year		692.5	719.3	749.8	785.3	782.0	(3.4)	823.7	820.6	(3.1)	862.5
33	Net Contributions - End of Year		1,125.4	1,229.4	1,364.6	1,458.9	1,481.5	22.6	1,549.8	1,586.8	36.9	1,740.4

BC Hydro
F22 RRA Compliance

Schedule 11.0
Page 66

Contributions
($ million)

Line		Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
				1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Contributions in Aid - Total												
34	Gross Contns - Beginning of Year			2,347.8	2,481.1	2,625.3	2,539.0	2,539.0	0.0	2,692.5	2,700.8	8.3	2,855.7
35	IFRS Opening Balance Adjustment			0.0	0.0	(256.6)	0.0	(0.7)	(0.7)	0.0	0.0	0.0	0.0
36	Additions			138.4	156.2	185.0	157.8	178.8	21.0	148.5	159.7	11.2	214.2
37	Retirements & Transfers			(5.2)	(12.0)	(14.7)	(4.3)	(16.4)	(12.0)	(4.5)	(4.8)	(0.2)	(4.8)
38	Gross Contns - End of Year			2,481.1	2,625.3	2,539.0	2,692.5	2,700.8	8.3	2,836.4	2,855.7	19.3	3,065.1
39	Accum Amort - Beginning of Year			771.1	816.5	855.8	877.3	877.3	0.0	927.5	915.5	(12.0)	964.8
40	IFRS Opening Balance Adjustment			0.0	0.0	(14.8)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0
41	Amortization			47.3	49.7	52.6	55.3	55.5	0.1	58.6	58.7	0.1	58.2
42	Amortization of Pre-96 CIAC			(0.7)	(3.2)	(4.9)	(5.1)	(5.1)	0.0	(5.1)	(5.1)	0.0	(5.1)
43	Retirements & Transfers			(1.2)	(7.2)	(7.2)	0.0	(7.8)	(7.8)	0.0	0.0	0.0	0.0
44	IFRS amortization reclassification			0.0	0.0	(4.2)	0.0	(4.3)	(4.3)	0.0	(4.3)	(4.3)	0.0
45	Accum Amort - End of Year			816.5	855.8	877.3	927.5	915.5	(12.0)	981.0	964.8	(16.2)	1,017.8
46	Net Contributions - End of Year			1,664.5	1,769.5	1,661.8	1,764.9	1,785.3	20.3	1,855.4	1,890.9	35.5	2,047.3

BC Hydro
F22 RRA Compliance

Schedule 12.0
Page 67

Assets - Total (Excluding DSM and IPP Capital Leases)
($ million)

Line	Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Gross Assets in Service											
1	Opening Balance		22,245.4	23,579.6	25,029.3	24,956.3	24,956.3	0.0	26,303.4	26,123.6	(179.8)	27,605.2
2	Adjustment to Opening Balance		0.0	0.0	(3,509.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L21	1,468.6	1,543.7	3,553.1	1,391.0	1,236.1	(154.9)	1,459.0	1,528.3	69.3	1,445.2
4	Retirements & Transfers		(134.3)	(94.0)	(116.5)	(43.9)	(68.8)	(24.9)	(46.8)	(46.7)	0.0	(50.0)
5	Closing Balance		23,579.6	25,029.3	24,956.3	26,303.4	26,123.6	(179.8)	27,715.7	27,605.2	(110.4)	29,000.5
	Accumulated Amortization											
6	Opening Balance		2,962.7	3,635.3	4,374.6	1,644.1	1,644.1	0.0	2,529.5	2,494.5	(35.0)	3,397.6
7	Adjustment to Opening Balance		0.0	0.0	(3,506.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Amortization on Existing Assets		730.4	711.0	681.1	856.8	857.6	0.8	823.7	823.7	0.0	902.8
9	Amortization on Additions	13.0 L35	25.1	81.2	167.4	28.6	28.2	(0.4)	80.7	79.3	(1.4)	26.6
10	Accelerated Amort on Burrard		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Retirements & Transfers		(82.9)	(53.0)	(72.5)	0.0	(35.4)	(35.4)	0.0	0.0	0.0	0.0
12	Closing Balance		3,635.3	4,374.6	1,644.1	2,529.5	2,494.5	(35.0)	3,434.0	3,397.6	(36.4)	4,327.0
13	**Net Assets in Service (Year-End)**		19,944.3	20,654.8	23,312.2	23,773.9	23,629.1	(144.8)	24,281.7	24,207.6	(74.1)	24,673.5

BC Hydro Schedule 12.1
F22 RRA Compliance Page 68

Assets - Business Support
($ million)

Line	Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Gross Assets in Service											
1	Opening Balance		2,036.1	2,203.6	2,457.2	1,920.1	1,920.1	0.0	2,167.0	2,083.0	(84.0)	2,355.8
2	Adjustment to Opening Balance		0.0	0.0	(675.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L39	222.0	283.5	169.7	252.5	194.4	(58.1)	202.5	278.6	76.1	229.3
4	Retirements & Transfers		(54.6)	(29.8)	(31.5)	(5.5)	(31.5)	(25.9)	(5.6)	(5.8)	(0.2)	(6.0)
5	Closing Balance		2,203.6	2,457.2	1,920.1	2,167.0	2,083.0	(84.0)	2,363.9	2,355.8	(8.1)	2,579.1
	Accumulated Amortization											
6	Opening Balance		601.1	718.9	880.0	372.3	372.3	0.0	562.2	535.9	(26.3)	722.9
7	Adjustment to Opening Balance		0.0	0.0	(673.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Amortization on Existing Assets		159.3	157.7	144.0	174.0	173.4	(0.5)	149.0	148.5	(0.5)	179.6
9	Amortization on Additions	13.0 L44	9.3	28.1	45.8	15.9	13.2	(2.8)	41.4	38.5	(2.9)	12.1
10	Retirements & Transfers		(50.8)	(24.7)	(23.9)	0.0	(23.0)	(23.0)	0.0	0.0	0.0	0.0
11	Closing Balance		718.9	880.0	372.3	562.2	535.9	(26.3)	752.5	722.9	(29.6)	914.6
12	**Net Assets in Service (Year-End)**		1,484.7	1,577.3	1,547.8	1,604.8	1,547.1	(57.7)	1,611.3	1,632.9	21.5	1,664.5

BC Hydro
F22 RRA Compliance

Schedule 12.2
Page 69

Assets - Generation
($ million)

Line	Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Gross Assets in Service											
1	Opening Balance		7,249.3	7,561.3	7,955.0	9,304.7	9,304.7	0.0	9,643.1	9,682.3	39.2	10,119.5
2	Adjustment to Opening Balance		0.0	0.0	(1,032.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L36	342.7	407.2	2,405.8	342.6	372.4	29.9	486.3	441.8	(44.6)	272.4
4	Retirements & Transfers		(30.6)	(13.5)	(23.3)	(4.1)	5.2	9.3	(4.4)	(4.6)	(0.2)	(4.4)
5	Closing Balance		7,561.3	7,955.0	9,304.7	9,643.1	9,682.3	39.2	10,125.0	10,119.5	(5.5)	10,387.5
	Accumulated Amortization											
6	Opening Balance		880.6	1,060.1	1,249.0	428.4	428.4	0.0	689.3	687.4	(1.9)	959.6
7	Adjustment to Opening Balance		0.0	0.0	(1,034.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Amortization on Existing Assets		191.0	182.6	173.8	256.7	257.2	0.5	253.7	257.6	3.9	275.3
9	Amortization on Additions	13.0 L41	4.9	16.2	60.7	4.1	5.5	1.3	13.1	14.6	1.5	3.2
10	Accelerated Amort on Burrard		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Retirements & Transfers		(16.4)	(9.8)	(21.0)	0.0	(3.7)	(3.7)	0.0	0.0	0.0	0.0
12	Closing Balance		1,060.1	1,249.0	428.4	689.3	687.4	(1.9)	956.1	959.6	3.5	1,238.1
13	**Net Assets in Service (Year-End)**		6,501.3	6,706.0	8,876.3	8,953.8	8,994.9	41.1	9,168.9	9,159.9	(9.1)	9,149.4

BC Hydro | **Schedule 12.3**
F22 RRA Compliance | **Page 70**

Assets - Transmission
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Gross Assets in Service											
1	Opening Balance		7,226.1	7,695.0	8,086.0	7,697.4	7,697.4	0.0	7,984.1	7,886.5	(97.7)	8,162.3
2	Adjustment to Opening Balance		0.0	0.0	(900.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L37	482.9	407.6	529.2	293.8	199.7	(94.1)	229.5	283.7	54.2	440.7
4	Retirements & Transfers		(14.0)	(16.6)	(17.9)	(7.0)	(10.6)	(3.6)	(7.3)	(7.8)	(0.5)	(7.7)
5	Closing Balance		7,695.0	8,086.0	7,697.4	7,984.1	7,886.5	(97.7)	8,206.4	8,162.3	(44.1)	8,595.3
	Accumulated Amortization											
6	Opening Balance		730.6	931.0	1,139.7	454.0	454.0	0.0	682.4	679.3	(3.1)	907.9
7	Adjustment to Opening Balance		0.0	0.0	(899.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Amortization on Existing Assets		200.7	195.9	190.7	225.9	227.0	1.2	223.1	222.2	(0.9)	228.7
9	Amortization on Additions	13.0 L42	6.1	20.4	33.3	2.5	2.2	(0.3)	7.7	6.4	(1.2)	5.2
10	Retirements & Transfers		(6.5)	(7.5)	(10.7)	0.0	(4.0)	(4.0)	0.0	0.0	0.0	0.0
11	Closing Balance		931.0	1,139.7	454.0	682.4	679.3	(3.1)	913.2	907.9	(5.3)	1,141.7
12	**Net Assets in Service (Year-End)**		6,764.0	6,946.3	7,243.3	7,301.7	7,207.2	(94.6)	7,293.2	7,254.5	(38.7)	7,453.6

BC Hydro | **Schedule 12.4**
F22 RRA Compliance | **Page 71**

Assets - Distribution
($ million)

Line	Column	Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Gross Assets in Service											
1	Opening Balance		5,733.8	6,119.7	6,531.0	6,034.2	6,034.2	0.0	6,509.1	6,471.9	(37.3)	6,967.6
2	Adjustment to Opening Balance		0.0	0.0	(901.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L38	421.1	445.5	448.4	502.2	469.6	(32.6)	540.7	524.3	(16.4)	502.9
4	Retirements & Transfers		(35.1)	(34.2)	(43.8)	(27.2)	(31.9)	(4.7)	(29.5)	(28.5)	0.9	(31.9)
5	Closing Balance		6,119.7	6,531.0	6,034.2	6,509.1	6,471.9	(37.3)	7,020.4	6,967.6	(52.8)	7,438.6
	Accumulated Amortization											
6	Opening Balance		750.4	925.4	1,105.8	389.4	389.4	0.0	595.6	591.9	(3.8)	807.2
7	Adjustment to Opening Balance		0.0	0.0	(899.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Amortization on Existing Assets		179.5	174.8	172.6	200.3	200.0	(0.3)	198.0	195.5	(2.5)	219.3
9	Amortization on Additions	13.0 L43	4.8	16.6	27.6	6.0	7.4	1.3	18.5	19.9	1.3	6.0
10	Retirements & Transfers		(9.3)	(11.0)	(16.9)	0.0	(4.8)	(4.8)	0.0	0.0	0.0	0.0
11	Closing Balance		925.4	1,105.8	389.4	595.6	591.9	(3.8)	812.2	807.2	(4.9)	1,032.6
12	**Net Assets in Service (Year-End)**		5,194.3	5,425.2	5,644.8	5,913.5	5,880.0	(33.5)	6,208.2	6,160.4	(47.8)	6,406.0

BC Hydro
F22 RRA Compliance

Schedule 13.0
Page 72

Capital Expenditures and Additions
($ million)

Line		Reference Column	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Capital Expenditures											
1	Generation Growth		21.2	10.2	5.5	3.2	2.6	(0.6)	0.0	4.6	4.6	5.0
2	Generation - Waneta 2/3		0.0	0.0	1,218.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Generation Sustaining		563.6	534.0	364.7	341.8	302.5	(39.3)	435.5	346.6	(88.9)	383.4
4	Transmission Growth		247.4	280.5	224.3	185.0	159.6	(25.4)	198.9	101.2	(97.7)	142.9
5	Transmission Sustaining		268.1	218.3	193.0	222.6	223.3	0.7	286.5	270.3	(16.2)	325.6
6	Distribution Growth		226.0	287.6	296.0	299.9	339.7	39.8	284.6	343.2	58.6	306.7
7	Distribution Sustaining		224.5	235.2	206.7	187.6	176.2	(11.4)	176.9	175.9	(1.0)	219.3
8	Site C Project		662.7	704.8	1,116.7	1,530.0	1,619.1	89.1	1,535.5	1,626.0	90.5	1,361.0
9	Technology		76.5	71.2	84.3	95.6	133.0	37.4	56.0	71.2	15.2	69.2
10	Properties		86.6	63.5	48.4	58.9	56.4	(2.5)	55.3	65.1	9.8	75.6
11	Fleet & Other		58.9	59.6	58.3	63.6	59.0	(4.6)	75.1	82.0	6.9	70.3
12	Total		2,435.5	2,464.9	3,816.7	2,988.3	3,071.4	83.1	3,104.2	3,086.0	(18.2)	2,959.0
	Total Capital Additions											
13	Generation		342.7	407.2	1,185.5	314.7	359.5	44.8	296.9	244.3	(52.7)	272.4
14	Generation - Waneta 2/3		0.0	0.0	1,220.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Transmission		482.9	407.6	529.2	293.8	199.7	(94.1)	229.5	283.7	54.2	440.7
16	Distribution		421.1	445.5	448.4	502.2	469.6	(32.6)	540.7	524.3	(16.4)	502.9
17	Site C Project		0.0	0.0	0.0	27.9	12.9	(15.0)	189.4	197.5	8.1	0.0
18	Technology		81.6	97.2	64.1	147.6	93.7	(53.9)	75.5	143.4	67.9	94.3
19	Properties		54.8	126.9	33.0	39.9	44.3	4.4	55.6	60.8	5.2	59.8
20	Fleet & Other		85.6	59.4	72.5	65.0	56.4	(8.6)	71.3	74.4	3.1	75.2
21	Total		1,468.6	1,543.7	3,553.1	1,391.0	1,236.1	(154.9)	1,459.0	1,528.3	69.3	1,445.2
	Unfinished Construction											
22	Beginning of Year		2,460.8	3,412.9	4,306.8	4,553.3	4,553.3	0.0	6,150.7	6,373.4	222.8	7,931.1
23	Adjustments		(14.8)	(27.3)	(17.1)	0.0	(15.2)	(15.2)	0.0	0.0	0.0	0.0
24	Change in Unfinished		966.9	921.2	263.6	1,597.4	1,835.3	237.9	1,645.2	1,557.7	(87.5)	1,513.8
25	End of Year		3,412.9	4,306.8	4,553.3	6,150.7	6,373.4	222.8	7,795.8	7,931.1	135.3	9,444.9
26	Mid-Year Balance		2,936.9	3,859.9	4,430.1	5,352.0	5,463.4	111.4	6,973.2	7,152.3	179.0	8,688.0

BC Hydro | **Schedule 13.0**
F22 RRA Compliance | **Page 73**

Capital Expenditures and Additions
($ million)

Line		F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column	1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Amortization on Additions										
27	Generation	4.9	16.2	41.0	3.9	5.3	1.5	11.4	12.8	1.4	3.2
28	Generation - Waneta 2/3	0.0	0.0	19.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	Transmission	6.1	20.4	33.3	2.5	2.2	(0.3)	7.7	6.4	(1.2)	5.2
30	Distribution	4.8	16.6	27.6	6.0	7.4	1.3	18.5	19.9	1.3	6.0
31	Site C Project	0.0	0.0	0.0	0.3	0.1	(0.2)	1.7	1.8	0.1	0.0
32	Technology	5.9	19.5	29.8	13.6	9.9	(3.7)	34.0	29.6	(4.5)	8.8
33	Properties	0.7	2.8	6.5	0.7	0.7	(0.0)	2.5	2.1	(0.4)	1.0
34	Fleet & Other	2.7	5.9	9.4	1.7	2.6	1.0	4.9	6.9	1.9	2.3
35	Total	25.1	81.2	167.4	28.6	28.2	(0.4)	80.7	79.3	(1.4)	26.6
	Summary of Additions										
36	Generation	342.7	407.2	2,405.8	342.6	372.4	29.9	486.3	441.8	(44.6)	272.4
37	Transmission	482.9	407.6	529.2	293.8	199.7	(94.1)	229.5	283.7	54.2	440.7
38	Distribution	421.1	445.5	448.4	502.2	469.6	(32.6)	540.7	524.3	(16.4)	502.9
39	Business Support	222.0	283.5	169.7	252.5	194.4	(58.1)	202.5	278.6	76.1	229.3
40	Total	1,468.6	1,543.7	3,553.1	1,391.0	1,236.1	(154.9)	1,459.0	1,528.3	69.3	1,445.2
	Summary of Amortization on Additions										
41	Generation	4.9	16.2	60.7	4.1	5.5	1.3	13.1	14.6	1.5	3.2
42	Transmission	6.1	20.4	33.3	2.5	2.2	(0.3)	7.7	6.4	(1.2)	5.2
43	Distribution	4.8	16.6	27.6	6.0	7.4	1.3	18.5	19.9	1.3	6.0
44	Business Support	9.3	28.1	45.8	15.9	13.2	(2.8)	41.4	38.5	(2.9)	12.1
45	Total	25.1	81.2	167.4	28.6	28.2	(0.4)	80.7	79.3	(1.4)	26.6
	Composite Depreciation Rate										
46	Generation				2.45%			2.46%			2.38%
47	Transmission				1.70%			2.31%			2.34%
48	Distribution				2.40%			2.40%			2.40%
49	Site C Project				1.95%			1.27%			0.00%
50	Technology				18.38%			18.22%			18.68%
51	Properties				3.59%			3.73%			3.49%
52	Fleet & Other				5.08%			4.55%			6.05%

BC Hydro
F22 RRA Compliance

Schedule 14.0
Page 74

Domestic Energy Sales and Revenue

Line		Reference Column	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Domestic Energy Sales (GWh)											
1	Residential		18,068	18,150	18,000	17,751	17,993	242	17,927	18,765	837	18,856
2	Light Industrial and Commercial		18,968	18,874	19,007	18,631	18,692	60	18,744	17,908	(836)	18,909
3	Large Industrial		13,176	13,433	13,874	13,527	13,383	(145)	13,203	12,033	(1,170)	12,982
4	Irrigation		80	79	79	97	72	(25)	99	73	(27)	79
5	Street Lighting		232	229	225	288	212	(76)	291	223	(68)	213
6	New Westminster & Tongass		464	466	463	585	465	(120)	591	481	(110)	497
7	Fortis		589	551	435	683	586	(97)	695	667	(28)	602
8	Seattle City Light		318	312	309	389	307	(82)	388	310	(78)	310
9	Liquefied Natural Gas		0	6	22	6	16	9	0	0	0	0
10	Other					0	205	205	0	0	0	0
11	Total		51,895	52,102	52,413	51,958	51,931	(27)	51,940	50,459	(1,481)	52,448
	Domestic Revenues ($ million)											
12	Residential		1,916.2	1,996.8	2,025.2	2,149.5	2,168.8	19.4	2,140.4	2,182.5	42.1	2,234.0
13	Light Industrial and Commercial		1,714.7	1,770.6	1,832.3	1,929.4	1,942.0	12.6	1,905.9	1,835.0	(70.9)	1,954.1
14	Large Industrial		732.6	771.2	829.6	875.7	848.4	(27.2)	852.2	731.1	(121.1)	842.3
15	Irrigation		6.0	5.4	6.3	7.9	6.4	(1.5)	7.8	6.9	(0.9)	6.9
16	Street Lighting		39.2	40.6	41.1	56.0	40.2	(15.8)	55.9	43.0	(12.9)	40.2
17	New Westminster & Tongass		27.7	28.9	29.7	40.2	31.8	(8.4)	39.9	31.5	(8.4)	33.6
18	Fortis		36.2	35.6	31.0	49.5	41.0	(8.5)	49.4	44.3	(5.0)	41.1
19	Seattle City Light		13.0	11.9	29.6	36.1	29.7	(6.4)	35.9	30.2	(5.7)	30.2
20	Liquefied Natural Gas		0.4	1.3	1.8	0.5	1.3	0.7	0.0	0.0	0.0	0.0
21	Other						5.4	5.4			0.0	
22	Subtotal		4,486.0	4,662.3	4,826.6	5,144.8	5,114.9	(29.8)	5,087.4	4,904.6	(182.9)	5,182.4
23	Revenue from Deferral Account Rate Rider		223.7	233.2	240.6	0.0	0.2	0.2	0.0	0.0	0.0	0.0
24	Total		4,709.7	4,895.5	5,067.2	5,144.8	5,115.1	(29.6)	5,087.4	4,904.6	(182.9)	5,182.4
25	**Deferral Account Rate Rider**		5.0%	5.0%	5.0%	0.0%	0.0%		0.0%	0.0%		0.0%
	Average Revenues ($/MWh)											
26	Residential		106.1	110.0	112.5	121.1	120.5	(0.6)	119.4	116.3	(3.1)	118.5
27	Light Industrial and Commercial		90.4	93.8	96.4	103.6	103.9	0.3	101.7	102.5	0.8	103.3
28	Large Industrial		55.6	57.4	59.8	64.7	63.4	(1.3)	64.5	60.8	(3.8)	64.9
29	Irrigation		75.0	67.6	80.3	81.9	88.9	7.0	78.1	95.2	17.1	87.4
30	Street Lighting		169.5	177.5	182.5	194.1	189.2	(4.9)	192.2	193.0	0.7	189.1
31	New Westminster & Tongass		59.7	61.9	64.3	68.8	68.3	(0.4)	67.5	65.5	(2.0)	67.6
32	Fortis		61.4	64.6	71.3	72.5	70.0	(2.5)	71.0	66.4	(4.6)	68.2
33	Seattle City Light		41.0	38.2	96.1	92.7	96.6	3.9	92.4	97.4	5.0	97.4
34	Liquefied Natural Gas		1,080.8	203.3	79.2	85.4	80.0	(5.5)	0.0	0.0	0.0	0.0
35	Other					0.0	26.1	26.1	0.0	0.0	0.0	0.0
36	Total (Excluding Misc Rev)		90.8	94.0	96.7	99.0	98.5	(0.5)	97.9	97.2	(0.7)	98.8

BC Hydro
F22 RRA Compliance

Schedule 14.0
Page 75

Domestic Energy Sales and Revenue

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Baseline											
37	COVID-19 Residential Grants to CCF					0.0	0.0	0.0	0.0	(37.3)	(37.3)	0.0
38	COVID-19 SGS Waivers to MCPP					0.0	0.0	0.0	0.0	(6.4)	(6.4)	0.0
39	Skagit and Ancillary Revenue to HDA					36.1	29.7	(6.4)	35.9	30.2	(5.7)	30.2
40	Load Variance					5,099.7	5,079.5	(20.3)	5,036.5	4,901.1	(135.5)	5,187.7
41	Biomass Energy Program Variance					9.0	5.8	(3.2)	15.2	16.9	1.7	15.9
42	Total					5,144.8	5,114.9	(29.8)	5,087.6	4,904.6	(183.1)	5,233.8

BC Hydro
F22 RRA Compliance

Schedule 15.0
Page 76

Miscellaneous Revenue
($ million)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Generation											
1	Amortization of Contributions	11.0 L7	0.3	0.3	0.3	0.3	0.3	0.0	0.2	0.3	0.0	0.2
2	Other		2.0	1.6	2.0	1.6	2.2	0.6	1.7	1.5	(0.2)	1.9
3	Total		2.3	1.9	2.3	1.9	2.5	0.6	1.9	1.7	(0.2)	2.2
	Transmission											
4	External OATT	3.4 L74	11.8	11.4	15.4	15.9	10.7	(5.2)	15.9	12.9	(3.0)	11.1
5	FortisBC Wheeling Agreement		4.8	5.1	5.2	5.2	5.2	(0.0)	5.3	5.3	0.0	5.3
6	Secondary Revenue		7.6	7.5	8.7	6.0	7.1	1.2	6.2	6.9	0.7	7.1
7	Interconnections		3.6	2.9	4.9	2.2	6.4	4.2	2.2	4.6	2.4	4.6
8	Amortization of Contributions	11.0 L18:L19-L14	13.5	14.4	21.1	14.6	14.6	0.1	15.0	14.8	(0.2)	11.0
9	NTL Supplemental Charge		2.7	2.0	2.3	2.3	2.3	0.0	2.3	2.4	0.1	2.4
10	Total		44.1	43.3	57.6	46.1	46.4	0.3	46.8	46.8	(0.1)	41.4
	Distribution											
11	Secondary Use Revenue & Other		15.3	15.9	20.9	14.1	17.0	2.8	14.1	15.8	1.7	16.9
12	Amortization of Contributions	11.0 L29:L31-L26	37.5	39.8	38.6	44.8	49.1	4.3	47.9	48.4	0.5	51.7
13	Total		52.7	55.7	59.5	58.9	66.0	7.1	62.0	64.2	2.2	68.6
	Customer Care											
14	Meter/Trans Rents & Power Factor Surcharges		12.3	12.7	14.7	14.6	16.1	1.5	14.9	15.9	1.1	16.2
15	Smart Metering & Infrastructure Impact		4.5	3.8	3.3	2.1	2.2	0.1	1.7	1.5	(0.2)	1.5
16	Diversion Net Recoveries		0.5	0.4	0.2	0.1	0.2	0.1	0.1	0.1	0.0	0.1
17	Other Operating Recoveries		4.3	4.4	4.0	4.5	4.1	(0.3)	4.6	3.8	(0.8)	4.2
18	Customer Crisis Fund Rider Revenue		0.0	0.0	4.1	5.3	4.4	(0.9)	5.3	5.3	0.0	0.5
19	Other		3.3	2.1	3.2	3.0	3.1	0.1	3.0	2.5	(0.5)	3.0
	Waneta 2/3											
20	Lease revenue from Teck					75.2	75.2	0.0	76.7	76.7	0.0	78.2
21	Teck portion of operating costs				3.7	5.7	5.4	(0.3)	5.9	5.9	0.0	6.1
22	Teck portion of water rentals				2.4	3.5	3.3	(0.2)	3.7	3.2	(0.5)	3.5
23	Teck portion of property taxes				0.1	0.6	0.9	0.3	0.6	0.8	0.2	0.8
24	Subtotal		0.0	0.0	6.3	84.9	84.7	(0.2)	86.9	86.6	(0.3)	88.6
25	Total		24.9	23.4	35.6	114.5	114.8	0.3	116.4	115.7	(0.8)	114.1
	Business Support											
26	Corporate General Rents		4.6	4.3	4.1	3.7	3.9	0.2	3.8	2.9	(0.9)	3.6
27	Late Payment Charges		7.1	7.6	8.0	7.9	7.1	(0.8)	8.1	5.4	(2.7)	7.9
28	MMBU Secondary Revenue		5.8	5.9	3.9	3.8	3.9	0.1	3.8	3.2	(0.7)	3.3
29	Low Carbon Fuel Credits											31.4
30	Other		2.0	1.6	1.4	0.7	1.4	0.7	0.7	0.4	(0.3)	0.9
31	Total		19.5	19.4	17.4	16.1	16.4	0.2	16.4	11.9	(4.5)	47.1
32	**Total Before Regulatory Accounts**		143.4	143.7	172.5	237.5	246.0	8.5	243.6	240.2	(3.3)	273.5

BC Hydro
F22 RRA Compliance

Schedule 15.0
Page 77

Miscellaneous Revenue
($ million)

Line		Reference Column	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
			1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Deferral Account Additions											
33	Waneta 2/3											
34	Lease revenue from Teck				50.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Teck portion of capital expenditures				1.3	3.1	1.3	(1.8)	3.5	3.5	0.0	15.5
36	Subtotal		0.0	0.0	51.9	3.1	1.3	(1.8)	3.5	3.5	0.0	15.5
	Regulatory Account Additions											
37	Smart Metering & Infrastructure Impact		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	Minimum Reconnection Charge		(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Subtotal		(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	**Total Gross Miscellaneous Revenue**		143.1	143.7	224.4	240.6	247.3	6.7	247.0	243.7	(3.3)	289.0
41	**Transfers to NHDA**		0.0	0.0	(51.9)	(3.1)	(1.3)	1.8	(3.5)	(3.5)	(0.0)	(15.5)
42	**Transfers to Regulatory Accounts**		0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
43	**Total Current Miscellaneous Revenue**		143.4	143.7	172.5	237.5	246.0	8.5	243.6	240.2	(3.3)	273.5

BC Hydro
F22 RRA Compliance

Schedule 16.0
Page 78

Full-Time Equivalents (FTEs)

Line		Reference	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Column		1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Integrated Planning											
1	Energy Planning and Analytics		29	31	38	44	45	1	44	44	(0)	44
2	Dam Safety		34	34	34	37	33	(5)	37	39	2	39
3	Stations Asset Planning		51	49	44	59	56	(3)	59	56	(3)	56
4	Line Asset Planning		124	127	131	131	133	2	131	131	(0)	144
5	Interconnections and Shared Assets		36	43	46	47	44	(3)	47	46	(1)	46
6	Engineering Design		436	432	420	457	457	1	457	446	(11)	408
7	Engineering Services		103	127	163	189	180	(9)	189	202	13	239
8	Business Unit Support		4	3	3	3	3	(0)	3	3	(0)	3
9	Total		820	845	880	967	950	(17)	967	967	(0)	980
	Capital Infrastructure Project Delivery											
10	Project Delivery		324	387	408	450	418	(33)	450	432	(19)	431
11	Indigenous Relations		57	59	64	68	69	0	68	73	5	74
12	Environment		86	90	90	94	93	(1)	94	95	1	95
13	Properties		110	114	121	123	116	(6)	123	123	0	123
14	Business Unit Support		3	3	3	3	3	0	3	3	(0)	3
15	Total		581	652	686	739	699	(39)	739	726	(13)	726
	Operations											
16	Program and Contract Management		205	206	219	228	251	23	228	274	46	280
17	Line Field Operations		822	841	858	922	876	(46)	922	924	1	924
18	Stations Field Operations		829	818	817	777	712	(65)	777	724	(53)	724
19	Distribution Design and Customer Connections		325	347	360	379	356	(23)	379	347	(32)	379
20	Construction Services		411	409	424	397	422	25	397	397	0	397
21	Generation System Operations		91	95	91	89	91	2	89	80	(9)	81
22	Transmission and Distribution System Operations		170	174	176	197	195	(2)	197	197	(0)	197
23	Business Unit Support		3	3	5	5	7	2	5	4	(1)	4
24	Total		2,855	2,893	2,951	2,995	2,910	(85)	2,995	2,947	(48)	2,985
	Safety & Compliance											
25	Safety Systems and Assurance		48	49	46	52	48	(4)	52	51	(1)	46
26	Learning and Development		456	437	384	317	338	20	300	293	(7)	251
27	Field Safety Services		50	56	66	62	67	5	62	62	(0)	62
28	Security and Emergency Management		20	25	28	31	29	(2)	31	31	0	33
29	Reliability Compliance		3	4	5	5	6	1	5	7	2	22
30	Business Unit Support		2	2	2	2	2	0	2	2	0	3
31	Total		579	572	530	469	490	21	452	446	(6)	416

BC Hydro
F22 RRA Compliance

Schedule 16.0
Page 79

Full-Time Equivalents (FTEs)

Line		F2017 Actual	F2018 Actual	F2019 Actual	F2020 Decision	F2020 Actual	F2020 Diff	F2021 Decision	F2021 Forecast	F2021 Diff	F2022 Decision
	Reference Column	1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Finance, Technology, Supply Chain										
32	Finance	194	196	199	206	203	(3)	206	211	5	211
33	Technology	186	226	264	269	269	(1)	269	273	4	283
34	Supply Chain	421	447	482	468	501	33	468	476	8	475
35	Business Unit Support	3	3	3	3	3	(0)	3	3	(0)	3
36	Total	805	871	947	946	975	29	946	963	17	972
	People, Customer, Corporate Affairs										
37	Human Resources	84	88	117	124	123	(0)	124	126	2	126
38	Customer Service	154	191	438	479	483	4	479	484	5	492
39	Conservation and Energy Management	110	112	116	116	116	1	116	116	(0)	116
40	Communications and Community Engagement	94	95	105	107	103	(5)	107	108	1	108
41	Regulatory and Rates	21	22	24	23	24	1	23	23	0	23
42	Ethics and Merit Office	2	3	4	5	5	(0)	5	5	0	5
43	Smart Metering & Infrastructure	0	0	0	0	0	0	0	0	0	0
44	Business Unit Support	3	3	3	3	3	0	3	3	(0)	3
45	Total	469	513	806	856	857	0	856	864	8	872
	Other										
46	Office of the General Counsel	36	35	36	42	39	(2)	41	41	0	41
47	Office of the President and Chief Executive Officer	4	3	3	3	3	0	3	3	(0)	3
48	Site C Project	167	226	322	460	445	(15)	472	497	26	504
49	Independent Power Producer Capital Leases	0	0	0	0	0	0	0	0	0	0
50	Corporate Costs	0	0	0	0	0	0	0	0	0	0
51	Capitalized Costs	0	0	0	0	0	0	0	0	0	0
52	Total	208	264	361	505	487	(17)	516	542	26	548
53	**Total**	6,315	6,611	7,161	7,477	7,369	(108)	7,471	7,455	(16)	7,500
	Summary										
54	Regular Hour FTEs (excl. Smart Metering & Infrastructure & Site C Project)	5,578	5,791	6,257	6,461	6,330	(131)	6,449	6,439	(10)	6,446
55	Smart Metering & Infrastructure (SMI)	0	0	0	0	0	0	0	0	0	0
56	Site C Project	157	212	296	422	403	(19)	431	455	24	459
57	Subtotal Regular Hour FTEs	5,735	6,004	6,553	6,884	6,733	(150)	6,880	6,894	14	6,905
58	Overtime Hour FTEs (excl. Smart Metering & Infrastructure & Site C Project)	570	593	583	556	594	38	551	519	(32)	550
59	Smart Metering & Infrastructure (OT Hour FTEs)	0	0	0	0	0	0	0	0	0	0
60	Site C Project (OT Hour FTEs)	10	14	26	38	42	4	41	42	2	45
61	Total	6,315	6,611	7,161	7,477	7,369	(108)	7,471	7,455	(16)	7,500

BC Hydro
F22 RRA Compliance

Schedule 16.0
Page 80

Full-Time Equivalents (FTEs)

			F2017	F2018	F2019	F2020			F2021			F2022
		Reference	Actual	Actual	Actual	Decision	Actual	Diff	Decision	Forecast	Diff	Decision
Line		Column	1	2	3	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10
	Summary of FTE's by Function											
	Regular Hour FTEs											
62	Operating		3,747	3,859	4,248	4,250	4,350	100	4,247	4,259	12	4,309
63	Capital		1,829	1,983	2,135	2,470	2,215	(255)	2,469	2,469	0	2,430
64	Deferred		160	161	169	164	168	4	164	166	2	166
65	Total		5,735	6,004	6,553	6,884	6,733	(150)	6,880	6,894	14	6,905
	Overtime Hour FTEs											
66	Operating		336	350	360	220	360	141	219	229	11	235
67	Capital		243	256	247	373	274	(100)	373	332	(41)	360
68	Deferred		1	1	1	0	2	2	0	0	0	0
69	Total		580	607	609	593	636	42	592	561	(30)	595
	Total FTEs by Function											
70	Operating		4,082	4,209	4,608	4,470	4,710	241	4,466	4,489	23	4,544
71	Capital		2,072	2,239	2,382	2,843	2,488	(355)	2,841	2,801	(41)	2,790
72	Deferred		161	162	171	164	170	6	164	166	2	166
73	Total		6,315	6,611	7,161	7,477	7,369	(108)	7,471	7,455	(16)	7,500

BC Hydro
Power smart

BC Hydro Fiscal 2022
Revenue Requirements Application

Compliance with
BCUC Decision and Order G-187-21

Appendix B

Tariff Sheets – Black-lined and Clean

1. RESIDENTIAL SERVICE

RATE SCHEDULES 1101, 1121 – RESIDENTIAL SERVICE

Availability	For Residential Service. Service is normally single phase, 60 hertz at the Secondary Voltage available. In BC Hydro's discretion, Service may be three phase 120/208 or 240 volts.
Applicable in	Rate Zone I.
Rate	1. Rate Schedule 1101 – Residential Service: **Basic Charge:** 20.77~~20.80~~ ¢ per day plus **Energy Charge:** (a) For Customers billed monthly: Step 1: First 675 kWh per month@ 9.39~~9.41~~ ¢/kWh Step 2: Additional kWh per month@ 14.08~~14.10~~ ¢/kWh (b) For Customers billed bi-monthly: Step 1: First 1350 kWh per two months@ 9.39~~9.41~~ ¢/kWh Step 2: Additional kWh per two months@ 14.08~~14.10~~ ¢/kWh Note: For billing purposes, Step 1 is pro-rated on a daily basis. **Minimum Charge:** The Basic Charge

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

	2. Rate Schedule 1121 – Multiple Residential Service: **Basic Charge:** 20.77~~20.80~~ ¢ per Dwelling per day plus **Energy Charge:** Per Dwelling (a) For Customers billed monthly: Step 1: First 675 kWh. per month@ 9.39~~9.41~~ ¢/kWh Step 2: Additional kWh per month@ 14.08~~14.10~~ ¢/kWh (b) For Customers billed bi-monthly: Step 1: First 1350 kWh per two months@ 9.39~~9.41~~ ¢/kWh Step 2: Additional kWh per two months@ 14.08~~14.10~~ ¢/kWh Note: For billing purposes, Step 1 is pro-rated on a daily basis. **Minimum Charge:** The Basic Charge per Dwelling
Discount for Ownership of Transformers	A discount of 25 ¢ per month per kW of Maximum Demand will be applied to amounts owing under Rate Schedule 1121 if the Customer supplies Transformation. BC Hydro will install Metering Equipment with both Demand and Energy measurement capability at the Secondary Voltage.
Special Conditions	1. The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under these Rate Schedules must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission. 2. Rate Schedule 1121 applies if the Premises contains more than two Dwellings.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

1. RESIDENTIAL SERVICE

RATE SCHEDULE 1105 – RESIDENTIAL SERVICE – DUAL FUEL (CLOSED)

Availability	For residential space heating and water heating. Electricity purchased under this Rate Schedule will be separately metered. Service is single phase, 60 hertz, at 120/240 or 240 volts. This Rate Schedule is available only for Premises served under this Rate Schedule on January 15, 1990 and continuously thereafter and only in Premises where there has been no change in Customer since April 1, 2008.
Applicable in	Rate Zone I in areas where and when, in BC Hydro's opinion, BC Hydro's transmission, sub-transmission and distribution circuit feeders are or will be capable of handling the load.
Rate	**Energy Charge:** 8.58 ¢ per kWh
Special Conditions	1. Service under this Rate Schedule is not available to any Premises where Service was previously supplied and Terminated. 2. BC Hydro will upgrade an existing Service Connection supplying firm load to serve additional load in accordance with the Electric Tariff, however, no new or additional load is permitted under this Rate Schedule at any time. All unauthorized consumption of Electricity as estimated by BC Hydro will be billed at the rate for Electricity on the appropriate default Residential Service Rate Schedule. 3. The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under this Rate Schedule must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase	The rate under this Rate Schedule is set in accordance with BCUC Order No. G-194-17. Effective April 1, 2021 a~~n~~ ~~interim~~ rate increase of 1.00~~16~~% is applied.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

1. RESIDENTIAL SERVICE

RATE SCHEDULES 1107, 1127 – RESIDENTIAL SERVICE – ZONE II

Availability	For Residential Service. Service is normally single phase, 60 hertz at the Secondary Voltage available. In BC Hydro's discretion, Service may be three phase 120/208 or 240 volts.
Applicable in	Rate Zone II.
Rate	1. Rate Schedule 1107 – Residential Service: **Basic Charge:** 22.15~~22.18~~ ¢ per day plus **Energy Charge:** First 1500 kWh per month @ 11.25~~11.27~~ ¢ per kWh All additional kWh per month @ 19.32~~19.35~~ ¢ per kWh **Minimum Charge:** The Basic Charge 2. Rate Schedule 1127 – Multiple Residential Service: **Basic Charge:** 22.15~~22.18~~ ¢ per Dwelling per day plus **Energy Charge:** First 1500 kWh per Dwelling per month @ 11.25~~11.27~~ ¢ per kWh All additional kWh per month @ 19.32~~19.35~~ ¢ per kWh **Minimum Charge:** The Basic Charge per Dwelling

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

Discount for Ownership of Transformers	A discount of 25 ¢ per month per kW of Maximum Demand will be applied to amounts owing under Rate Schedule 1127 if the Customer supplies Transformation. BC Hydro will install Metering Equipment with both Demand and Energy measurement capability at the Secondary Voltage.
Special Conditions	1. The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under these Rate Schedules must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission. 2. Rate Schedule 1127 applies if the Premises contains more than two Dwellings.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a~~n interim~~ rate increase of 1.00~~1.16~~% before rounding.

1. RESIDENTIAL SERVICE

RATE SCHEDULE 1148 – RESIDENTIAL SERVICE – ZONE II (CLOSED)

Availability	For Residential Service in Rate Zone II where a permanent electric space heating system is in use, providing such system was installed prior to October 10, 1966. This Rate Schedule is available only to a Customer and Premises served under this Rate Schedule on April 24, 1992 and continuously thereafter.
Applicable in	Rate Zone II.
Rate	**Basic Charge:** 22.15~~22.18~~ ¢ per day plus **Energy Charge:** 11.25~~11.27~~ ¢ per kWh **Minimum Charge:** The Basic Charge
Special Conditions	The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under this Rate Schedule must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~**Interim**~~ **Rate Increase**	Effective April 1, 2021 the rates under this Rate Schedule include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:______________________________

ORDER NO.______________________________ ____
COMMISSION SECRETARY

1. RESIDENTIAL SERVICE

RATE SCHEDULES 1151, 1161 – EXEMPT RESIDENTIAL SERVICE

Availability	For Residential Service and uses exempted from Rate Schedules 1101 and 1121 (Residential Service), including: 1. Use on farms as set out in the definition of Residential Service in the Terms and Conditions; and 2. Use in Rate Zone IB. Service is normally single phase, 60 hertz at the Secondary Voltage available. In BC Hydro's discretion, Service may be three phase 120/208 or 240 volts.
Applicable in	Rate Zone I and Rate Zone IB.
Rate	1. Rate Schedule 1151 – Residential Service: **Basic Charge:** 22.15~~22.18~~ ¢ per day plus **Energy Charge:** 11.25~~11.27~~ ¢ per kWh **Minimum Charge:** The Basic Charge 2. Rate Schedule 1161 – Multiple Residential Service: **Basic Charge:** 22.15~~22.18~~ ¢ per day per Dwelling per day plus **Energy Charge:** 11.25~~11.27~~ ¢ per kWh **Minimum Charge:** The Basic Charge per Dwelling

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

Discount for Ownership of Transformers	A discount of 25 ¢ per month per kW of Maximum Demand will be applied to amounts owing under Rate Schedule 1161 if the Customer supplies Transformation. BC Hydro will install Metering Equipment with both Demand and Energy measurement capability at the Secondary Voltage.
Special Conditions	The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under these Rate Schedules must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a ~~n interim~~ rate increase of 1.00~~1.16~~% before rounding.

2. GENERAL SERVICE

RATE SCHEDULES 1200, 1201, 1210, 1211 – EXEMPT GENERAL SERVICE (35 KW AND OVER)

Availability	For Customers who qualify for General Service where supply is 60 hertz, single or three phase at Secondary or Primary Voltage and Billing Demand is 35 kW or more. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone IB.
Rate	**Basic Charge:** 26.56~~26.61~~ ¢ per day plus **Demand Charge:** First 35 kW of Billing Demand per Billing Period @ $0.00 per kW Next 115 kW of Billing Demand per Billing Period @ $6.47~~6.48~~ per kW All additional kW of Billing Demand per Billing Period @ $12.41~~12.43~~ per kW plus **Energy Charge:** First 14800 kWh of Energy consumption in the Billing Period @ 12.64~~12.66~~ ¢ per kWh All additional kWh of Energy consumption in the Billing Period @ 6.07~~6.08~~ ¢ per kWh

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per Billing Period per kW of Billing Demand will be applied to the above charges if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.
Monthly Minimum Charge	50% of the highest Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding 11 Billing Periods. For the purpose of this provision an on-peak period commences on November 1 in any year and terminates on March 31 of the following year.
Rate Schedules	1. Rate Schedule 1200: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1201: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1210: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1211: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

Definitions	Billing Demand is the Maximum Demand in the Billing Period, subject to Special Condition No. 1. Billing Period means a month between regular meter readings, provided that in cases where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.
Special Conditions	1. Metering Equipment with both Demand and Energy measurement capability will normally be installed. Until such Metering Equipment is installed, or if the installed Metering Equipment does not have Demand measurement capability, Billing Demand will be as estimated by BC Hydro. 2. Migration rule: Customers taking Service under these Rate Schedules will be moved to Service under Rate Schedule 1300, 1301, 1310 or 1311 (Small General Service) if Billing Demand in each of the last 12 consecutive Billing Periods was less than 35 kW.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

2. GENERAL SERVICE

RATE SCHEDULES 1205, 1206, 1207 – GENERAL SERVICE – DUAL FUEL (CLOSED)

Availability	For general space heating, water heating and industrial process heating. Electricity purchased under these Rate Schedules will be separately metered. Service is 60 hertz single or three phase at the Secondary or Primary Voltage available. BC Hydro reserves the right to determine the voltage of the Service Connection. These Rate Schedules are available only for Premises served under these Rate Schedules on January 15, 1990 and continuously thereafter, only with respect to equipment served under these Rate Schedules on January 15, 1990 and continuously thereafter, and only in Premises where there has been no change in Customer since April 1, 2008.
Applicable in	Rate Zone I in areas where, in BC Hydro's opinion, BC Hydro's transmission, sub-transmission and distribution circuit feeders are or will be capable of handling the load.
Rate	Except as stated hereunder the rate will be: **Energy Charge:** First 8000 kWh per month @ 6.15~~6.16~~ ¢ per kWh All additional kWh per month @ 4.02~~4.03~~ ¢ per kWh
Rate Schedules	1. Rate Schedule 1205 – Small Commercial Applications: Applies to a Customer whose heating load is mostly in support of a commercial activity and whose firm Electricity is billed on a General Service (under 35 kW) Rate Schedule.

ACCEPTED:__________________________

ORDER NO.__________________________

____
COMMISSION SECRETARY

	2. Rate Schedule 1206 – Large Commercial Applications: Applies to a Customer whose heating load is mostly in support of a commercial activity and whose firm Electricity is billed on a General Service (35 kW and over) Rate Schedule. 3. Rate Schedule 1207 – Industrial Applications: Applies to a Customer whose heating load is mostly in support of an industrial activity and whose firm Electricity is billed on a General Service Rate Schedule or for farm use on a Residential Rate Schedule.
Special Conditions	1. Service under these Rate Schedules will not be available to any Premises beyond March 31, 2023. 2. These Rate Schedules are not available to Premises where Electricity under it was previously supplied and Terminated. 3. No other load than that stipulated in the Availability clause is permitted under these Rate Schedules. Any unauthorized use of Electricity or any refusal by a Customer to permit access to Premises in accordance with the Terms and Conditions of BC Hydro's Electric Tariff will result in immediate Termination under the applicable Rate Schedule and all unauthorized consumption as estimated by BC Hydro will be billed at the rate for Electricity on the appropriate default General Service Rate Schedule. 4. In addition to and without restriction of any other limitations of liability of BC Hydro, BC Hydro will specifically not be liable for any loss, damage, injury or expense occasioned to or suffered by any Customer receiving Service on these Rate Schedules, or by any other Person, for any reason whatsoever. 5. Replacement of existing heating equipment is allowed provided the rated capacity (equivalent kW) of the new equipment is not higher than the existing equipment. No new load or additional load is allowed

Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:

ORDER NO.

COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULE 1234 – SMALL GENERAL SERVICE (UNDER 35 KW) – ZONE II

Availability	For all purposes where a meter with Demand measurement capability is not installed because the Customer's Demand as estimated by BC Hydro is less than 35 kW. Supply is 60 hertz, single or three phase at an available Secondary Voltage.
Applicable in	Rate Zone II.
Rate	**Basic Charge:** 26.56~~26.61~~ ¢ per day plus **Energy Charge:** First 7000 kWh per month @ 12.64~~12.66~~ ¢ per kWh All additional kWh per month @ 21.04~~21.07~~ ¢ per kWh **Minimum Charge:** The Basic Charge
Special Conditions	Special Conditions for Unmetered Service: 1. BC Hydro may permit unmetered Service under this Rate Schedule if it can estimate to its satisfaction the Energy used in kilowatt hours over a period of two months based on the connected load and the hours of use. 2. The Customer, if required by BC Hydro, will provide and maintain such controls, including timing devices, as BC Hydro considers necessary, and facilities satisfactory to BC Hydro for the maintenance of such controls. 3. The hours of use per period will be as specified by the Customer or as estimated by BC Hydro, whichever is greater.

4. The Customer will supply, install and maintain all wiring, fixtures, control devices and equipment, including the controls and devices described in Special Condition No. 2, at the expense of the Customer.

5. All wiring, fixtures, control devices and equipment and the method of installing, operating and maintaining the same are subject to the approval of BC Hydro which approval may be withdrawn by BC Hydro, at any time, at BC Hydro's sole discretion.

6. The Customer will notify BC Hydro immediately of any proposed or actual change in load, load characteristics, or hours of use.

7. BC Hydro may at any time, in its sole discretion, install Metering Equipment, and thereafter bill the Customer on the appropriate Rate Schedule as a metered account.

8. For display signs and signboard lighting, where hours of use are controlled by timing devices, the following turn-on times will apply, unless BC Hydro otherwise agrees in writing:

Period	Turn-on Time
January 1 to January 15:	4:00 p.m.
January 16 to February 28:	4:30 p.m.
March 1 to April 30:	6:30 p.m.
May 1 to August 15:	8:30 p.m.
August 16 to September 30:	6:30 p.m.
October 1 to November 15:	4:30 p.m.
November 16 to December 31:	4:00 p.m.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

	9. In all cases, where hours of use of display signs or signboard lighting commence at dusk and are controlled either by timing devices or by photo-electric cells, the following hours of use for a period of two months will be deemed for billing purposes: Dusk to 10 p.m.: 216 hours Dusk to 11 p.m.: 270 hours Dusk to 12 p.m.: 330 hours Dusk to 1 a.m.: 380 hours Dusk to Dawn: 666 hours (All times are Pacific Time.)
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

2. GENERAL SERVICE

RATE SCHEDULE 1253 – DISTRIBUTION SERVICE – IPP STATION SERVICE

Availability	For Customers who are Independent Power Producers (**IPPs**) served at distribution voltage, on an interruptible basis.
Applicable in	Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Energy Charge:** The sum, over the billing period, of the hourly Energy consumed multiplied by the entry in the Intercontinental Exchange (**ICE**) Mid Columbia (Mid-C) Peak, and Mid-C Off-Peak weighted average index price as published by the ICE in the ICE Day Ahead Power Price Report that corresponds to the time when consumption occurred, during that hour.
Monthly Minimum Charge	$48.70~~48.78~~
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. 2. BC Hydro may, without notice to the Customer, refuse to supply or terminate the supply of Electricity under this Rate Schedule if at any time BC Hydro does not have sufficient energy or capacity. 3. Prior to taking Electricity under this Rate Schedule, the Customer may be required to obtain approval from BC Hydro. BC Hydro will advise the Customer of the need to obtain approval prior to the taking of Electricity under this Rate Schedule. 4. Electricity taken under this Rate Schedule is to be used solely for maintenance and black-start requirements and will not displace electricity that would normally be generated by the Customer.

ACCEPTED:________________________

ORDER NO.________________________

____
COMMISSION SECRETARY

Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the Monthly Minimum Charge under this Rate Schedule includes a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULES 1255, 1256, 1265, 1266 – GENERAL SERVICE (35 KW AND OVER) – ZONE II

Availability	For all purposes. Supply is 60 hertz, single or three phase at Secondary or Primary Voltage. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone II.
Rate	**Basic Charge:** 26.56~~26.61~~ ¢ per day plus **Energy Charge:** First 200 kWh per kW of Billing Demand per month @ 12.64~~12.66~~ ¢ per kWh All additional kWh per month @ 21.04~~21.07~~ ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per month per kW of Billing Demand will be applied to the above rate if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts the discount for metering at a Primary Voltage will be applied first.
Monthly Minimum Charge	The monthly minimum charge to be paid by a Customer on Rate Schedule 1255, 1256, 1265 or 1266, as applicable, will be the charge the Customer would have been billed under Rate Schedule 1200, 1201, 1210 or 1211 (Exempt General Service – 35 kW and over), respectively.

ACCEPTED:________________________

ORDER NO.________________________

____
COMMISSION SECRETARY

Rate Schedules	1. Rate Schedule 1255: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation.
	2. Rate Schedule 1256: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1265: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1266: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Special Conditions	1. Metering Equipment with both Demand and Energy measurement capability will normally be installed. Until such Metering Equipment is installed, or if the installed Metering Equipment does not have Demand measurement capability, Billing Demand will be as estimated by BC Hydro. 2. Where the Customer’s Demand is or is likely to be in excess of 45 kVA, BC Hydro may require such Customer to execute a special contract for Service, including such special conditions as BC Hydro, in its sole discretion considers necessary.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULE 1268 – DISTRIBUTION SERVICE – IPP DISTRIBUTION TRANSPORTATION ACCESS

Availability	For Customers who have generators connected to BC Hydro's distribution system and who want to access BC Hydro's transmission system pursuant to and in accordance with BC Hydro's Open Access Transmission Tariff (OATT).
Applicable in	Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Distribution Transportation Charge:** 0.196 ¢ per kWh
Special Conditions	1. The Customer is required to pay the costs, including the cost of altering existing facilities, to connect the generator to BC Hydro's distribution system in accordance with BC Hydro's Connection Requirements for Utility or Non-Utility Generation, 35 kV and Below. 2. For Customers with self-generation (i.e., with a Customer Baseline Load (**CBL**) greater than zero), this Rate Schedule is only applicable to sales of Surplus Energy. It may not be used by self-generating Customers who appear to have varied their demand for power from BC Hydro based on the actual or anticipated difference between BC Hydro's rate for providing Service to them and the market price of power. 3. For the purposes of this Rate Schedule, "Surplus Energy" in any period is the energy made available from generation by the Customer calculated as the difference between the Customer's CBL and the Customer's actual consumption from BC Hydro in that period.

ACCEPTED:____________________

ORDER NO.____________________

COMMISSION SECRETARY

	4. The Customer's CBL is established, in general, by determining the Customer's Energy consumption, on a monthly basis, for the past three years; in cases where inadequate history exists, alternative methods may be used to determine a Customer's CBL. Once established, the Customer's CBL will not be automatically adjusted for changes in the Customer's net metered consumption from BC Hydro. Any subsequent changes to the CBL must be due to changes in the Customer's load and not due to changes in its generation. The Customer must provide metered output from its generator which demonstrates an increase in generation output commensurate in time and amount with the Surplus Energy transported using this Rate Schedule. Where it appears that the Customer has transported on this Rate Schedule Energy that is not Surplus Energy, BC Hydro will provide replacement energy to the Customer's load at market prices, subject to Commission approval for such sales. 5. The metering point to determine the electricity being delivered to BC Hydro's distribution system will be determined by BC Hydro. The electricity delivered to BC Hydro's distribution system will also be deemed to be delivered to BC Hydro's transmission system (that is, no distribution loss adjustment will be applied to the electricity from an independent power producer or self-generator when determining capacity and energy delivered to BC Hydro's transmission system).
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rate under this Rate Schedule includes a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULE 1280 – SHORE POWER SERVICE (DISTRIBUTION)

Availability	For the supply of Shore Power to Port Customers who qualify for General Service for use by Eligible Vessels while docked at the Port Customer's Port Facility, on an interruptible basis. Shore Power Service is supplied at 60 Hz, three phase at Primary Voltage.
Applicable in	Rate Zone I.
Rate	**Administrative Charge:** $150.00 per month plus **Energy Charge:** 10.442~~10.459~~ ¢ per kWh
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. BC Hydro may refuse or Terminate Service under this Rate Schedule in circumstances where BC Hydro does not have sufficient energy or capacity. For greater certainty, BC Hydro will not be required to construct an Extension for the purpose of increasing the capacity of BC Hydro's distribution system to provide Shore Power Service under this Rate Schedule. 2. The terms and conditions under which Shore Power Service is supplied are contained in the Shore Power Service Agreement (Electric Tariff Supplement No. 86). The Port Customer will pay to BC Hydro the charges set out in this Rate Schedule in addition to any charges set out in the Shore Power Service Agreement. 3. A Port Customer that provides Port Electricity at a Port Facility under Rate Schedules 1600, 1601, 1610, 1611 or 1823 is not eligible to take Shore Power Service under this Rate Schedule to provide Port Electricity to that Port Facility, or any Port Facility served by the same BC Hydro delivery facilities.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

	4. On each occasion, if any, that BC Hydro is required to dispatch power line technicians or other workers to operate the switchgear for each connect and disconnect of Eligible Vessels docked at the Port Customer's Port Facility, BC Hydro will charge, and the Port Customer will pay, the reasonable time and labour costs for this service. The charge will be based on prevailing BC Hydro contracted labour rates and will be separately itemized on the Port Customer's monthly bill.
Definitions	For purposes of this Rate Schedule, capitalized terms have the meanings given to them in Electric Tariff Supplement No. 86.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

2. GENERAL SERVICE

RATE SCHEDULES 1300, 1301, 1310, 1311 – SMALL GENERAL SERVICE (UNDER 35 KW)

Availability	For Customers who qualify for General Service and whose Demand, metered or estimated by BC Hydro, as applicable, is less than 35 kW. Supply is 60 hertz, single or three phase at a Secondary or Primary Voltage.
Applicable in	Rate Zone I and Rate Zone IB.
Rate	**Basic Charge:** 36.22~~36.28~~ ¢ per day plus **Energy Charge:** 12.45~~12.47~~ ¢ per kWh **Minimum Charge:** The Basic Charge
Discounts	1. A discount of 1½% will be applied to the above charges if Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per month per kW of Demand will be applied if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.
Rate Schedules	1. Rate Schedule 1300: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1301: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation.

ACCEPTED:____________________

ORDER NO.____________________

____
COMMISSION SECRETARY

	3. Rate Schedule 1310: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1311: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Special Conditions	Special Conditions for Unmetered Service: 1. BC Hydro may permit unmetered Service under these Rate Schedules if it can estimate to its satisfaction the Energy used in kilowatt hours over a period of two months based on the connected load and the hours of use. 2. The Customer, if required by BC Hydro, will provide and maintain such controls, including timing devices, as BC Hydro considers necessary, and facilities satisfactory to BC Hydro for the maintenance of such controls. 3. The hours of use per period will be as specified by the Customer, or as estimated by BC Hydro, whichever is greater. 4. The Customer will supply, install and maintain all wiring, fixtures, control devices and equipment, including the controls and devices described in Special Condition No. 2, at the expense of the Customer. 5. All wiring, fixtures, control devices and equipment and the method of installing, operating and maintaining the same are subject to the approval of BC Hydro which approval may be withdrawn by BC Hydro, at any time, at BC Hydro's sole discretion. 6. The Customer will notify BC Hydro immediately of any proposed or actual change in load, load characteristics, or hours of use.

7. BC Hydro may at any time, in its sole discretion, install Metering Equipment, and thereafter bill the Customer on the appropriate Rate Schedule as a metered account.

8. For display signs and signboard lighting, where hours of use are controlled by timing devices, the following turn-on times will apply, unless BC Hydro otherwise agrees in writing:

Period	Turn-on Time
January 1 to January 15:	4:00 p.m.
January 16 to February 28:	4:30 p.m.
March 1 to April 30:	6:30 p.m.
May 1 to August 15:	8:30 p.m.
August 16 to September 30:	6:30 p.m.
October 1 to November 15:	4:30 p.m.
November 16 to December 31:	4:00 p.m.

9. In all cases, where hours of use of display signs or signboard lighting commence at dusk and are controlled either by timing devices or by photo-electric cells, the following hours of use for a period of two months will be deemed for billing purposes:

Dusk to 10 p.m.:	216 hours
Dusk to 11 p.m.:	270 hours
Dusk to 12 p.m.:	330 hours
Dusk to 1 a.m.:	380 hours
Dusk to Dawn:	666 hours

(All times are Pacific Time.)

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

	Migration Rules: 1. Migration rules from Small General Service: Customers taking Service under these Rate Schedules will be moved to Service: (a) Under Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) if Demand in half of the last six bi-monthly billing periods or half of the last 12 monthly billing periods (as applicable) was 35 kW or more, but less than 150 kW. (b) Under Rate Schedules 1600, 1601, 1610 or 1611 (Large General Service) if Demand in half of the last six bi-monthly billing periods or half of the last 12 monthly billing periods (as applicable) was 150 kW or more, or if total Energy consumption in any 12 consecutive month period exceeded 550,000 kWh. 2. Migration rules to Small General Service: Customers will be moved to Service under these Rate Schedules (Small General Service) from Rate Schedules 1600, 1601, 1610 or 1611 (Large General Service) or Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) if Billing Demand in each of the last 12 billing periods was less than 35 kW.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

2. GENERAL SERVICE

RATE SCHEDULES 1500, 1501, 1510, 1511 – MEDIUM GENERAL SERVICE (35 KW OR GREATER AND LESS THAN 150 KW)

Availability	For Customers who qualify for General Service and whose Billing Demand is equal to or greater than 35 kW but less than 150 kW, and whose Energy consumption in any 12-month period is equal to or less than 550,000 kWh. Supply is 60 hertz, single or three phase at Secondary or Primary Voltage. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone I.
Rate	**Basic Charge:** 26.56~~26.61~~ ¢ per day plus **Demand Charge:** $5.38~~5.39~~ per kW of Billing Demand plus **Energy Charge:** 9.62~~9.63~~ ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per Billing Period per kW of Billing Demand will be applied to the above charges if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

Monthly Minimum Charge	50% of the highest Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding 11 Billing Periods. For the purpose of this provision an on-peak period commences on November 1 in any year and terminates on March 31 of the following year.
Rate Schedules	1. Rate Schedule 1500: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1501: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1510: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1511: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Definitions	1. Billing Demand The Billing Demand will be the highest kW Demand in the Billing Period. 2. Billing Period A month between regular meter readings, provided that in cases where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.

ACCEPTED:______________________________

ORDER NO.______________________________ ______________________________
COMMISSION SECRETARY

Special Conditions	1. Metering Metering Equipment with both Demand and Energy measurement capability will normally be installed. Until such Metering Equipment is installed, or if the installed Metering Equipment does not have Demand measurement capability, Billing Demand will be as estimated by BC Hydro 2. Migration Rules 2.1. Migration rules from Medium General Service: Customers taking Service under these Rate Schedules (Medium General Service) will be moved to Service: (a) Under Rate Schedules 1300, 1301, 1310 or 1311 (Small General Service) if Billing Demand in each of the last 12 consecutive Billing Periods was less than 35 kW. (b) Under Rate Schedules 1600, 1601, 1610 or 1611 (Large General Service) if Billing Demand in half of the last 12 Billing Periods was 150 kW or more, or if total Energy consumption in any 12 consecutive month period exceeded 550,000 kWh.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

	2.2. Migration rules to Medium General Service: Customers will be moved to Service under these Rate Schedules (Medium General Service): (a) From Rate Schedules 1600, 1601, 1610 or 1611 (Large General Service) if Billing Demand in each of the last 12 Billing Periods was 35 kW or more, but less than 100 kW, and Energy consumption during the same period was less than 400,000 kWh. (b) From Rate Schedules 1300, 1301, 1310 or 1311 (Small General Service) if Billing Demand in half of the last six bi-monthly Billing Periods or half of the last 12 monthly Billing Periods (as applicable) was 35 kW or more, but less than 150 kW, and total Energy consumption in the same period was less than 550,000 kWh.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULES 1600, 1601, 1610, 1611 – LARGE GENERAL SERVICE (150 KW AND OVER)

Availability	For Customers who qualify for General Service and whose Billing Demand is equal to or greater than 150 kW, or whose Energy consumption in any 12 month period is greater than 550,000 kWh. Supply is 60 hertz, single or three phase at Secondary or Primary Voltage. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone I.
Rate	**Basic Charge:** 26.56~~26.61~~ ¢ per day plus **Demand Charge:** $12.26~~12.28~~ per kW of Billing Demand plus **Energy Charge:** 6.02~~6.03~~ ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per Billing Period per kW of Billing Demand will be applied to the above charges if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

Monthly Minimum Charge	50% of the highest Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding 11 Billing Periods. For the purpose of this provision an on-peak period commences on November 1 in any year and terminates on March 31 of the following year.
Rate Schedules	1. Rate Schedule 1600: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1601: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1610: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1611: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Definitions	1. Billing Demand The Billing Demand will be the highest kW Demand in the Billing Period. 2. Billing Period A month between regular meter readings, provided that where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

Special Conditions	1. Metering Metering Equipment with both Demand and Energy measurement capability will normally be installed. Until such Metering Equipment is installed, or if the installed Metering Equipment does not have Demand measurement capability, Billing Demand will be as estimated by BC Hydro. 2. Migration Rules 2.1. Migration rules from Large General Service: Customers taking Service under these Rate Schedules (Large General Service) will be moved to Service: (a) Under Rate Schedules 1300, 1301, 1310 or 1311 (Small General Service) if Billing Demand in each of the last 12 consecutive Billing Periods was less than 35 kW. (b) Under Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) if Billing Demand in each of the last 12 consecutive Billing Periods was 35 kW or more but less than 100 kW, and Energy consumption in the same period was less than 400,000 kWh. 2.2. Migration rules to Large General Service: Customers will be moved to Service under these Rate Schedules (Large General Service) from Rate Schedules 1300, 1301, 1310 or 1311 (Small General Service) or Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) if Billing Demand in half of the last six bi-monthly Billing Periods or half of the last 12 monthly Billing Periods (as applicable) was 150 kW or more, or if total Energy consumption in any 12 consecutive month period exceeded 550,000 kWh.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.

ACCEPTED:____________________

ORDER NO.____________________

____
COMMISSION SECRETARY

~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

2. GENERAL SERVICE

RATE SCHEDULES 1640, 1641, 1642, 1643 – OVERNIGHT RATE (150 KW AND OVER)

Availability	For Customers who qualify for General Service where the Customer is a business, government agency or other organization. For use only for separately metered charging of Electric Fleet Vehicles or Vessels owned or leased by, and operated by, the Customer, at Maximum Demand equal to or greater than 150 kW. Supply is 60 hertz, single or three phase at Secondary or Primary Voltage. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone 1.
Rate	**Basic Charge:** 26.56~~26.61~~ ¢ per day plus **Demand Charge:** $12.26~~12.28~~ per kW of Billing Demand per Billing Period plus **Energy Charge:** 7.41 ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per Billing Period per kW of Billing Demand will be applied to the above charges if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.

ACCEPTED:____________________________

ORDER NO.____________________________ ____________________________

COMMISSION SECRETARY

Monthly Minimum Charge	50% of the highest Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding 11 Billing Periods. For the purpose of this provision an on-peak period commences on November 1 in any year and terminates on March 31 of the following year.
Rate Schedules	1. Rate Schedule 1640: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1641: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1642: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1643: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Definitions	1. Billing Demand The Billing Demand will be the highest kW Demand between the hours 06:00 and 22:00 daily in the Billing Period. Notwithstanding the foregoing, the Billing Demand will be the highest kW Demand in the Billing Period for the purposes of determining: (i) any discount under this Rate Schedule for Customer supplied Transformation; and (ii) BC Hydro's contribution towards an Extension under section 8.3 (Extension Fee for Rate Zone I).

	2. Billing Period A month between regular meter readings, provided that where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period. 3. Electric Fleet Vehicle or Vessel A Vehicle or Vessel that: (a) Is powered entirely or partially by electricity; and (b) Is part of a group of similar Vehicles or Vessels that are used for similar purposes. 4. Vehicle A vehicle used for transportation, not run on rails, and includes, without limitation, buses, medium duty trucks and heavy duty trucks. 5. Vessel A watercraft used for transportation and includes, without limitation, passenger and vehicle ferries, tugs and barge transportation.
Special Conditions	1. Metering Metering Equipment with both Demand and Energy measurement capability will be installed. Only charging of Electric Fleet Vehicles or Vessels and related equipment will be served under these Rate Schedules. 2. Migration Customers taking service under these Rate Schedules will not be migrated to Rate Schedules 1300, 1301, 1310, or 1311 (Small General Service) or Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) due to changes in load size. BC Hydro will review this Special Condition in its evaluation report planned for the third year after which the rate commences.

	3. Concurrent Service under other Rate Schedules BC Hydro will not provide service to equipment installed for service under these Rate Schedules under any other rate schedule except Rate Schedule 1901.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:____________________________

ORDER NO.____________________________

____
COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULES 1650, 1651, 1652, 1653 – DEMAND TRANSITION RATE (150 KW AND OVER)

Availability	For Customers who qualify for General Service where the Customer is a business, government agency or other organization. For use only for separately metered charging of Electric Fleet Vehicles or Vessels owned or leased by, and operated by, the Customer, at Maximum Demand equal to or greater than 150 kW. Supply is 60 hertz, single or three phase at Secondary or Primary Voltage. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone 1.
Termination Date	These Rate Schedules will terminate effective March 31, 2032. As of April 1, 2032 customers will be migrated to Rate Schedules 16xx or the otherwise applicable rate.
Rate	**Basic Charge:** 26.56~~26.61~~ ¢ per day plus **Demand Charge:** \$0 per kW of Billing Demand until March 31, 2026 plus **Energy Charge:** 9.12~~9.13~~ ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per Billing Period per kW of Billing Demand will be applied to the above charges if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

Monthly Minimum Charge	50% of the highest Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding 11 Billing Periods. For the purpose of this provision an on-peak period commences on November 1 in any year and terminates on March 31 of the following year.
Rate Schedules	1. Rate Schedule 1650: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1651: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1652: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1653: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Definitions	1. Billing Demand The Billing Demand will be the highest kW Demand in the Billing Period. 2. Billing Period A month between regular meter readings, provided that where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.

3. Electric Fleet Vehicle or Vessel

   A Vehicle or Vessel that:

   (a) Is powered entirely or partially by electricity; and

   (b) Is part of a group of similar vehicles or Vessels that are used for similar purposes.

4. Vehicle

   A vehicle used for transportation, not run on rails, and includes, without limitation, buses, medium duty trucks and heavy duty trucks.

5. Vessel

   A watercraft used for transportation and includes, without limitation, passenger and vehicle ferries, tugs and barge transportation.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

Special Conditions	1. Demand and Energy Charge Pricing The Demand and Energy Charge Pricing over the period that these Rate Schedules are in effect is provided in the following table. No Demand Charge shall apply to Customers receiving service under these Rate Schedules for the first six years of the rate, from April 1, 2020 to March 31, 2026. As of April 1, 2026 the Demand Charge will be transitioned to the Rate Schedules 1600, 1601, 1610 and 1611 (Large General Service) Demand Charge over six years and completed by March 31, 2032, unless otherwise authorized by the Commission. The Energy Charge will be subject to general rate increases during the period of April 1, 2020 to March 31, 2026. As of April 1, 2026 the Energy Charge will be transitioned to the Rate Schedules 1600, 1601, 1610 and 1611 (Large General Service) Energy Charge over six years, to March 31, 2032, unless otherwise authorized by the Commission.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

		Effective Date	Fiscal Year	Demand Charge	Energy Charge
		April 1, 2020	F2021	$0	9.03 ¢ per kWh
		April 1, 2021	F2022	$0	9.13 ¢ per kWh
		April 1, 2022	F2023	$0	F2022 Energy Charge x RRA increase
		April 1, 2023	F2024	$0	F2023 Energy Charge x RRA increase
		April 1, 2024	F2025	$0	F2024 Energy Charge x RRA increase
		April 1, 2025	F2026	$0	F2025 Energy Charge x RRA increase
		April 1, 2026	F2027	F2026 Demand Charge + [F2027 LGS Demand Charge ÷ 6]	F2026 Energy Charge + [F2027 LGS Energy Charge] ÷ 6
		April 1, 2027	F2028	F2027 Demand Charge + [F2028 LGS Demand Charge-F2027 Demand Charge] ÷ 5	F2027 Energy Charge + [F2028 LGS Energy Charge-F2027 Energy Charge] ÷ 5
		April 1, 2028	F2029	F2028 Demand Charge + [F2029 LGS Demand Charge-F2028 Demand Charge] ÷ 4	F2028 Energy Charge + [F2029 LGS Energy Charge-F2028 Energy Charge] ÷ 4
		April 1, 2029	F2030	F2029 Demand Charge + [F2030 LGS Demand Charge-F2029 Demand Charge] ÷ 3	F2029 Energy Charge + [F2030 LGS Energy Charge-F2029 Energy Charge] ÷ 3
		April 1, 2030	F2031	F2030 Demand Charge + [F2031 LGS Demand Charge-F2030 Demand Charge] ÷ 2	F2030 Energy Charge + [F2031 LGS Energy Charge-F2030 Energy Charge] ÷ 2
		April 1, 2031	F2032	F2032 LGS Demand Charge	F2032 LGS Energy Charge

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

	2. Metering Metering Equipment with both Demand and Energy measurement capability will be installed. Only charging of Electric Fleet Vehicles or Vessels and related equipment will be served under this rate schedule. 3. Migration Customers taking service under these Rate Schedules will not be migrated to Rate Schedules 1300, 1301, 1310, or 1311 (Small General Service) or Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) due to changes in load size. BC Hydro will review this Special Condition in its evaluation report planned for the third year after which the rate commences. 4. Concurrent Service under other Rate Schedules BC Hydro will not provide service to equipment installed for service under these Rate Schedules under any other rate schedule except Rate Schedule 1901.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

3. IRRIGATION SERVICE

RATE SCHEDULE 1401 – IRRIGATION SERVICE

Availability	For motor loads of 746 watts or more used for irrigation and outdoor sprinkling where Electricity will be used principally during the Irrigation Season as defined below. Supply is 60 hertz, single or three phase at the Secondary or Primary Voltage available. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone I and Rate Zone IB.
Rate	1. During the Irrigation Season: **Energy Charge:** 6.08~~6.09~~ ¢ per kWh **Minimum Charge:** $6.08~~6.09~~ per kilowatt of connected load per month for a period of eight months commencing in March in any year whether Energy consumption is registered or not. 2. During the Non-Irrigation Season: **Energy Charge:** First 150 kWh @ 6.08~~6.09~~ ¢ per kWh All additional kWh @ 48.21~~48.28~~ ¢ per kWh **Minimum Charge:** Where Energy consumption is 500 kWh or less, Nil. Where Energy consumption is more than 500 kWh, $48.63~~48.71~~ per kilowatt of connected load.
Discount for Ownership of Transformers	A discount of 25 ¢ per month per kW of connected load will be applied to the above charges if a Customer supplies the Transformation.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

Definitions	1. Irigation Season: In respect of each Service Connection the period commencing with a meter reading on or about March 1 in any year, having a mid-season meter reading on or about July 31, and ending with a meter reading on or about October 31 in that same year. BC Hydro may, in its discretion extend such period by postponing the termination date to any date not later than November 30, for the sole purpose of permitting a Customer to fill reservoirs necessary for the operation of the irrigation or sprinkling system. 2. Non-Irrigation Season: The period commencing at the end of one Irrigation Season and terminating at the beginning of the next Irrigation Season.
Special Conditions	1. No equipment provided with Electricity under this Rate Schedule will be served with Electricity under any other Rate Schedule while the Customer's Service Agreement under this Rate Schedule is in force. 2. Normally the Service Connection will be energized during the Non-Irrigation Season, but will be Disconnected if a Customer so requests. 3. The Minimum Charge during the Irrigation Season will commence in March for an account that has not been Terminated by the Customer, whether or not the Service Connection is energized and will be billed in two installments, at the end of July and at the end of October. 4. For the Irrigation Season, a bill will be rendered following the July and October meter readings. The first bill will be the greater of the Energy Charge and the Minimum Charge for the period March 1 to July 31. The second bill will be the greater of the Energy Charge for the season and the Minimum Charge for the season, less payment received for the first billing charges.

ACCEPTED:________________________

ORDER NO.________________________

COMMISSION SECRETARY

	5. For the Non-Irrigation Season a bill will be rendered following the March meter reading provided that there is registered Energy consumption. 6. If a motor is rated in horsepower, the conversion factor from horsepower to kilowatts will be: 1 horsepower = 0.746 kilowatts
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:______________________________

ORDER NO.______________________________

COMMISSION SECRETARY

4. STREET LIGHTING SERVICE

RATE SCHEDULE 1701 – OVERHEAD STREET LIGHTING

Availability	For lighting of public highways, streets and lanes in cases where BC Hydro owns, installs and maintains the fixtures, conductors, controls and poles.	
Applicable in	Any area served by suitable overhead distribution lines.	
Rate	Per fixture per month as set out below:	
	50 watt or less LED unit	$15.23~~15.25~~
	51 to 80 watt LED unit	$18.96~~18.99~~
	81 to 120 watt LED unit	$23.74~~23.77~~
	greater than 120 watt LED unit	$27.85~~27.89~~
	*100 watt H.P. sodium vapour unit	$19.47~~19.50~~
	*150 watt H.P. sodium vapour unit	$23.23~~23.27~~
	*200 watt H.P. sodium vapour unit	$26.82~~26.86~~
	*175 watt mercury vapour unit	$21.40~~21.44~~
	*250 watt mercury vapour unit	$24.66~~24.70~~
	*400 watt mercury vapour unit	$31.78~~31.84~~
	Wattages are unit wattages for LED and lamp watts for high pressure sodium vapour and mercury vapour.	
	* Note Special Condition No. 2.	
Special Conditions	1. Connection Charge No charge will be made for Service Connections.	

ACCEPTED:________________________

ORDER NO.________________________

COMMISSION SECRETARY

2. Mercury Vapour and High Pressure Sodium Vapour

   Mercury vapour fixtures and high pressure sodium vapour fixtures are not available for new installations.

3. Extension Policy

   BC Hydro will construct a distribution Extension if required by the applicant in accordance with the Terms and Conditions of the Electric Tariff as applicable.

   When, at the Customer's request, a new fixture replaces an existing fixture, the Customer will pay to BC Hydro the original cost of the existing fixture, less any accumulated depreciation, and the cost of removing the existing fixture.

4. Relocation and Redirection of Fixtures

   The Customer will pay the full cost of relocating or redirecting fixtures when the change is made at the request of the Customer.

5. Design

   BC Hydro will design the installation of overhead street lighting fixtures.

6. Street Lights Failing to Operate

   BC Hydro will, without charge, replace street lights or components that fail to operate, unless breakage is the reason for such failure in which case the Customer will be charged the cost of the material required to make the fixture operate.

7. Term of Service Agreement

   The term of the initial Service Agreement under this Rate Schedule will be not more than five years; renewal periods will be for five years.

Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Supplemental Charge	Effective May 1, 2021, a transition rate supplemental charge equal to $2.06 per fixture per month applies to all street lights billed under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding. Effective May 1, 2021 this Rate Schedule includes an interim supplemental charge.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

4. STREET LIGHTING SERVICE

RATE SCHEDULE 1702 – PUBLIC AREA ORNAMENTAL STREET LIGHTING

Availability	For lighting of public highways, streets and lanes and municipal pathways and for public area seasonal lighting displays, in those cases where the Customer owns, installs and maintains the standards, fixtures, conductors and controls.
Applicable in	All Rate Zones.
Rate	**Energy Charge:** For each unmetered fixture: 3.75 ¢ per watt of Billing Wattage per month For each metered fixture: 11.25~~11.27~~ ¢ per kWh
Definitions	Billable Wattage is the sum of all wattage, on all fixtures used by the Customer. For fixtures without dimming controls, the watts per fixture will include the wattage of the lamp plus, where applicable, the wattage of the ballast. For fixtures with dimming controls, the watts per fixture will be equal to: 1. The wattage of the lamp plus, where applicable, the wattage of the ballast, multiplied by 2. The ratio of effective fixture wattage after dimming to fixture wattage before dimming.

ACCEPTED:______________________________

ORDER NO.______________________________ ______________________________
COMMISSION SECRETARY

Special Conditions	1. Service Connection Where necessary BC Hydro will provide an overhead or underground Service Connection in accordance with the Terms and Conditions of the Electric Tariff. No Service Connection will be made to add any ornamental street lighting system which does not provide for eight or more street lighting fixtures except that, if the potential is 120/240 volts, at BC Hydro's discretion, a Service Connection may be made for a system of less than eight. Receptacle loads will be permitted for Service under this Rate Schedule provided that such receptacles are used predominantly for seasonal lighting displays, meaning that no more than 10% of the usage may be for other purposes. 2. Extension Policy BC Hydro will construct a distribution Extension if required by the applicant in accordance with the Terms and Conditions of the Electric Tariff. 3. Power Factor All installations of mercury vapour, sodium vapour or fluorescent lamps will be equipped with the necessary auxiliaries to assure that a Power Factor of not less than 90% lagging will be maintained. 4. Term of Service Agreement The term of the initial Service Agreement under this Rate Schedule will be not more than five years; renewal periods will be for five years.

5. Fixtures with Automated Dimming Controls

The following special terms and conditions apply to lighting fixtures fitted with dimming controls:

(a) For purposes of this Special Condition No. 5, "dimming controls" means control units or fittings attached to, or forming part of, a street lighting fixture capable of being programmed or remotely operated so as to reduce the lumens output of the lamps during specified hours each day while the lamps are in operation. The reductions may vary according to the hours of the day, the days of the week, and the seasons of the year.

(b) A Customer wishing to have fixtures with dimming controls separately rated under this Rate Schedule must submit a dimming schedule satisfactory to BC Hydro listing each light fixture fitted with dimming controls, the wattage of the fixture (including the lamp and, where applicable, the ballast), the dimming control setting or settings and the hours each day that the dimming control setting or settings will be in operation.

(c) Whenever the Customer wishes to make changes in the lighting fixtures listed in the dimming schedule or in the dimming control settings or hours of operation, the Customer will submit an updated lighting fixture schedule to BC Hydro listing any changes. Changes will be permitted on a semi-annual basis (twice per year).

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

	6. Unmetered Service (a) BC Hydro may permit unmetered Service under this Rate Schedule if it can estimate to its satisfaction the Energy used in kilowatt hours over a period of one month based on the connected load and hours of use. (b) The Customer will notify BC Hydro immediately of any proposed or actual change in load, or load characteristics, or hours of use. (c) BC Hydro, in its discretion, may at any time install Metering Equipment and thereafter bill the Customer on the Energy consumption registered.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

4. STREET LIGHTING SERVICE

RATE SCHEDULE 1703 – STREET LIGHTING SERVICE

Availability	For lighting of public highways, streets and lanes in those cases where the Customer owns, installs and maintains the fixtures, conductors and controls on poles of BC Hydro. Available only to Customers formerly taking Service on Rate Schedule 1755, 1756, 1757, 1758, 1759 or 1767, to the City of New Westminster in respect of a portion of D.L. 172, to the Municipality of Sparwood and to the City of Vancouver.
Applicable in	The Cities of Victoria and Prince Rupert, the Municipalities of Oak Bay, Esquimalt, Saanich and Central Saanich, the Village of Sidney, the unorganized areas of Port Renfrew and Shawnigan Lake, a portion of D.L. 172 in the City of New Westminster, Natal and the City of Vancouver.
Rate	**Energy Charge:** 3.75 ¢ per watt of Billing Wattage per month plus **Contact Charge:** $1.12 per contact per month The Contact Charge is a per fixture charge for the use of pole space.
Definitions	Billable Wattage is the sum of all wattage, on all fixtures used by the Customer. For fixtures without dimming controls, the watts per fixture will include the wattage of the lamp plus, where applicable, the wattage of the ballast. For fixtures with dimming controls, the watts per fixture will be equal to: 1. The wattage of the lamp plus, where applicable, the wattage of the ballast, multiplied by 2. The ratio of effective fixture wattage after dimming to fixture wattage before dimming.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

Special Conditions	1. Extension Policy No Extension will be made to provide Service to street lights under this Rate Schedule. 2. Power Factor All installations of mercury vapour, sodium vapour or fluorescent lamps will be equipped with the necessary auxiliaries to assure that a Power Factor of not less than 90% lagging will be maintained. 3. Term of Service Agreement The term of the initial Service Agreement under this Rate Schedule will be not more than five years; renewal periods will be for five years. 4. Fixtures with Automated Dimming Controls The following special terms and conditions apply to lighting fixtures fitted with dimming controls: (a) For purposes of this Special Condition No. 4, “dimming controls” means control units or fittings attached to, or forming part of, a street lighting fixture capable of being programmed or remotely operated so as to reduce the lumens output of the lamps during specified hours each day while the lamps are in operation. The reductions may vary according to the hours of the day, the days of the week, and the seasons of the year. (b) A Customer wishing to have fixtures with dimming controls separately rated under this Rate Schedule must submit a dimming schedule satisfactory to BC Hydro listing each light fixture fitted with dimming controls, the wattage of the fixture (including the lamp and, where applicable, the ballast), the dimming control setting or settings and the hours each day that the dimming control setting or settings will be in operation.

	(c) Whenever the Customer wishes to make changes in the lighting fixtures listed in the dimming schedule or in the dimming control settings or hours of operation, the Customer will submit an updated lighting fixture schedule to BC Hydro listing any changes. Changes will be permitted on a semi-annual basis (twice per year).
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:______________________________

ORDER NO.______________________________ ______________________________
COMMISSION SECRETARY

4. STREET LIGHTING SERVICE

RATE SCHEDULE 1704 – TRAFFIC CONTROL EQUIPMENT

Availability	For lighting of traffic signals, traffic signs and traffic warning devices, and other equipment for controlling or directing vehicular or pedestrian traffic on public highways in those cases where the Customer owns, installs, and maintains the standards, fixtures, controls and associated equipment.
Applicable in	All Rate Zones.
Rate	**Energy Charge:** 11.25~~11.27~~ ¢ per kWh
Special Conditions	1. Service Connections Where necessary BC Hydro will provide an overhead or underground Service Connection in accordance with section 3 of the Terms and Conditions (Provision of Electricity). 2. Unmetered Service (a) BC Hydro may permit unmetered Service under this Rate Schedule if it can estimate to its satisfaction the Energy used in kilowatt hours over a period of one month based on the connected load and hours of use. (b) The Customer shall notify BC Hydro immediately of any proposed or actual change in load, or load characteristics, or hours of use. (c) BC Hydro, in its discretion, may at any time install a meter or meters and thereafter bill the Customer on the consumption registered.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

	3. Term of Service Agreement The term of the initial Service Agreement under this Rate Schedule will be not more than five years; renewal periods will be for five years.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rate under this Rate Schedule includes a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

4. STREET LIGHTING SERVICE

RATE SCHEDULE 1755 – PRIVATE OUTDOOR LIGHTING (CLOSED)

Availability	For outdoor lighting Service to illuminate property other than public streets or lanes (private property), where Service is provided from dusk to dawn and the supply is single phase, 60 hertz at the Secondary Voltage available. This Rate Schedule is available only in Premises served under this Rate Schedule on January 1, 1975 and only with respect to lights served under this Rate Schedule on January 1, 1975 and continuously thereafter, except BC Hydro may replace a mercury vapour unit with a high pressure sodium unit having approximately the same equivalent light output.
Applicable in	All Rate Zones.
Rate	**Charge per fixture per month as follows:** 1. Where a light is mounted on a pole that was installed by the Customer or by BC Hydro at the Customer's expense: 175 watt mercury vapour unit or replacement 100 watt H.P. sodium vapour unit — $18.25~~18.28~~ 400 watt mercury vapour unit or replacement 150 watt H.P. sodium vapour unit — $31.46~~31.51~~

	2. Where a light is mounted on a pole that is on public property, or an easement, and is part of BC Hydro's distribution system: 175 watt mercury vapour unit or replacement 100 watt H.P. sodium vapour unit — $19.38~~19.41~~ 400 watt mercury vapour unit or replacement 150 watt H.P. sodium vapour unit — $32.60~~32.65~~ 3. Where a light is mounted on a pole that was installed on the Customer's property by BC Hydro, at its expense, solely for the purpose of supporting the light: 175 watt mercury vapour unit or replacement 100 watt H.P. sodium vapour unit — $23.87~~23.90~~ 400 watt mercury vapour unit or replacement 150 watt H.P. sodium vapour unit — $37.57~~37.63~~ Except that if two or more lights are mounted at one time on the same pole the rates for the additional light or lights will be as set out under part 1 above.
Special Conditions	1. BC Hydro will provide and install: (a) An outdoor light consisting of luminaire, mast arm, ballast, lamp and photo-electric control, and (b) Not more than one span of overhead secondary conductors per light. 2. The Customer will be required to contribute the estimated cost of any plant required to make Secondary Voltage available at a point not more than one span from the light; such contribution is not subject to refund.

ACCEPTED:_________________________

ORDER NO._________________________

____
COMMISSION SECRETARY

	3. BC Hydro reserves the sole right to determine whether or not a light will be installed on a pole that is part of BC Hydro's distribution system. 4. The prior approval of BC Hydro is required if a Customer intends to install its own poles, and such poles will be maintained to BC Hydro's satisfaction at the Customer's expense. 5. BC Hydro will maintain all equipment owned by BC Hydro and will replace lamps which have failed. Any breakage will be repaired by BC Hydro at the Customer's expense.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:____________________________

ORDER NO.____________________________

COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1823 – TRANSMISSION SERVICE – STEPPED RATE

Availability	For all purposes. Supply is at 60 kV or higher. Customers supplied with Electricity under Rate Schedule 1825 (Time-of-Use) may only revert to Service under this Rate Schedule as permitted under Rate Schedule 1825.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Demand Charge:** $8.642~~8.655~~ per kVA of Billing Demand per Billing Period plus **Energy Charge: A** For new Customers and Customers that do not have a CBL by order of the British Columbia Utilities Commission: 5.065~~5.073~~ ¢ per kWh for all kWh per Billing Period This rate will apply until the Customer has been supplied with Electricity under this Rate Schedule for 12 Billing Periods or another period approved by the British Columbia Utilities Commission, after which the Customer will be supplied with Electricity at the rate specified in Part B below.

ACCEPTED:______________________________

ORDER NO.______________________________ ______________________________
COMMISSION SECRETARY

	Energy Charge: B For Customers with a CBL: 4.507~~4.514~~ ¢ per kWh applied to all kWh up to and including 90% of the Customer's CBL in each Billing Year 10.095~~10.111~~ ¢ per kWh applied to all kWh above 90% of the Customer's CBL in each Billing Year Note: Customers previously supplied with Electricity under Rate Schedule 1825 will be subject to the rates in Part B above from the time the Customer commences taking Service under this Rate Schedule. **Monthly Minimum Charge:** $8.642~~8.655~~ per kVA of Billing Demand
Definitions	1. Billing Year The Billing Year is the 12 month billing period starting with the first day of the Billing Period which commences nearest to April 1 in each year, and ending on the last day of such 12-month Billing Period.

2. Billing Demand

The Billing Demand will be:

(a) The highest kVA Demand during the High Load Hours (**HLH**) in the Billing Period; or

(b) 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or

(c) 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant,

whichever is the highest value, provided that for new Customers the Billing Demand for the initial two Billing Periods will be the average of the daily highest kVA Demands for the Customer's Plant.

	3. Customer Baseline Load (**CBL**) The Customer Baseline Load (**CBL**) is the Customer's historic annual energy consumption in kWh as approved by the British Columbia Utilities Commission. The Customer's CBL will initially be determined by BC Hydro, and be subject to revision from time to time, in accordance with the criteria and procedures set forth in BC Hydro's "Customer Baseline Load (**CBL**) Determination Guidelines" (Electric Tariff Supplement No. 74). All CBLs will be subject to final approval of the British Columbia Utilities Commission. 4. High Load Hours (**HLH**) High Load Hours (**HLH**) is the period of hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays (New Year's Day, Family Day, Good Friday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day). 5. Low Load Hours (**LLH**) Low Load Hours (**LLH**) are all hours other than HLH.
Special Conditions	1. A Customer having two or more operating plants may elect to have a single aggregated CBL determined for all or any combination of its operating plants in accordance with BC Hydro's "Customer Baseline Load (**CBL**) Determination Guidelines" (Electric Tariff Supplement No. 74). Thereafter, BC Hydro will issue a single bill for all operating plants included in the aggregation, and the Energy Charge payable will be determined on the basis of the aggregated CBL. However, the Demand Charge will continue to be determined separately for each operating plant.

ACCEPTED:________________________

ORDER NO.________________________ ________________________

COMMISSION SECRETARY

	2. If any initial, revised, or aggregate CBL for a Customer has not been determined by BC Hydro and approved by British Columbia Utilities Commission by the time at which the CBL would become effective, BC Hydro may determine the CBL on an interim basis and apply that CBL for the purposes of any billing periods and bills rendered to the Customer until such time as the CBL has been finally determined and approved by the British Columbia Utilities Commission, following which BC Hydro will make any necessary billing adjustments. 3. If a Customer taking Service at the rates in Part B of the Energy Charge rate section above Terminates Service under this Rate Schedule prior to the end of a Billing Year, the Customer's CBL or aggregate CBL will be prorated for the portion of the Billing Year during which the Customer was taking Service, and the prorated CBL or aggregate CBL will be used for the purposes of applying the rates in Part B to all energy consumption during the Billing Year up to the time of Termination. BC Hydro will make any necessary billing adjustments and bill the Customer for the difference (if any) owing.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Note	The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement Nos. 5 and 6, or Electric Tariff Supplement Nos. 87 and 88, as applicable.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1825 – TRANSMISSION SERVICE – TIME-OF-USE (TOU) RATE

Availability	For Customers who provide notice by February 15 of each year and who at the time of application are eligible to take Service under Rate Schedule 1823 (Stepped Rate) at the Energy Charge rates set out in Part B of the rate section of that Rate Schedule, and who have entered into a TOU (Transmission Service) Agreement by March 15 of that year. Customers will start Service under Rate Schedule 1825 in the first Billing Period after April 1.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Demand Charge:** $8.642~~8.655~~ per kVA of Billing Demand per Billing Period plus **Energy Charge:** 1. Winter HLH Period: 4.507~~4.514~~ ¢ per kWh applied to all kWh up to and including 90% of the Customer's Winter HLH Period CBL. 11.265~~11.282~~ ¢ per kWh applied to all kWh above 90% of the Customer's Winter HLH Period CBL. 2. Winter LLH Period: 4.507~~4.514~~ ¢ per kWh applied to all kWh up to and including 90% of the Customer's Winter LLH Period CBL. 10.210~~10.226~~ ¢ per kWh applied to all kWh above 90% of the Customer's Winter LLH Period CBL.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

	3. Spring Period: 4.507~~4.514~~ ¢ per kWh applied to all kWh up to and including 90% of the Customer's Spring Period CBL. 9.093~~9.107~~ ¢ per kWh applied to all kWh above 90% of the Customer's Spring Period CBL. 4. Remaining Period: 4.507~~4.514~~ ¢ per kWh applied to all kWh up to and including 90% of the Customer's Remaining Period CBL applicable. 9.971~~9.987~~ ¢ per kWh applied to all kWh above 90% of the Customer's Energy CBL applicable in the Billing Period.
Definitions	1. Billing Demand The Demand for billing purposes will be: (a) The highest kVA Demand during the High Load Hours (**HLH**) in the Billing Period; or (b) 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or (c) 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant, whichever is the highest value.

2. Customer Baseline Load (CBL)

The Customer Baseline Load (**CBL**) is the Customer's historic consumption (in kWh) as approved by the British Columbia Utilities Commission. For the purposes of this Rate Schedule, the Customer's CBL will consist of four separate CBLs – one each for the Winter HLH Period, the Winter LLH Period, the Spring Period and the Remaining Period. The Customer's CBL will initially be determined by BC Hydro, and be subject to revision from time to time, in accordance with the criteria and procedures set forth in BC Hydro's "Customer Baseline Load (**CBL**) Determination Guidelines" (Electric Tariff Supplement No. 74). All CBLs will be subject to final approval of the British Columbia Utilities Commission.

3. High Load Hours (**HLH**)

High Load Hours (**HLH**) is the period of hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays (New Year's Day, Family Day, Good Friday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day).

4. Low Load Hours (**LLH**)

The Low Load Hours (**LLH**) are all hours other than HLH.

5. Remaining Period

The Remaining Period is all Billing Periods other than the Winter Period or the Spring Period.

6. Spring Period

The Spring Period comprises the two Billing Periods starting with the first day of the Billing Period that commences nearest to May 1 each year and ending on the last day of the second Billing Period thereafter.

	7. Winter Period The Winter Period comprises four Billing Periods starting with the first day of the Billing Period that commences nearest to November 1 each year and ending on the last day of the fourth Billing Period thereafter.
Special Conditions	1. Service under this Rate Schedule will be provided only while a TOU (Transmission Service) Agreement with the Customer is in effect. 2. A Customer having two or more operating plants may elect to have a single aggregated CBL determined for all or any combination of its operating plants in accordance with BC Hydro's "Customer Baseline Load (CBL) Determination Guidelines" (Electric Tariff Supplement No. 74). Separate Energy CBL values will be determined for each plant and then aggregated. BC Hydro will issue a single bill for all operating plants included in an aggregation, and the Energy Charge payable will be determined on the basis of the aggregated Energy CBL value. The Demand Charge will continue to be determined separately for each operating plant. 3. If any initial, revised, or aggregate CBL for a Customer has not been determined by BC Hydro and approved by British Columbia Utilities Commission by the time at which the CBL would become effective, BC Hydro may determine the CBL on an interim basis and apply that CBL for the purposes of any billing periods and bills rendered to the Customer until such time as the CBL has been finally determined and approved by the British Columbia Utilities Commission, following which BC Hydro will make any necessary billing adjustments.

	4. In accordance with the TOU (Transmission Service) Agreement, the Customer will have a period of 30 days following approval of the Customer's initial CBL by the British Columbia Utilities Commission within which the Customer may, by written notice to BC Hydro, withdraw from taking Service under this Rate Schedule, and revert to taking Service under Rate Schedule 1823 (Stepped Rate). This right of withdrawal is available only when the Customer first subscribes to take Service under this Rate Schedule, and is applicable only in respect of the initial CBL determination. If the Customer exercises this right of withdrawal Rate Schedule 1823 will apply from the commencement of the then current Billing Year, and BC Hydro will make any necessary billing adjustments accordingly. 5. Customers taking Service under Rate Schedule 1852 (Modified Demand) may not also take Service under this Rate Schedule.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Note	The terms and conditions under which Transmission Service is supplied are contained in the Electricity Supply Agreement (Electric Tariff Supplement No. 5, or Electric Tariff Supplement No. 87, as applicable) as amended by the Electric Tariff Supplement No. 72 (TOU (Transmission Service) Agreement), and Electric Tariff Supplement No. 6, or Electric Tariff Supplement No. 88, as applicable.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

5. TRANSMISSION SERVICE

RATE SCHEDULE 1827 – TRANSMISSION SERVICE – RATE FOR EXEMPT CUSTOMERS

Availability	For all purposes. Supply is at 60 kV or higher. Only for City of New Westminster and University of British Columbia and other Customers exempted from Rate Schedule 1823 (Stepped Rate) by the British Columbia Utilities Commission.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Demand Charge:** $8.642~~8.655~~ per kVA of Billing Demand per Billing Period plus **Energy Charge:** 5.065~~5.073~~ ¢ per kWh for all kWh in a Billing Period **Monthly Minimum Charge:** $8.642~~8.655~~ per kVA of Billing Demand
Definitions	1. Billing Demand The Billing Demand will be: (a) The highest kVA Demand during the High Load Hours (**HLH**) in the Billing Period; or (b) 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or (c) 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant, whichever is the highest value.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

	2. High Load Hours (**HLH**) High Load Hours (**HLH**) is the period of hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays (New Year's Day, Family Day, Good Friday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day). 3. Low Load Hours (**LLH**) Low Load Hours (**LLH**) are all hours other than HLH.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Note	The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement Nos. 5 and 6, or Electric Tariff Supplements Nos. 87 and 88, as applicable.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1852 – TRANSMISSION SERVICE – MODIFIED DEMAND

Availability	To a Customer supplied with Electricity at 60 kV or higher who is taking Service under Rate Schedule 1823 (Stepped Rate) at the time of application, and is a party to a Modified Demand Agreement under Electric Tariff Supplement No. 54 which is in force, and which is in a location, as determined by BC Hydro, that will allow BC Hydro to curtail load to alleviate a potential local or regional transmission constraint, or take advantage of a market opportunity. The annual subscription period for new subscribers is from September 1 to October 31.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Excess Demand Charge:** $8.642~~8.655~~ per kVA of metered kVA Demand in excess of the Maximum Demand Level during Low Load Hours
Definitions	1. Billing Demand The Billing Demand will be: (a) The highest kVA Demand during the High Load Hours (**HLH**) in the Billing Period; or (b) 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or (c) 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant, whichever is the highest value.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

2. High Load Hours (**HLH**)

   High Load Hours (**HLH**) means the period(s) in a 24-hour day and during those days of a calendar week in which Electricity usage is typically highest in a particular region, as determined by BC Hydro in its discretion based on load characteristics and transmission constraints in that region from time to time, and designated in a Modified Demand Agreement.

3. Low Load Hours (**LLH**)

   Low Load Hours (**LLH**) are all hours other than HLH.

4. LLH CBL Energy

   LLH CBL Energy means the highest monthly energy consumption during the LLH over the last 12 Billing Periods, or an estimate of consumption if insufficient data is available.

5. Maximum Demand Level

   Maximum Demand Level has the meaning set out in the Modified Demand Agreement. For a Customer with more than one designated period of High Load Hours, separate Maximum Demand Levels will be stated for each corresponding period of Low Load Hours. For a Customer with a single designated period of High Load Hours, a single Maximum Demand Level will be stated for all Low Load Hours.

   The highest Maximum Demand Level will not exceed 95% of Contract Demand stated in the Customer's Electricity Supply Agreement, and is subject to local transmission availability.

Special Conditions	1. The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement Nos. 5 and 6. The provisions of Rate Schedule 1823 (Stepped Rate) and Electric Tariff Supplement Nos. 5 and 6 continue to apply to Customers receiving Service under this Rate Schedule. In the case of a conflict between this Rate Schedule or the Modified Demand Agreement and Rate Schedule 1823 or Electric Tariff Supplement Nos. 5 or 6, the provisions of this Rate Schedule and the Modified Demand Agreement will govern. 2. If for any two Billing Periods the total energy consumed under Rate Schedule 1852, during the LLH, is greater than the LLH CBL Energy by 10% or more, the highest kVA Demand in each such Billing Period during the High Load Hours will be adjusted by the ratio of the average monthly LLH Energy during such two Billing Periods over the LLH CBL Energy. The adjusted highest kVA Demand will apply for a period of 12 months after the second Billing Period included in the adjustment calculation. The LLH CBL Energy will be recalculated using the consumption history of the most recent 12 Billing Periods. 3. The Minimum Reduction under the Modified Demand Agreement will be the greater of 50% of the difference between the Maximum Demand Level and the LLH CBL Demand, and 10 MW. 4. The Maximum Number of Demand Reduction Transactions under the Modified Demand Agreement will be the greater of Maximum Duration multiplied by the Maximum Number of Demand Reduction Transactions, and 48 hours.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

~~Interim~~ Rate Increase	Effective April 1, 2021 the rate under this Rate Schedule includes a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:______________________________

ORDER NO.______________________________

COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1853 – TRANSMISSION SERVICE – IPP STATION SERVICE

Availability	For Customers who are Independent Power Producers (**IPPs**) served at transmission voltage, on an interruptible basis.
Applicable in	Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Energy Charge:** The sum, over the Billing Period, of the hourly energy consumed multiplied by the entry in the Intercontinental Exchange (**ICE**) Mid-Columbia (Mid-C) Peak, and Mid-C Off-Peak weighted average index price as published by the ICE in the ICE Day Ahead Power Price Report that corresponds to the time when consumption occurred, during that hour
Monthly Minimum Charge	$48.70~~48.78~~
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. 2. BC Hydro may, without notice to the Customer, refuse to supply or terminate the supply of Electricity under this Rate Schedule if at any time BC Hydro does not have sufficient energy or capacity. 3. Prior to taking Electricity under this Rate Schedule, the Customer may be required to obtain approval from BC Hydro. BC Hydro will advise the Customer of the need to obtain approval prior to the taking of Electricity under this Rate Schedule. 4. Electricity taken under this Rate Schedule is to be used solely for maintenance and black-start requirements and will not displace electricity that would normally be generated by the Customer.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

Taxes	The rates and Monthly Minimum Charge set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the Monthly Minimum Charge under this Rate Schedule includes a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

5. TRANSMISSION SERVICE

RATE SCHEDULE 1880 – TRANSMISSION SERVICE – STANDBY AND MAINTENANCE SUPPLY

Availability	For Customers supplied with Electricity under Rate Schedule 1823 (Stepped Rate), 1825 (TOU Rate), 1827 (Rate for Exempt Customers), 1828 (Biomass Energy Program) or 1852 (Modified Demand), on an interruptible basis.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Administrative Charge:** $150.00 per Period of Use plus **Energy Charge:** During the Period of Use, 10.095~~10.111~~ ¢ per kWh of metered Rate Schedule 1880 energy consumption, determined as set out below
Definitions	1. HLH Reference Demand HLH Reference Demand is the highest kVA Demand in the HLH for the current Billing Period prior to the Period of Use, but excluding any prior Period of Use. If the Period of Use extends over an entire Billing Period, the highest kVA Demand in the HLH from the prior Billing Period will be used in determining the HLH Reference Demand, excluding any Period of Use in the prior Billing Period. For the purpose of determining HLH Reference Demand, the HLH periods are as defined in Rate Schedule 1823, 1825, 1827, 1828 or 1852, whichever is applicable.

ACCEPTED:__________________________

ORDER NO.__________________________

____
COMMISSION SECRETARY

	2. Period of Use A period of consecutive hours during which Electricity is taken under this Rate Schedule. The Period of Use is as defined by the Customer when requesting Service from BC Hydro under this Rate Schedule 1880 and may extend into subsequent Billing Periods.
Rate Schedule 1880 Energy Determination	During HLH periods, the kWh consumption on an hourly basis which exceeds the HLH high kWh per hour within the Period of Use or portion thereof where HLH high kWh per hour is the product of HLH Reference Demand multiplied by the Power Factor for the half hour when the HLH Reference Demand occurred. For the purpose of the Rate Schedule 1880 Energy Determination, the HLH periods are as defined in Rate Schedule 1823, 1825, 1827, 1828 or 1852, whichever is applicable.
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. 2. BC Hydro may, without notice to the Customer, refuse to supply or terminate the supply of Electricity under this Rate Schedule if at any time during the Period of Use BC Hydro does not have sufficient energy or capacity.

3. This Rate Schedule is only for the following purposes:

   To provide Electricity the Customer would otherwise generate during periods when all or part of the Customer's electrical generating plant is curtailed.

   Electricity used for this purpose may be taken on an instantaneous basis when the impact of the instantaneous pickup of loads normally provided by the Customer's electrical generation units does not occur after BC Hydro has advised the Customer that a period of system constraint or potential system constraint exists.

   During periods of potential system constraints, BC Hydro will require Customers to arm load shedding relays to ensure that the loss of electricity production from a Customer's electrical generation unit will not result in a demand greater than the Customer's Maximum kVA Demand on BC Hydro's system. BC Hydro may require the Customer to provide it with control of these load shedding relays. During periods of potential system constraints, upon a Customer's request, BC Hydro will endeavour to provide Electricity normally provided by the Customer's electrical generation unit.

   The Customer is required to advise BC Hydro within 30 minutes of taking Electricity under this Rate Schedule for this purpose. If the Customer fails to advise BC Hydro within 30 minutes, measured Demand and Energy consumption will be billed under Rate Schedule 1823, 1825, 1827, 1828 or 1852, whichever is applicable.

4. Electricity taken under this Rate Schedule will not displace Electricity otherwise to be taken by the Customer under Rate Schedule 1823, 1825, 1827, 1828 or 1852.

   Electricity taken under this Rate Schedule will not displace electricity that would normally be generated by the Customer for the purpose of re-sale.

ACCEPTED:____________________

ORDER NO.____________________

COMMISSION SECRETARY

	5. In addition to the charges specifically set out in this Rate Schedule, the Customer will pay for any additional facilities required to deliver Electricity under this Rate Schedule provided that BC Hydro obtains the prior consent of the Customer for construction of the additional facilities. 6. A Customer may be required to allow BC Hydro to install metering and communication equipment to measure the electricity output of the Customer's self-generation unit. 7. BC Hydro will bill for Electricity taken under Rate Schedule 1880 at the same time it bills for Electricity taken under Rate Schedule 1823, 1825, 1827, 1828 or 1852, whichever is applicable.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Note	The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement Nos. 5 and 6, or Electric Tariff Supplement Nos. 87 and 88, as applicable.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
~~Interim~~ Rate Increase	Effective April 1, 2021 the Energy Charge under this Rate Schedule includes a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ACCEPTED:______________________________

ORDER NO.______________________________ ______________________________
COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1891 – TRANSMISSION SERVICE – SHORE POWER SERVICE

Availability	For the supply of Shore Power to Port Customers for use by Eligible Vessels while docked at the Port Customer's Port Facility, on an interruptible basis. Supply is at 60 kV or higher.
Applicable in	Rate Zone I.
Rate	**Administrative Charge:** \$150.00 per month plus **Energy Charge:** 10.095~~10.111~~ ¢ per kWh for all kWh in a billing period
Definitions	For purposes of this Rate Schedule, capitalized terms have the meanings given to them in the Shore Power Service Agreement (Electric Tariff Supplement No. 86).
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. BC Hydro may refuse Service under this Rate Schedule in circumstances where BC Hydro does not have sufficient energy or capacity. For greater certainty, BC Hydro will not be required to construct a System Reinforcement under Electric Tariff Supplement No. 6 to provide Shore Power Service under this Rate Schedule. 2. The terms and conditions under which Shore Power Service is supplied are contained in the Shore Power Service Agreement (Electric Tariff Supplement No. 86). The Port Customer will pay to BC Hydro the charges set out in this Rate Schedule in addition to any charges set out in the Shore Power Service Agreement.

	3. A Port Customer that provides Port Electricity at a Port Facility under Rate Schedules 1600, 1601, 1610, 1611 (Large General Service) or 1823 (Stepped Rate) is not eligible to take Shore Power Service under this Rate Schedule to provide Port Electricity to that Port Facility, or a Port Facility served by the same BC Hydro delivery facilities. 4. On each occasion, if any, that BC Hydro is required to dispatch power line technicians or other workers to operate the switchgear for each connect and disconnect of Eligible Vessels docked at the Port Customer's Port Facility, BC Hydro will charge, and the Port Customer will pay, the reasonable time and labour costs for this service. The charge will be based on prevailing BC Hydro contracted labour rates and will be separately itemized on the Port Customer's monthly bill.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

5. TRANSMISSION SERVICE

RATE SCHEDULE 3808 – TRANSMISSION SERVICE – FORTISBC INC.

Availability	This Rate Schedule is available to FortisBC Inc. (FortisBC) in accordance with the terms and conditions of the Agreement between BC Hydro and FortisBC entered into and deemed effective July 1, 2014 (Power Purchase Agreement). Contract Demand must not exceed 200 MW in any hour.
Applicable in	For Electricity delivered to FortisBC at each Point of Delivery as defined in the Power Purchase Agreement.
Rate	**Demand Charge:** $8.642~~8.655~~ per kW of Billing Demand per Billing Month plus **Energy Charge:** Tranche 1 Energy Price: 5.065~~5.073~~ ¢ per kWh Tranche 2 Energy Price: 9.509 ¢ per kWh

ACCEPTED:______________________________

ORDER NO.______________________________ ______________________________
COMMISSION SECRETARY

Definitions	1. Billing Demand The Billing Demand in any Billing Month will be the greatest of: (a) The maximum amount of Electricity (in kW) scheduled under the Power Purchase Agreement, for any hour of the Billing Month; (b) 75% of the maximum amount of Electricity (in kW) scheduled under the Power Purchase Agreement in any hour in the 11 months of the Term immediately prior to the Billing Month (or less than 11 months, if the Effective Date is less than 11 months prior to the month); and (c) 50% of the Contract Demand (in kW) for the Billing Month. If FortisBC has reduced the Contract Demand in accordance with the Power Purchase Agreement, the amount of Electricity specified in item (b) above may not exceed an amount equal to 100% of the Contract Demand. 2. Maximum Tranche 1 Amount The Maximum Tranche 1 Amount for each Contract Year is 1,041 GWh. 3. Scheduled Energy Less Than or Equal to Annual Energy Nomination In any Contract Year, for the amount of the Scheduled Energy taken or deemed to be taken that is less than or equal to the Annual Energy Nomination, FortisBC will pay: (a) The Tranche 1 Energy Price for each kWh of such Scheduled Energy taken or deemed taken that is less than or equal to the Maximum Tranche 1 Amount; and (b) The Tranche 2 Energy Price for each kWh of such Scheduled Energy taken that exceeds the Maximum Tranche 1 Amount.

ACCEPTED:____________________________

ORDER NO.____________________________ ____________________________

COMMISSION SECRETARY

	4. Scheduled Energy Exceeding the Annual Energy Nomination In any Contract Year, for the amount of the Scheduled Energy taken or deemed to be taken that exceeds the Annual Energy Nomination, FortisBC will pay: (a) 150% of the Tranche 1 Energy Price, for each kWh of such Scheduled Energy taken or deemed taken that that exceeds the Annual Energy Nomination, but is less than or equal to the Maximum Tranche 1 Amount; and (b) 115% of the Tranche 2 Energy Price, for each kWh of such Scheduled Energy taken that exceeds the Annual Energy Nomination and also exceeds the Maximum Tranche 1 Amount. 5. Annual Minimum Take In any Contract Year, FortisBC will schedule and take an amount of Electricity equal to at least 75% of the Annual Energy Nomination, and will be responsible for any Annual Shortfall.
Note	The terms and conditions under which Service is supplied to FortisBC are contained in the Power Purchase Agreement.
Taxes	The rates and charges set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

~~Interim~~ Rate Increase	The Tranche 1 Energy Price and Demand Charge set out above are subject to the same rate adjustments as Rate Schedule 1827 (Rate for Exempt Customers). Tranche 2 Energy Price is subject to changes as provided for in the Power Purchase Agreement. Effective April 1, 2021 the Tranche 1 Energy Price and the Demand Charge under this Rate Schedule include a~~n~~ ~~interim~~ rate increase of 1.00~~1.16~~% before rounding.

ATTACHMENT H

Annual Transmission Revenue Requirement
for Network Integration Transmission Service

1. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be $978,303,960~~985,900,800~~.

2. The amount in (1) shall be effective until amended by the Transmission Provider or modified by the Commission.

Effective April 1, 2021, this ~~interim~~ rate schedule is approved.

ACCEPTED:__________________________

ORDER NO.__________________________

~~ACTING~~ COMMISSION SECRETARY

Schedule 00

Network Integration Transmission Service

Availability	For wholesale transmission of electricity.
Rate	Monthly Transmission Revenue Requirement: Customers will be charged their load ratio share of one twelfth (1/12th) of the Network Transmission Revenue Requirement per month. The Transmission Revenue Requirement is shown in Attachment H. One-twelfth of the Transmission Revenue Requirement is $81,525,330~~82,158,400~~.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Note	The terms and conditions under which Network Integration Transmission Service is supplied are contained in BC Hydro's OATT. Capitalized terms appearing in this Schedule, unless otherwise noted, shall have the meaning ascribed to them therein.

Effective April 1, 2021, this ~~interim~~ rate schedule is approved.

ACCEPTED:______________________________

ORDER NO.______________________________ ______________________________________

~~ACTING~~ COMMISSION SECRETARY

Schedule 01

Point-To-Point Transmission Service

Availability	For transmission of electricity on a firm and non-firm basis from one or more Point(s) of Receipt (POR) to one or more Point(s) of Delivery (POD).
Rate for Long-Term Firm Service	The Reserved Capacity Charge for the Long-Term Firm Service Rate will be up to a maximum price as set out below except where the POD is a point of interconnection between the Transmission System and the transmission system of FortisBC Inc., in which case the rate shall be zero ($0.00). The Maximum Reserved Capacity Charge is $78,262~~78,862~~/MW of reserved capacity per year to be invoiced monthly. Reserved Capacity Billing Demand The Reserved Capacity Billing Demand is determined for each POR(s), POD(s) pair. The Reserved Capacity for each pair of POR(s) and POD(s) will be the maximum non-coincident sum of the designated POR(s) and POD(s) included in the pair.

ACCEPTED:______________________________

ORDER NO.______________________________

____
~~ACTING~~ COMMISSION SECRETARY

Schedule 01 – Point-To-Point Transmission Service (continued)

Rate for Short-Term Firm and Non-Firm Service	The posted prices for Short-Term Firm and Non-Firm Service will be less than or equal to a maximum price ($/MWh) as set out below, except where the POD is a point of interconnection between the Transmission System and the transmission system of FortisBC Inc., in which case the rate shall be zero ($0.00). Maximum Price for: 1. Monthly delivery: $6,521.81~~6,571.79~~/MW of Reserved Capacity per month. 2. Weekly delivery: $1,505.03~~1,516.57~~/MW of Reserved Capacity per week. 3. Daily delivery: $214.42~~216.06~~/MW of Reserved Capacity per day. 4. Hourly delivery: $8.93~~9.00~~/MW of Reserved Capacity per hour. Discount Rate: For discounted paths posted on the Transmission Provider's OASIS, the Transmission Customer shall pay each month for Reserved Capacity Billing Demand the greater of the rates set forth below and the rate offered by the Transmission Customer and accepted by the Transmission Provider up to the maximum rate for Short-Term Firm and Non-Firm Service: 1. Hourly delivery: $3/MW of Reserved Capacity per hour in the Heavy Load Hour period (06:00-22:00, Monday - Saturday, excluding NERC holidays) and $1/MW of Reserved Capacity per hour for the Light Load Hour period (remaining hours and days). 2. Daily delivery: sum of the hourly delivery charge in the 24 hour period in the day.
Reserved Capacity for Short-Term Firm and Non-Firm Services	The Reserved Capacity shall be the maximum of the sum of non-coincident POD(s) Capacity Reservations or sum of non-coincident POR(s) Capacity Reservations.

ACCEPTED:________________________

ORDER NO.________________________

____
~~ACTING~~ COMMISSION SECRETARY

Schedule 01 – Point-To-Point Transmission Service (continued)

Penalty Charge	In addition to the applicable rate for service and associated charges for Ancillary Services, a penalty charge will be applied to all unauthorized usage at a rate of 125 percent of the maximum hourly delivery charge.
Special Conditions	Discounts: The following conditions apply to discounts for transmission service: 1. any offer of a discount made by BC Hydro must be announced to all Eligible Customers solely by posting on the OASIS, 2 any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, 3. once a discount is negotiated, details must be immediately posted on the OASIS, and 4. for any discount agreed upon for service on a path, from POR(s) POD(s), BC Hydro must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same POD(s) on the Transmission System.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Resales	The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff
Note	The terms and conditions under which Transmission Service is supplied are contained in BC hydro's Open Access Transmission Tariff. Capitalized terms appearing in this Rate Schedule, unless otherwise noted, shall have the meaning ascribed to them therein.

Effective April 1, 2021, this ~~interim~~ rate schedule is approved.

ACCEPTED:______________________________

ORDER NO.______________________________

____
~~ACTING~~ COMMISSION SECRETARY

Schedule 03

Scheduling, System Control, and Dispatch Service

Preamble	This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by BC Hydro. The Transmission Customer must purchase this service from BC Hydro. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below.
Availability	In support of Network Integration Transmission Service, Long and Short-Term Firm Point-to-Point Transmission Service, and Non-Firm Point-to-Point Transmission Service.
Rate	$0.152~~0.155~~ per MW of Reserved Capacity per hour.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Note	A description of the methodology for discounting Scheduling, System Control and Dispatch Services provided under this Schedule is contained in Section 3 of the BC Hydro OATT.

Effective April 1, 2021, this ~~interim~~ rate schedule is approved.

ACCEPTED:______________________________

ORDER NO.______________________________

____
~~ACTING~~ COMMISSION SECRETARY

1. RESIDENTIAL SERVICE

RATE SCHEDULES 1101, 1121 – RESIDENTIAL SERVICE

Availability	For Residential Service. Service is normally single phase, 60 hertz at the Secondary Voltage available. In BC Hydro's discretion, Service may be three phase 120/208 or 240 volts.
Applicable in	Rate Zone I.
Rate	1. Rate Schedule 1101 – Residential Service: **Basic Charge:** 20.77 ¢ per day plus **Energy Charge:** (a) For Customers billed monthly: Step 1: First 675 kWh per month@ 9.39 ¢/kWh Step 2: Additional kWh per month@ 14.08 ¢/kWh (b) For Customers billed bi-monthly: Step 1: First 1350 kWh per two months@ 9.39 ¢/kWh Step 2: Additional kWh per two months@ 14.08 ¢/kWh Note: For billing purposes, Step 1 is pro-rated on a daily basis. **Minimum Charge:** The Basic Charge

	2. Rate Schedule 1121 – Multiple Residential Service: **Basic Charge:** 20.77 ¢ per Dwelling per day plus **Energy Charge:** Per Dwelling (a) For Customers billed monthly: Step 1: First 675 kWh. per month@ 9.39 ¢/kWh Step 2: Additional kWh per month@ 14.08 ¢/kWh (b) For Customers billed bi-monthly: Step 1: First 1350 kWh per two months@ 9.39 ¢/kWh Step 2: Additional kWh per two months@ 14.08 ¢/kWh Note: For billing purposes, Step 1 is pro-rated on a daily basis. **Minimum Charge:** The Basic Charge per Dwelling
Discount for Ownership of Transformers	A discount of 25 ¢ per month per kW of Maximum Demand will be applied to amounts owing under Rate Schedule 1121 if the Customer supplies Transformation. BC Hydro will install Metering Equipment with both Demand and Energy measurement capability at the Secondary Voltage.
Special Conditions	1. The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under these Rate Schedules must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission. 2. Rate Schedule 1121 applies if the Premises contains more than two Dwellings.

ACCEPTED:________________________

ORDER NO.________________________

COMMISSION SECRETARY

Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a rate increase of 1.00% before rounding.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

1. RESIDENTIAL SERVICE

RATE SCHEDULE 1105 – RESIDENTIAL SERVICE – DUAL FUEL (CLOSED)

Availability	For residential space heating and water heating. Electricity purchased under this Rate Schedule will be separately metered. Service is single phase, 60 hertz, at 120/240 or 240 volts. This Rate Schedule is available only for Premises served under this Rate Schedule on January 15, 1990 and continuously thereafter and only in Premises where there has been no change in Customer since April 1, 2008.
Applicable in	Rate Zone I in areas where and when, in BC Hydro's opinion, BC Hydro's transmission, sub-transmission and distribution circuit feeders are or will be capable of handling the load.
Rate	**Energy Charge:** 8.58 ¢ per kWh
Special Conditions	1. Service under this Rate Schedule is not available to any Premises where Service was previously supplied and Terminated. 2. BC Hydro will upgrade an existing Service Connection supplying firm load to serve additional load in accordance with the Electric Tariff, however, no new or additional load is permitted under this Rate Schedule at any time. All unauthorized consumption of Electricity as estimated by BC Hydro will be billed at the rate for Electricity on the appropriate default Residential Service Rate Schedule. 3. The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under this Rate Schedule must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro’s advance written permission.

ACCEPTED:__________________________

ORDER NO.__________________________

COMMISSION SECRETARY

Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	The rate under this Rate Schedule is set in accordance with BCUC Order No. G-194-17. Effective April 1, 2021 a rate increase of 1.00% is applied.

ACCEPTED:______________________

ORDER NO.______________________ ______________________
COMMISSION SECRETARY

1. RESIDENTIAL SERVICE

RATE SCHEDULES 1107, 1127 – RESIDENTIAL SERVICE – ZONE II

Availability	For Residential Service. Service is normally single phase, 60 hertz at the Secondary Voltage available. In BC Hydro's discretion, Service may be three phase 120/208 or 240 volts.
Applicable in	Rate Zone II.
Rate	1. Rate Schedule 1107 – Residential Service: **Basic Charge:** 22.15 ¢ per day plus **Energy Charge:** First 1500 kWh per month @ 11.25 ¢ per kWh All additional kWh per month @ 19.32 ¢ per kWh **Minimum Charge:** The Basic Charge 2. Rate Schedule 1127 – Multiple Residential Service: **Basic Charge:** 22.15 ¢ per Dwelling per day plus **Energy Charge:** First 1500 kWh per Dwelling per month @ 11.25 ¢ per kWh All additional kWh per month @ 19.32 ¢ per kWh **Minimum Charge:** The Basic Charge per Dwelling

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

Discount for Ownership of Transformers	A discount of 25 ¢ per month per kW of Maximum Demand will be applied to amounts owing under Rate Schedule 1127 if the Customer supplies Transformation. BC Hydro will install Metering Equipment with both Demand and Energy measurement capability at the Secondary Voltage.
Special Conditions	1. The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under these Rate Schedules must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission. 2. Rate Schedule 1127 applies if the Premises contains more than two Dwellings.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a rate increase of 1.00% before rounding.

ACCEPTED:__________________________

ORDER NO.__________________________

____
COMMISSION SECRETARY

1. RESIDENTIAL SERVICE

RATE SCHEDULE 1148 – RESIDENTIAL SERVICE – ZONE II (CLOSED)

Availability	For Residential Service in Rate Zone II where a permanent electric space heating system is in use, providing such system was installed prior to October 10, 1966. This Rate Schedule is available only to a Customer and Premises served under this Rate Schedule on April 24, 1992 and continuously thereafter.
Applicable in	Rate Zone II.
Rate	**Basic Charge:** 22.15 ¢ per day plus **Energy Charge:** 11.25 ¢ per kWh **Minimum Charge:** The Basic Charge
Special Conditions	The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under this Rate Schedule must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a rate increase of 1.00% before rounding.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

1. RESIDENTIAL SERVICE

RATE SCHEDULES 1151, 1161 – EXEMPT RESIDENTIAL SERVICE

Availability	For Residential Service and uses exempted from Rate Schedules 1101 and 1121 (Residential Service), including: 1. Use on farms as set out in the definition of Residential Service in the Terms and Conditions; and 2. Use in Rate Zone IB. Service is normally single phase, 60 hertz at the Secondary Voltage available. In BC Hydro's discretion, Service may be three phase 120/208 or 240 volts.
Applicable in	Rate Zone I and Rate Zone IB.
Rate	1. Rate Schedule 1151 – Residential Service: **Basic Charge:** 22.15 ¢ per day plus **Energy Charge:** 11.25 ¢ per kWh **Minimum Charge:** The Basic Charge 2. Rate Schedule 1161 – Multiple Residential Service: **Basic Charge:** 22.15 ¢ per day per Dwelling per day plus **Energy Charge:** 11.25 ¢ per kWh **Minimum Charge:** The Basic Charge per Dwelling

ACCEPTED:________________________

ORDER NO.________________________

____
COMMISSION SECRETARY

Discount for Ownership of Transformers	A discount of 25 ¢ per month per kW of Maximum Demand will be applied to amounts owing under Rate Schedule 1161 if the Customer supplies Transformation. BC Hydro will install Metering Equipment with both Demand and Energy measurement capability at the Secondary Voltage.
Special Conditions	The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under these Rate Schedules must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a rate increase of 1.00% before rounding.

2. GENERAL SERVICE

RATE SCHEDULES 1200, 1201, 1210, 1211 – EXEMPT GENERAL SERVICE (35 KW AND OVER)

Availability	For Customers who qualify for General Service where supply is 60 hertz, single or three phase at Secondary or Primary Voltage and Billing Demand is 35 kW or more. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone IB.
Rate	**Basic Charge:** 26.56 ¢ per day plus **Demand Charge:** First 35 kW of Billing Demand per Billing Period @ \$0.00 per kW Next 115 kW of Billing Demand per Billing Period @ \$6.47 per kW All additional kW of Billing Demand per Billing Period @ \$12.41 per kW plus **Energy Charge:** First 14800 kWh of Energy consumption in the Billing Period @ 12.64 ¢ per kWh All additional kWh of Energy consumption in the Billing Period @ 6.07 ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per Billing Period per kW of Billing Demand will be applied to the above charges if a Customer supplies Transformation.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

	3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.
Monthly Minimum Charge	50% of the highest Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding 11 Billing Periods. For the purpose of this provision an on-peak period commences on November 1 in any year and terminates on March 31 of the following year.
Rate Schedules	1. Rate Schedule 1200: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1201: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1210: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1211: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Definitions	Billing Demand is the Maximum Demand in the Billing Period, subject to Special Condition No. 1. Billing Period means a month between regular meter readings, provided that in cases where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.

ACCEPTED:____________________

ORDER NO.____________________

COMMISSION SECRETARY

Special Conditions	1. Metering Equipment with both Demand and Energy measurement capability will normally be installed. Until such Metering Equipment is installed, or if the installed Metering Equipment does not have Demand measurement capability, Billing Demand will be as estimated by BC Hydro. 2. Migration rule: Customers taking Service under these Rate Schedules will be moved to Service under Rate Schedule 1300, 1301, 1310 or 1311 (Small General Service) if Billing Demand in each of the last 12 consecutive Billing Periods was less than 35 kW.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a rate increase of 1.00% before rounding.

2. GENERAL SERVICE

RATE SCHEDULES 1205, 1206, 1207 – GENERAL SERVICE – DUAL FUEL (CLOSED)

Availability	For general space heating, water heating and industrial process heating. Electricity purchased under these Rate Schedules will be separately metered. Service is 60 hertz single or three phase at the Secondary or Primary Voltage available. BC Hydro reserves the right to determine the voltage of the Service Connection. These Rate Schedules are available only for Premises served under these Rate Schedules on January 15, 1990 and continuously thereafter, only with respect to equipment served under these Rate Schedules on January 15, 1990 and continuously thereafter, and only in Premises where there has been no change in Customer since April 1, 2008.
Applicable in	Rate Zone I in areas where, in BC Hydro's opinion, BC Hydro's transmission, sub-transmission and distribution circuit feeders are or will be capable of handling the load.
Rate	Except as stated hereunder the rate will be: **Energy Charge:** First 8000 kWh per month @ 6.15 ¢ per kWh All additional kWh per month @ 4.02 ¢ per kWh
Rate Schedules	1. Rate Schedule 1205 – Small Commercial Applications: Applies to a Customer whose heating load is mostly in support of a commercial activity and whose firm Electricity is billed on a General Service (under 35 kW) Rate Schedule.

ACCEPTED:____________________

ORDER NO.____________________

COMMISSION SECRETARY

	2. Rate Schedule 1206 – Large Commercial Applications: Applies to a Customer whose heating load is mostly in support of a commercial activity and whose firm Electricity is billed on a General Service (35 kW and over) Rate Schedule. 3. Rate Schedule 1207 – Industrial Applications: Applies to a Customer whose heating load is mostly in support of an industrial activity and whose firm Electricity is billed on a General Service Rate Schedule or for farm use on a Residential Rate Schedule.
Special Conditions	1. Service under these Rate Schedules will not be available to any Premises beyond March 31, 2023. 2. These Rate Schedules are not available to Premises where Electricity under it was previously supplied and Terminated. 3. No other load than that stipulated in the Availability clause is permitted under these Rate Schedules. Any unauthorized use of Electricity or any refusal by a Customer to permit access to Premises in accordance with the Terms and Conditions of BC Hydro's Electric Tariff will result in immediate Termination under the applicable Rate Schedule and all unauthorized consumption as estimated by BC Hydro will be billed at the rate for Electricity on the appropriate default General Service Rate Schedule. 4. In addition to and without restriction of any other limitations of liability of BC Hydro, BC Hydro will specifically not be liable for any loss, damage, injury or expense occasioned to or suffered by any Customer receiving Service on these Rate Schedules, or by any other Person, for any reason whatsoever. 5. Replacement of existing heating equipment is allowed provided the rated capacity (equivalent kW) of the new equipment is not higher than the existing equipment. No new load or additional load is allowed

Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a rate increase of 1.00% before rounding.

ACCEPTED:__________________________

ORDER NO.__________________________

COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULE 1234 – SMALL GENERAL SERVICE (UNDER 35 KW) – ZONE II

Availability	For all purposes where a meter with Demand measurement capability is not installed because the Customer's Demand as estimated by BC Hydro is less than 35 kW. Supply is 60 hertz, single or three phase at an available Secondary Voltage.
Applicable in	Rate Zone II.
Rate	**Basic Charge:** 26.56 ¢ per day plus **Energy Charge:** First 7000 kWh per month @ 12.64 ¢ per kWh All additional kWh per month @ 21.04 ¢ per kWh **Minimum Charge:** The Basic Charge
Special Conditions	Special Conditions for Unmetered Service: 1. BC Hydro may permit unmetered Service under this Rate Schedule if it can estimate to its satisfaction the Energy used in kilowatt hours over a period of two months based on the connected load and the hours of use. 2. The Customer, if required by BC Hydro, will provide and maintain such controls, including timing devices, as BC Hydro considers necessary, and facilities satisfactory to BC Hydro for the maintenance of such controls. 3. The hours of use per period will be as specified by the Customer or as estimated by BC Hydro, whichever is greater.

ACCEPTED:____________________________

ORDER NO.____________________________

____
COMMISSION SECRETARY

4. The Customer will supply, install and maintain all wiring, fixtures, control devices and equipment, including the controls and devices described in Special Condition No. 2, at the expense of the Customer.

5. All wiring, fixtures, control devices and equipment and the method of installing, operating and maintaining the same are subject to the approval of BC Hydro which approval may be withdrawn by BC Hydro, at any time, at BC Hydro's sole discretion.

6. The Customer will notify BC Hydro immediately of any proposed or actual change in load, load characteristics, or hours of use.

7. BC Hydro may at any time, in its sole discretion, install Metering Equipment, and thereafter bill the Customer on the appropriate Rate Schedule as a metered account.

8. For display signs and signboard lighting, where hours of use are controlled by timing devices, the following turn-on times will apply, unless BC Hydro otherwise agrees in writing:

Period	Turn-on Time
January 1 to January 15:	4:00 p.m.
January 16 to February 28:	4:30 p.m.
March 1 to April 30:	6:30 p.m.
May 1 to August 15:	8:30 p.m.
August 16 to September 30:	6:30 p.m.
October 1 to November 15:	4:30 p.m.
November 16 to December 31:	4:00 p.m.

ACCEPTED:__________________________

ORDER NO.__________________________

COMMISSION SECRETARY

	9. In all cases, where hours of use of display signs or signboard lighting commence at dusk and are controlled either by timing devices or by photo-electric cells, the following hours of use for a period of two months will be deemed for billing purposes: Dusk to 10 p.m.: 216 hours Dusk to 11 p.m.: 270 hours Dusk to 12 p.m.: 330 hours Dusk to 1 a.m.: 380 hours Dusk to Dawn: 666 hours (All times are Pacific Time.)
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a rate increase of 1.00% before rounding.

ACCEPTED:

ORDER NO.

COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULE 1253 – DISTRIBUTION SERVICE – IPP STATION SERVICE

Availability	For Customers who are Independent Power Producers (**IPPs**) served at distribution voltage, on an interruptible basis.
Applicable in	Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Energy Charge:** The sum, over the billing period, of the hourly Energy consumed multiplied by the entry in the Intercontinental Exchange (**ICE**) Mid Columbia (Mid-C) Peak, and Mid-C Off-Peak weighted average index price as published by the ICE in the ICE Day Ahead Power Price Report that corresponds to the time when consumption occurred, during that hour.
Monthly Minimum Charge	$48.70
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. 2. BC Hydro may, without notice to the Customer, refuse to supply or terminate the supply of Electricity under this Rate Schedule if at any time BC Hydro does not have sufficient energy or capacity. 3. Prior to taking Electricity under this Rate Schedule, the Customer may be required to obtain approval from BC Hydro. BC Hydro will advise the Customer of the need to obtain approval prior to the taking of Electricity under this Rate Schedule. 4. Electricity taken under this Rate Schedule is to be used solely for maintenance and black-start requirements and will not displace electricity that would normally be generated by the Customer.

ACCEPTED:__________________________

ORDER NO.__________________________

COMMISSION SECRETARY

Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2021 the Monthly Minimum Charge under this Rate Schedule includes a rate increase of 1.00% before rounding.

ACCEPTED:____________________________

ORDER NO.____________________________

COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULES 1255, 1256, 1265, 1266 – GENERAL SERVICE (35 KW AND OVER) – ZONE II

Availability	For all purposes. Supply is 60 hertz, single or three phase at Secondary or Primary Voltage. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone II.
Rate	**Basic Charge:** 26.56 ¢ per day plus **Energy Charge:** First 200 kWh per kW of Billing Demand per month @ 12.64 ¢ per kWh All additional kWh per month @ 21.04 ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per month per kW of Billing Demand will be applied to the above rate if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts the discount for metering at a Primary Voltage will be applied first.
Monthly Minimum Charge	The monthly minimum charge to be paid by a Customer on Rate Schedule 1255, 1256, 1265 or 1266, as applicable, will be the charge the Customer would have been billed under Rate Schedule 1200, 1201, 1210 or 1211 (Exempt General Service – 35 kW and over), respectively.
Rate Schedules	1. Rate Schedule 1255: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation.

	2. Rate Schedule 1256: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1265: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1266: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Special Conditions	1. Metering Equipment with both Demand and Energy measurement capability will normally be installed. Until such Metering Equipment is installed, or if the installed Metering Equipment does not have Demand measurement capability, Billing Demand will be as estimated by BC Hydro. 2. Where the Customer's Demand is or is likely to be in excess of 45 kVA, BC Hydro may require such Customer to execute a special contract for Service, including such special conditions as BC Hydro, in its sole discretion considers necessary.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a rate increase of 1.00% before rounding.

ACCEPTED:____________________________

ORDER NO.____________________________

COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULE 1268 – DISTRIBUTION SERVICE – IPP DISTRIBUTION TRANSPORTATION ACCESS

Availability	For Customers who have generators connected to BC Hydro's distribution system and who want to access BC Hydro's transmission system pursuant to and in accordance with BC Hydro's Open Access Transmission Tariff (OATT).
Applicable in	Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Distribution Transportation Charge:** 0.196 ¢ per kWh
Special Conditions	1. The Customer is required to pay the costs, including the cost of altering existing facilities, to connect the generator to BC Hydro's distribution system in accordance with BC Hydro's Connection Requirements for Utility or Non-Utility Generation, 35 kV and Below. 2. For Customers with self-generation (i.e., with a Customer Baseline Load (**CBL**) greater than zero), this Rate Schedule is only applicable to sales of Surplus Energy. It may not be used by self-generating Customers who appear to have varied their demand for power from BC Hydro based on the actual or anticipated difference between BC Hydro's rate for providing Service to them and the market price of power. 3. For the purposes of this Rate Schedule, "Surplus Energy" in any period is the energy made available from generation by the Customer calculated as the difference between the Customer's CBL and the Customer's actual consumption from BC Hydro in that period.

ACCEPTED:______________________________

ORDER NO.______________________________ ______________________________

COMMISSION SECRETARY

	4. The Customer's CBL is established, in general, by determining the Customer's Energy consumption, on a monthly basis, for the past three years; in cases where inadequate history exists, alternative methods may be used to determine a Customer's CBL. Once established, the Customer's CBL will not be automatically adjusted for changes in the Customer's net metered consumption from BC Hydro. Any subsequent changes to the CBL must be due to changes in the Customer's load and not due to changes in its generation. The Customer must provide metered output from its generator which demonstrates an increase in generation output commensurate in time and amount with the Surplus Energy transported using this Rate Schedule. Where it appears that the Customer has transported on this Rate Schedule Energy that is not Surplus Energy, BC Hydro will provide replacement energy to the Customer's load at market prices, subject to Commission approval for such sales. 5. The metering point to determine the electricity being delivered to BC Hydro's distribution system will be determined by BC Hydro. The electricity delivered to BC Hydro's distribution system will also be deemed to be delivered to BC Hydro's transmission system (that is, no distribution loss adjustment will be applied to the electricity from an independent power producer or self-generator when determining capacity and energy delivered to BC Hydro's transmission system).
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rate under this Rate Schedule includes a rate increase of 1.00% before rounding.

ACCEPTED:__________________________

ORDER NO.__________________________

COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULE 1280 – SHORE POWER SERVICE (DISTRIBUTION)

Availability	For the supply of Shore Power to Port Customers who qualify for General Service for use by Eligible Vessels while docked at the Port Customer's Port Facility, on an interruptible basis. Shore Power Service is supplied at 60 Hz, three phase at Primary Voltage.
Applicable in	Rate Zone I.
Rate	**Administrative Charge:** \$150.00 per month plus **Energy Charge:** 10.442 ¢ per kWh
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. BC Hydro may refuse or Terminate Service under this Rate Schedule in circumstances where BC Hydro does not have sufficient energy or capacity. For greater certainty, BC Hydro will not be required to construct an Extension for the purpose of increasing the capacity of BC Hydro's distribution system to provide Shore Power Service under this Rate Schedule. 2. The terms and conditions under which Shore Power Service is supplied are contained in the Shore Power Service Agreement (Electric Tariff Supplement No. 86). The Port Customer will pay to BC Hydro the charges set out in this Rate Schedule in addition to any charges set out in the Shore Power Service Agreement. 3. A Port Customer that provides Port Electricity at a Port Facility under Rate Schedules 1600, 1601, 1610, 1611 or 1823 is not eligible to take Shore Power Service under this Rate Schedule to provide Port Electricity to that Port Facility, or any Port Facility served by the same BC Hydro delivery facilities.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

	4. On each occasion, if any, that BC Hydro is required to dispatch power line technicians or other workers to operate the switchgear for each connect and disconnect of Eligible Vessels docked at the Port Customer's Port Facility, BC Hydro will charge, and the Port Customer will pay, the reasonable time and labour costs for this service. The charge will be based on prevailing BC Hydro contracted labour rates and will be separately itemized on the Port Customer's monthly bill.
Definitions	For purposes of this Rate Schedule, capitalized terms have the meanings given to them in Electric Tariff Supplement No. 86.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

2. GENERAL SERVICE

RATE SCHEDULES 1300, 1301, 1310, 1311 – SMALL GENERAL SERVICE (UNDER 35 KW)

Availability	For Customers who qualify for General Service and whose Demand, metered or estimated by BC Hydro, as applicable, is less than 35 kW. Supply is 60 hertz, single or three phase at a Secondary or Primary Voltage.
Applicable in	Rate Zone I and Rate Zone IB.
Rate	**Basic Charge:** 36.22 ¢ per day plus **Energy Charge:** 12.45 ¢ per kWh **Minimum Charge:** The Basic Charge
Discounts	1. A discount of 1½% will be applied to the above charges if Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per month per kW of Demand will be applied if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.
Rate Schedules	1. Rate Schedule 1300: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1301: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation.

	3. Rate Schedule 1310: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1311: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Special Conditions	Special Conditions for Unmetered Service: 1. BC Hydro may permit unmetered Service under these Rate Schedules if it can estimate to its satisfaction the Energy used in kilowatt hours over a period of two months based on the connected load and the hours of use. 2. The Customer, if required by BC Hydro, will provide and maintain such controls, including timing devices, as BC Hydro considers necessary, and facilities satisfactory to BC Hydro for the maintenance of such controls. 3. The hours of use per period will be as specified by the Customer, or as estimated by BC Hydro, whichever is greater. 4. The Customer will supply, install and maintain all wiring, fixtures, control devices and equipment, including the controls and devices described in Special Condition No. 2, at the expense of the Customer. 5. All wiring, fixtures, control devices and equipment and the method of installing, operating and maintaining the same are subject to the approval of BC Hydro which approval may be withdrawn by BC Hydro, at any time, at BC Hydro's sole discretion. 6. The Customer will notify BC Hydro immediately of any proposed or actual change in load, load characteristics, or hours of use.

7. BC Hydro may at any time, in its sole discretion, install Metering Equipment, and thereafter bill the Customer on the appropriate Rate Schedule as a metered account.

8. For display signs and signboard lighting, where hours of use are controlled by timing devices, the following turn-on times will apply, unless BC Hydro otherwise agrees in writing:

Period	Turn-on Time
January 1 to January 15:	4:00 p.m.
January 16 to February 28:	4:30 p.m.
March 1 to April 30:	6:30 p.m.
May 1 to August 15:	8:30 p.m.
August 16 to September 30:	6:30 p.m.
October 1 to November 15:	4:30 p.m.
November 16 to December 31:	4:00 p.m.

9. In all cases, where hours of use of display signs or signboard lighting commence at dusk and are controlled either by timing devices or by photo-electric cells, the following hours of use for a period of two months will be deemed for billing purposes:

Dusk to 10 p.m.:	216 hours
Dusk to 11 p.m.:	270 hours
Dusk to 12 p.m.:	330 hours
Dusk to 1 a.m.:	380 hours
Dusk to Dawn:	666 hours

(All times are Pacific Time.)

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

	Migration Rules: 1. Migration rules from Small General Service: Customers taking Service under these Rate Schedules will be moved to Service: (a) Under Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) if Demand in half of the last six bi-monthly billing periods or half of the last 12 monthly billing periods (as applicable) was 35 kW or more, but less than 150 kW. (b) Under Rate Schedules 1600, 1601, 1610 or 1611 (Large General Service) if Demand in half of the last six bi-monthly billing periods or half of the last 12 monthly billing periods (as applicable) was 150 kW or more, or if total Energy consumption in any 12 consecutive month period exceeded 550,000 kWh. 2. Migration rules to Small General Service: Customers will be moved to Service under these Rate Schedules (Small General Service) from Rate Schedules 1600, 1601, 1610 or 1611 (Large General Service) or Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) if Billing Demand in each of the last 12 billing periods was less than 35 kW.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a rate increase of 1.00% before rounding.

ACCEPTED:__________________________

ORDER NO.__________________________

____
COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULES 1500, 1501, 1510, 1511 – MEDIUM GENERAL SERVICE (35 KW OR GREATER AND LESS THAN 150 KW)

Availability	For Customers who qualify for General Service and whose Billing Demand is equal to or greater than 35 kW but less than 150 kW, and whose Energy consumption in any 12-month period is equal to or less than 550,000 kWh. Supply is 60 hertz, single or three phase at Secondary or Primary Voltage. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone I.
Rate	**Basic Charge:** 26.56 ¢ per day plus **Demand Charge:** $5.38 per kW of Billing Demand plus **Energy Charge:** 9.62 ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per Billing Period per kW of Billing Demand will be applied to the above charges if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.

ACCEPTED:________________________

ORDER NO.________________________

COMMISSION SECRETARY

Monthly Minimum Charge	50% of the highest Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding 11 Billing Periods. For the purpose of this provision an on-peak period commences on November 1 in any year and terminates on March 31 of the following year.
Rate Schedules	1. Rate Schedule 1500: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1501: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1510: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1511: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Definitions	1. Billing Demand The Billing Demand will be the highest kW Demand in the Billing Period. 2. Billing Period A month between regular meter readings, provided that in cases where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

Special Conditions	1. Metering Metering Equipment with both Demand and Energy measurement capability will normally be installed. Until such Metering Equipment is installed, or if the installed Metering Equipment does not have Demand measurement capability, Billing Demand will be as estimated by BC Hydro 2. Migration Rules 2.1. Migration rules from Medium General Service: Customers taking Service under these Rate Schedules (Medium General Service) will be moved to Service: (a) Under Rate Schedules 1300, 1301, 1310 or 1311 (Small General Service) if Billing Demand in each of the last 12 consecutive Billing Periods was less than 35 kW. (b) Under Rate Schedules 1600, 1601, 1610 or 1611 (Large General Service) if Billing Demand in half of the last 12 Billing Periods was 150 kW or more, or if total Energy consumption in any 12 consecutive month period exceeded 550,000 kWh.

	2.2. Migration rules to Medium General Service: Customers will be moved to Service under these Rate Schedules (Medium General Service): (a) From Rate Schedules 1600, 1601, 1610 or 1611 (Large General Service) if Billing Demand in each of the last 12 Billing Periods was 35 kW or more, but less than 100 kW, and Energy consumption during the same period was less than 400,000 kWh. (b) From Rate Schedules 1300, 1301, 1310 or 1311 (Small General Service) if Billing Demand in half of the last six bi-monthly Billing Periods or half of the last 12 monthly Billing Periods (as applicable) was 35 kW or more, but less than 150 kW, and total Energy consumption in the same period was less than 550,000 kWh.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a rate increase of 1.00% before rounding.

2. GENERAL SERVICE

RATE SCHEDULES 1600, 1601, 1610, 1611 – LARGE GENERAL SERVICE (150 KW AND OVER)

Availability	For Customers who qualify for General Service and whose Billing Demand is equal to or greater than 150 kW, or whose Energy consumption in any 12 month period is greater than 550,000 kWh. Supply is 60 hertz, single or three phase at Secondary or Primary Voltage. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone I.
Rate	**Basic Charge:** 26.56 ¢ per day plus **Demand Charge:** $12.26 per kW of Billing Demand plus **Energy Charge:** 6.02 ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per Billing Period per kW of Billing Demand will be applied to the above charges if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.

ACCEPTED:____________________________

ORDER NO.____________________________

COMMISSION SECRETARY

Monthly Minimum Charge	50% of the highest Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding 11 Billing Periods. For the purpose of this provision an on-peak period commences on November 1 in any year and terminates on March 31 of the following year.
Rate Schedules	1. Rate Schedule 1600: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1601: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1610: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1611: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Definitions	1. Billing Demand The Billing Demand will be the highest kW Demand in the Billing Period. 2. Billing Period A month between regular meter readings, provided that where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.

Special Conditions	1. Metering Metering Equipment with both Demand and Energy measurement capability will normally be installed. Until such Metering Equipment is installed, or if the installed Metering Equipment does not have Demand measurement capability, Billing Demand will be as estimated by BC Hydro. 2. Migration Rules 2.1. Migration rules from Large General Service: Customers taking Service under these Rate Schedules (Large General Service) will be moved to Service: (a) Under Rate Schedules 1300, 1301, 1310 or 1311 (Small General Service) if Billing Demand in each of the last 12 consecutive Billing Periods was less than 35 kW. (b) Under Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) if Billing Demand in each of the last 12 consecutive Billing Periods was 35 kW or more but less than 100 kW, and Energy consumption in the same period was less than 400,000 kWh. 2.2. Migration rules to Large General Service: Customers will be moved to Service under these Rate Schedules (Large General Service) from Rate Schedules 1300, 1301, 1310 or 1311 (Small General Service) or Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) if Billing Demand in half of the last six bi-monthly Billing Periods or half of the last 12 monthly Billing Periods (as applicable) was 150 kW or more, or if total Energy consumption in any 12 consecutive month period exceeded 550,000 kWh.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.

ACCEPTED:____________________________

ORDER NO.____________________________ ____________________________
COMMISSION SECRETARY

Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a rate increase of 1.00% before rounding.

ACCEPTED:________________________

ORDER NO.________________________ ________________________________
COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULES 1640, 1641, 1642, 1643 – OVERNIGHT RATE (150 KW AND OVER)

Availability	For Customers who qualify for General Service where the Customer is a business, government agency or other organization. For use only for separately metered charging of Electric Fleet Vehicles or Vessels owned or leased by, and operated by, the Customer, at Maximum Demand equal to or greater than 150 kW. Supply is 60 hertz, single or three phase at Secondary or Primary Voltage. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone 1.
Rate	**Basic Charge:** 26.56 ¢ per day plus **Demand Charge:** $12.26 per kW of Billing Demand per Billing Period plus **Energy Charge:** 7.41 ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per Billing Period per kW of Billing Demand will be applied to the above charges if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.

Monthly Minimum Charge	50% of the highest Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding 11 Billing Periods. For the purpose of this provision an on-peak period commences on November 1 in any year and terminates on March 31 of the following year.
Rate Schedules	1. Rate Schedule 1640: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1641: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1642: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1643: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Definitions	1. Billing Demand The Billing Demand will be the highest kW Demand between the hours 06:00 and 22:00 daily in the Billing Period. Notwithstanding the foregoing, the Billing Demand will be the highest kW Demand in the Billing Period for the purposes of determining: (i) any discount under this Rate Schedule for Customer supplied Transformation; and (ii) BC Hydro’s contribution towards an Extension under section 8.3 (Extension Fee for Rate Zone I).

	2. Billing Period A month between regular meter readings, provided that where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period. 3. Electric Fleet Vehicle or Vessel A Vehicle or Vessel that: (a) Is powered entirely or partially by electricity; and (b) Is part of a group of similar Vehicles or Vessels that are used for similar purposes. 4. Vehicle A vehicle used for transportation, not run on rails, and includes, without limitation, buses, medium duty trucks and heavy duty trucks. 5. Vessel A watercraft used for transportation and includes, without limitation, passenger and vehicle ferries, tugs and barge transportation.
Special Conditions	1. Metering Metering Equipment with both Demand and Energy measurement capability will be installed. Only charging of Electric Fleet Vehicles or Vessels and related equipment will be served under these Rate Schedules. 2. Migration Customers taking service under these Rate Schedules will not be migrated to Rate Schedules 1300, 1301, 1310, or 1311 (Small General Service) or Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) due to changes in load size. BC Hydro will review this Special Condition in its evaluation report planned for the third year after which the rate commences.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

	3. Concurrent Service under other Rate Schedules BC Hydro will not provide service to equipment installed for service under these Rate Schedules under any other rate schedule except Rate Schedule 1901.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a rate increase of 1.00% before rounding.

2. GENERAL SERVICE

RATE SCHEDULES 1650, 1651, 1652, 1653 – DEMAND TRANSITION RATE (150 KW AND OVER)

Availability	For Customers who qualify for General Service where the Customer is a business, government agency or other organization. For use only for separately metered charging of Electric Fleet Vehicles or Vessels owned or leased by, and operated by, the Customer, at Maximum Demand equal to or greater than 150 kW. Supply is 60 hertz, single or three phase at Secondary or Primary Voltage. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone 1.
Termination Date	These Rate Schedules will terminate effective March 31, 2032. As of April 1, 2032 customers will be migrated to Rate Schedules 16xx or the otherwise applicable rate.
Rate	**Basic Charge:** 26.56 ¢ per day plus **Demand Charge:** $0 per kW of Billing Demand until March 31, 2026 plus **Energy Charge:** 9.12 ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per Billing Period per kW of Billing Demand will be applied to the above charges if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.

ACCEPTED:______________________

ORDER NO.______________________ ______________________
COMMISSION SECRETARY

Monthly Minimum Charge	50% of the highest Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding 11 Billing Periods. For the purpose of this provision an on-peak period commences on November 1 in any year and terminates on March 31 of the following year.
Rate Schedules	1. Rate Schedule 1650: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1651: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1652: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1653: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Definitions	1. Billing Demand The Billing Demand will be the highest kW Demand in the Billing Period. 2. Billing Period A month between regular meter readings, provided that where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.

	3. Electric Fleet Vehicle or Vessel A Vehicle or Vessel that: (a) Is powered entirely or partially by electricity; and (b) Is part of a group of similar vehicles or Vessels that are used for similar purposes. 4. Vehicle A vehicle used for transportation, not run on rails, and includes, without limitation, buses, medium duty trucks and heavy duty trucks. 5. Vessel A watercraft used for transportation and includes, without limitation, passenger and vehicle ferries, tugs and barge transportation.

Special Conditions	1. Demand and Energy Charge Pricing The Demand and Energy Charge Pricing over the period that these Rate Schedules are in effect is provided in the following table. No Demand Charge shall apply to Customers receiving service under these Rate Schedules for the first six years of the rate, from April 1, 2020 to March 31, 2026. As of April 1, 2026 the Demand Charge will be transitioned to the Rate Schedules 1600, 1601, 1610 and 1611 (Large General Service) Demand Charge over six years and completed by March 31, 2032, unless otherwise authorized by the Commission. The Energy Charge will be subject to general rate increases during the period of April 1, 2020 to March 31, 2026. As of April 1, 2026 the Energy Charge will be transitioned to the Rate Schedules 1600, 1601, 1610 and 1611 (Large General Service) Energy Charge over six years, to March 31, 2032, unless otherwise authorized by the Commission.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

		Effective Date	Fiscal Year	Demand Charge	Energy Charge
		April 1, 2020	F2021	$0	9.03 ¢ per kWh
		April 1, 2021	F2022	$0	9.13 ¢ per kWh
		April 1, 2022	F2023	$0	F2022 Energy Charge x RRA increase
		April 1, 2023	F2024	$0	F2023 Energy Charge x RRA increase
		April 1, 2024	F2025	$0	F2024 Energy Charge x RRA increase
		April 1, 2025	F2026	$0	F2025 Energy Charge x RRA increase
		April 1, 2026	F2027	F2026 Demand Charge + [F2027 LGS Demand Charge ÷ 6]	F2026 Energy Charge + [F2027 LGS Energy Charge] ÷ 6
		April 1, 2027	F2028	F2027 Demand Charge + [F2028 LGS Demand Charge-F2027 Demand Charge] ÷ 5	F2027 Energy Charge + [F2028 LGS Energy Charge-F2027 Energy Charge] ÷ 5
		April 1, 2028	F2029	F2028 Demand Charge + [F2029 LGS Demand Charge-F2028 Demand Charge] ÷ 4	F2028 Energy Charge + [F2029 LGS Energy Charge-F2028 Energy Charge] ÷ 4
		April 1, 2029	F2030	F2029 Demand Charge + [F2030 LGS Demand Charge-F2029 Demand Charge] ÷ 3	F2029 Energy Charge + [F2030 LGS Energy Charge-F2029 Energy Charge] ÷ 3
		April 1, 2030	F2031	F2030 Demand Charge + [F2031 LGS Demand Charge-F2030 Demand Charge] ÷ 2	F2030 Energy Charge + [F2031 LGS Energy Charge-F2030 Energy Charge] ÷ 2
		April 1, 2031	F2032	F2032 LGS Demand Charge	F2032 LGS Energy Charge

	2. Metering Metering Equipment with both Demand and Energy measurement capability will be installed. Only charging of Electric Fleet Vehicles or Vessels and related equipment will be served under this rate schedule. 3. Migration Customers taking service under these Rate Schedules will not be migrated to Rate Schedules 1300, 1301, 1310, or 1311 (Small General Service) or Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) due to changes in load size. BC Hydro will review this Special Condition in its evaluation report planned for the third year after which the rate commences. 4. Concurrent Service under other Rate Schedules BC Hydro will not provide service to equipment installed for service under these Rate Schedules under any other rate schedule except Rate Schedule 1901.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under these Rate Schedules include a rate increase of 1.00% before rounding.

3. IRRIGATION SERVICE

RATE SCHEDULE 1401 – IRRIGATION SERVICE

Availability	For motor loads of 746 watts or more used for irrigation and outdoor sprinkling where Electricity will be used principally during the Irrigation Season as defined below. Supply is 60 hertz, single or three phase at the Secondary or Primary Voltage available. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone I and Rate Zone IB.
Rate	1. During the Irrigation Season: **Energy Charge:** 6.08 ¢ per kWh **Minimum Charge:** $6.08 per kilowatt of connected load per month for a period of eight months commencing in March in any year whether Energy consumption is registered or not. 2. During the Non-Irrigation Season: **Energy Charge:** First 150 kWh @ 6.08 ¢ per kWh All additional kWh @ 48.21 ¢ per kWh **Minimum Charge:** Where Energy consumption is 500 kWh or less, Nil. Where Energy consumption is more than 500 kWh, $48.63 per kilowatt of connected load.
Discount for Ownership of Transformers	A discount of 25 ¢ per month per kW of connected load will be applied to the above charges if a Customer supplies the Transformation.

ACCEPTED:____________________

ORDER NO.____________________

COMMISSION SECRETARY

Definitions	1. Irrigation Season: In respect of each Service Connection the period commencing with a meter reading on or about March 1 in any year, having a mid-season meter reading on or about July 31, and ending with a meter reading on or about October 31 in that same year. BC Hydro may, in its discretion extend such period by postponing the termination date to any date not later than November 30, for the sole purpose of permitting a Customer to fill reservoirs necessary for the operation of the irrigation or sprinkling system. 2. Non-Irrigation Season: The period commencing at the end of one Irrigation Season and terminating at the beginning of the next Irrigation Season.
Special Conditions	1. No equipment provided with Electricity under this Rate Schedule will be served with Electricity under any other Rate Schedule while the Customer's Service Agreement under this Rate Schedule is in force. 2. Normally the Service Connection will be energized during the Non-Irrigation Season, but will be Disconnected if a Customer so requests. 3. The Minimum Charge during the Irrigation Season will commence in March for an account that has not been Terminated by the Customer, whether or not the Service Connection is energized and will be billed in two installments, at the end of July and at the end of October. 4. For the Irrigation Season, a bill will be rendered following the July and October meter readings. The first bill will be the greater of the Energy Charge and the Minimum Charge for the period March 1 to July 31. The second bill will be the greater of the Energy Charge for the season and the Minimum Charge for the season, less payment received for the first billing charges.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

	5. For the Non-Irrigation Season a bill will be rendered following the March meter reading provided that there is registered Energy consumption. 6. If a motor is rated in horsepower, the conversion factor from horsepower to kilowatts will be: 1 horsepower = 0.746 kilowatts
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a rate increase of 1.00% before rounding.

ACCEPTED:______________________

ORDER NO.______________________ ______________________
COMMISSION SECRETARY

4. STREET LIGHTING SERVICE

RATE SCHEDULE 1701 – OVERHEAD STREET LIGHTING

Availability	For lighting of public highways, streets and lanes in cases where BC Hydro owns, installs and maintains the fixtures, conductors, controls and poles.
Applicable in	Any area served by suitable overhead distribution lines.
Rate	Per fixture per month as set out below: 50 watt or less LED unit $15.23 51 to 80 watt LED unit $18.96 81 to 120 watt LED unit $23.74 greater than 120 watt LED unit $27.85 *100 watt H.P. sodium vapour unit $19.47 *150 watt H.P. sodium vapour unit $23.23 *200 watt H.P. sodium vapour unit $26.82 *175 watt mercury vapour unit $21.40 *250 watt mercury vapour unit $24.66 *400 watt mercury vapour unit $31.78 Wattages are unit wattages for LED and lamp watts for high pressure sodium vapour and mercury vapour. * Note Special Condition No. 2.
Special Conditions	1. Connection Charge No charge will be made for Service Connections.

2. Mercury Vapour and High Pressure Sodium Vapour

   Mercury vapour fixtures and high pressure sodium vapour fixtures are not available for new installations.

3. Extension Policy

   BC Hydro will construct a distribution Extension if required by the applicant in accordance with the Terms and Conditions of the Electric Tariff as applicable.

   When, at the Customer's request, a new fixture replaces an existing fixture, the Customer will pay to BC Hydro the original cost of the existing fixture, less any accumulated depreciation, and the cost of removing the existing fixture.

4. Relocation and Redirection of Fixtures

   The Customer will pay the full cost of relocating or redirecting fixtures when the change is made at the request of the Customer.

5. Design

   BC Hydro will design the installation of overhead street lighting fixtures.

6. Street Lights Failing to Operate

   BC Hydro will, without charge, replace street lights or components that fail to operate, unless breakage is the reason for such failure in which case the Customer will be charged the cost of the material required to make the fixture operate.

7. Term of Service Agreement

   The term of the initial Service Agreement under this Rate Schedule will be not more than five years; renewal periods will be for five years.

Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Supplemental Charge	Effective May 1, 2021, a transition rate supplemental charge equal to $2.06 per fixture per month applies to all street lights billed under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a rate increase of 1.00% before rounding. Effective May 1, 2021 this Rate Schedule includes an interim supplemental charge.

ACCEPTED:____________________________

ORDER NO.____________________________ ____________________________________

COMMISSION SECRETARY

4. STREET LIGHTING SERVICE

RATE SCHEDULE 1702 – PUBLIC AREA ORNAMENTAL STREET LIGHTING

Availability	For lighting of public highways, streets and lanes and municipal pathways and for public area seasonal lighting displays, in those cases where the Customer owns, installs and maintains the standards, fixtures, conductors and controls.
Applicable in	All Rate Zones.
Rate	**Energy Charge:** For each unmetered fixture: 3.75 ¢ per watt of Billing Wattage per month For each metered fixture: 11.25 ¢ per kWh
Definitions	Billable Wattage is the sum of all wattage, on all fixtures used by the Customer. For fixtures without dimming controls, the watts per fixture will include the wattage of the lamp plus, where applicable, the wattage of the ballast. For fixtures with dimming controls, the watts per fixture will be equal to: 1. The wattage of the lamp plus, where applicable, the wattage of the ballast, multiplied by 2. The ratio of effective fixture wattage after dimming to fixture wattage before dimming.

ACCEPTED:________________________

ORDER NO.________________________ ________________________

COMMISSION SECRETARY

Special Conditions	1. Service Connection Where necessary BC Hydro will provide an overhead or underground Service Connection in accordance with the Terms and Conditions of the Electric Tariff. No Service Connection will be made to add any ornamental street lighting system which does not provide for eight or more street lighting fixtures except that, if the potential is 120/240 volts, at BC Hydro's discretion, a Service Connection may be made for a system of less than eight. Receptacle loads will be permitted for Service under this Rate Schedule provided that such receptacles are used predominantly for seasonal lighting displays, meaning that no more than 10% of the usage may be for other purposes. 2. Extension Policy BC Hydro will construct a distribution Extension if required by the applicant in accordance with the Terms and Conditions of the Electric Tariff. 3. Power Factor All installations of mercury vapour, sodium vapour or fluorescent lamps will be equipped with the necessary auxiliaries to assure that a Power Factor of not less than 90% lagging will be maintained. 4. Term of Service Agreement The term of the initial Service Agreement under this Rate Schedule will be not more than five years; renewal periods will be for five years.

5. Fixtures with Automated Dimming Controls

The following special terms and conditions apply to lighting fixtures fitted with dimming controls:

(a) For purposes of this Special Condition No. 5, "dimming controls" means control units or fittings attached to, or forming part of, a street lighting fixture capable of being programmed or remotely operated so as to reduce the lumens output of the lamps during specified hours each day while the lamps are in operation. The reductions may vary according to the hours of the day, the days of the week, and the seasons of the year.

(b) A Customer wishing to have fixtures with dimming controls separately rated under this Rate Schedule must submit a dimming schedule satisfactory to BC Hydro listing each light fixture fitted with dimming controls, the wattage of the fixture (including the lamp and, where applicable, the ballast), the dimming control setting or settings and the hours each day that the dimming control setting or settings will be in operation.

(c) Whenever the Customer wishes to make changes in the lighting fixtures listed in the dimming schedule or in the dimming control settings or hours of operation, the Customer will submit an updated lighting fixture schedule to BC Hydro listing any changes. Changes will be permitted on a semi-annual basis (twice per year).

ACCEPTED:____________________________

ORDER NO.____________________________ ____________________________________

COMMISSION SECRETARY

	6. Unmetered Service (a) BC Hydro may permit unmetered Service under this Rate Schedule if it can estimate to its satisfaction the Energy used in kilowatt hours over a period of one month based on the connected load and hours of use. (b) The Customer will notify BC Hydro immediately of any proposed or actual change in load, or load characteristics, or hours of use. (c) BC Hydro, in its discretion, may at any time install Metering Equipment and thereafter bill the Customer on the Energy consumption registered.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a rate increase of 1.00% before rounding.

ACCEPTED:____________________________

ORDER NO.____________________________ ____________________________

COMMISSION SECRETARY

4. STREET LIGHTING SERVICE

RATE SCHEDULE 1703 – STREET LIGHTING SERVICE

Availability	For lighting of public highways, streets and lanes in those cases where the Customer owns, installs and maintains the fixtures, conductors and controls on poles of BC Hydro. Available only to Customers formerly taking Service on Rate Schedule 1755, 1756, 1757, 1758, 1759 or 1767, to the City of New Westminster in respect of a portion of D.L. 172, to the Municipality of Sparwood and to the City of Vancouver.
Applicable in	The Cities of Victoria and Prince Rupert, the Municipalities of Oak Bay, Esquimalt, Saanich and Central Saanich, the Village of Sidney, the unorganized areas of Port Renfrew and Shawnigan Lake, a portion of D.L. 172 in the City of New Westminster, Natal and the City of Vancouver.
Rate	**Energy Charge:** 3.75 ¢ per watt of Billing Wattage per month plus **Contact Charge:** $1.12 per contact per month The Contact Charge is a per fixture charge for the use of pole space.
Definitions	Billable Wattage is the sum of all wattage, on all fixtures used by the Customer. For fixtures without dimming controls, the watts per fixture will include the wattage of the lamp plus, where applicable, the wattage of the ballast. For fixtures with dimming controls, the watts per fixture will be equal to: 1. The wattage of the lamp plus, where applicable, the wattage of the ballast, multiplied by 2. The ratio of effective fixture wattage after dimming to fixture wattage before dimming.

Special Conditions	1. Extension Policy No Extension will be made to provide Service to street lights under this Rate Schedule. 2. Power Factor All installations of mercury vapour, sodium vapour or fluorescent lamps will be equipped with the necessary auxiliaries to assure that a Power Factor of not less than 90% lagging will be maintained. 3. Term of Service Agreement The term of the initial Service Agreement under this Rate Schedule will be not more than five years; renewal periods will be for five years. 4. Fixtures with Automated Dimming Controls The following special terms and conditions apply to lighting fixtures fitted with dimming controls: (a) For purposes of this Special Condition No. 4, “dimming controls” means control units or fittings attached to, or forming part of, a street lighting fixture capable of being programmed or remotely operated so as to reduce the lumens output of the lamps during specified hours each day while the lamps are in operation. The reductions may vary according to the hours of the day, the days of the week, and the seasons of the year. (b) A Customer wishing to have fixtures with dimming controls separately rated under this Rate Schedule must submit a dimming schedule satisfactory to BC Hydro listing each light fixture fitted with dimming controls, the wattage of the fixture (including the lamp and, where applicable, the ballast), the dimming control setting or settings and the hours each day that the dimming control setting or settings will be in operation.

ACCEPTED:____________________________

ORDER NO.____________________________

____
COMMISSION SECRETARY

	(c) Whenever the Customer wishes to make changes in the lighting fixtures listed in the dimming schedule or in the dimming control settings or hours of operation, the Customer will submit an updated lighting fixture schedule to BC Hydro listing any changes. Changes will be permitted on a semi-annual basis (twice per year).
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a rate increase of 1.00% before rounding.

ACCEPTED:____________________________

ORDER NO.____________________________ ____________________________________
COMMISSION SECRETARY

4. STREET LIGHTING SERVICE

RATE SCHEDULE 1704 – TRAFFIC CONTROL EQUIPMENT

Availability	For lighting of traffic signals, traffic signs and traffic warning devices, and other equipment for controlling or directing vehicular or pedestrian traffic on public highways in those cases where the Customer owns, installs, and maintains the standards, fixtures, controls and associated equipment.
Applicable in	All Rate Zones.
Rate	**Energy Charge:** 11.25 ¢ per kWh
Special Conditions	1. Service Connections Where necessary BC Hydro will provide an overhead or underground Service Connection in accordance with section 3 of the Terms and Conditions (Provision of Electricity). 2. Unmetered Service (a) BC Hydro may permit unmetered Service under this Rate Schedule if it can estimate to its satisfaction the Energy used in kilowatt hours over a period of one month based on the connected load and hours of use. (b) The Customer shall notify BC Hydro immediately of any proposed or actual change in load, or load characteristics, or hours of use. (c) BC Hydro, in its discretion, may at any time install a meter or meters and thereafter bill the Customer on the consumption registered.

ACCEPTED:________________________

ORDER NO.________________________ ______________________________
COMMISSION SECRETARY

	3. Term of Service Agreement The term of the initial Service Agreement under this Rate Schedule will be not more than five years; renewal periods will be for five years.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rate under this Rate Schedule includes a rate increase of 1.00% before rounding.

ACCEPTED:____________________________

ORDER NO.____________________________ __________________________________

COMMISSION SECRETARY

4. STREET LIGHTING SERVICE

RATE SCHEDULE 1755 – PRIVATE OUTDOOR LIGHTING (CLOSED)

Availability	For outdoor lighting Service to illuminate property other than public streets or lanes (private property), where Service is provided from dusk to dawn and the supply is single phase, 60 hertz at the Secondary Voltage available. This Rate Schedule is available only in Premises served under this Rate Schedule on January 1, 1975 and only with respect to lights served under this Rate Schedule on January 1, 1975 and continuously thereafter, except BC Hydro may replace a mercury vapour unit with a high pressure sodium unit having approximately the same equivalent light output.
Applicable in	All Rate Zones.
Rate	**Charge per fixture per month as follows:** 1. Where a light is mounted on a pole that was installed by the Customer or by BC Hydro at the Customer's expense: 175 watt mercury vapour unit or replacement 100 watt H.P. sodium vapour unit — $18.25 400 watt mercury vapour unit or replacement 150 watt H.P. sodium vapour unit — $31.46

ACCEPTED:____________________________

ORDER NO.____________________________

COMMISSION SECRETARY

	2. Where a light is mounted on a pole that is on public property, or an easement, and is part of BC Hydro's distribution system: 175 watt mercury vapour unit or replacement 100 watt H.P. sodium vapour unit — $19.38 400 watt mercury vapour unit or replacement 150 watt H.P. sodium vapour unit — $32.60 3. Where a light is mounted on a pole that was installed on the Customer's property by BC Hydro, at its expense, solely for the purpose of supporting the light: 175 watt mercury vapour unit or replacement 100 watt H.P. sodium vapour unit — $23.87 400 watt mercury vapour unit or replacement 150 watt H.P. sodium vapour unit — $37.57 Except that if two or more lights are mounted at one time on the same pole the rates for the additional light or lights will be as set out under part 1 above.
Special Conditions	1. BC Hydro will provide and install: (a) An outdoor light consisting of luminaire, mast arm, ballast, lamp and photo-electric control, and (b) Not more than one span of overhead secondary conductors per light. 2. The Customer will be required to contribute the estimated cost of any plant required to make Secondary Voltage available at a point not more than one span from the light; such contribution is not subject to refund.

ACCEPTED:____________________

ORDER NO.____________________

COMMISSION SECRETARY

	3. BC Hydro reserves the sole right to determine whether or not a light will be installed on a pole that is part of BC Hydro's distribution system. 4. The prior approval of BC Hydro is required if a Customer intends to install its own poles, and such poles will be maintained to BC Hydro's satisfaction at the Customer's expense. 5. BC Hydro will maintain all equipment owned by BC Hydro and will replace lamps which have failed. Any breakage will be repaired by BC Hydro at the Customer's expense.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a rate increase of 1.00% before rounding.

5. TRANSMISSION SERVICE

RATE SCHEDULE 1823 – TRANSMISSION SERVICE – STEPPED RATE

Availability	For all purposes. Supply is at 60 kV or higher. Customers supplied with Electricity under Rate Schedule 1825 (Time-of-Use) may only revert to Service under this Rate Schedule as permitted under Rate Schedule 1825.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Demand Charge:** \$8.642 per kVA of Billing Demand per Billing Period plus **Energy Charge: A** For new Customers and Customers that do not have a CBL by order of the British Columbia Utilities Commission: 5.065 ¢ per kWh for all kWh per Billing Period This rate will apply until the Customer has been supplied with Electricity under this Rate Schedule for 12 Billing Periods or another period approved by the British Columbia Utilities Commission, after which the Customer will be supplied with Electricity at the rate specified in Part B below.

ACCEPTED:__________

ORDER NO.__________

COMMISSION SECRETARY

	Energy Charge: B For Customers with a CBL: 4.507 ¢ per kWh applied to all kWh up to and including 90% of the Customer's CBL in each Billing Year 10.095 ¢ per kWh applied to all kWh above 90% of the Customer's CBL in each Billing Year Note: Customers previously supplied with Electricity under Rate Schedule 1825 will be subject to the rates in Part B above from the time the Customer commences taking Service under this Rate Schedule. **Monthly Minimum Charge:** $8.642 per kVA of Billing Demand
Definitions	1. Billing Year The Billing Year is the 12 month billing period starting with the first day of the Billing Period which commences nearest to April 1 in each year, and ending on the last day of such 12-month Billing Period.

2. Billing Demand

The Billing Demand will be:

(a) The highest kVA Demand during the High Load Hours (**HLH**) in the Billing Period; or

(b) 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or

(c) 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant,

whichever is the highest value, provided that for new Customers the Billing Demand for the initial two Billing Periods will be the average of the daily highest kVA Demands for the Customer's Plant.

	3. Customer Baseline Load (**CBL**) The Customer Baseline Load (**CBL**) is the Customer's historic annual energy consumption in kWh as approved by the British Columbia Utilities Commission. The Customer's CBL will initially be determined by BC Hydro, and be subject to revision from time to time, in accordance with the criteria and procedures set forth in BC Hydro's "Customer Baseline Load (**CBL**) Determination Guidelines" (Electric Tariff Supplement No. 74). All CBLs will be subject to final approval of the British Columbia Utilities Commission. 4. High Load Hours (**HLH**) High Load Hours (**HLH**) is the period of hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays (New Year's Day, Family Day, Good Friday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day). 5. Low Load Hours (**LLH**) Low Load Hours (**LLH**) are all hours other than HLH.
Special Conditions	1. A Customer having two or more operating plants may elect to have a single aggregated CBL determined for all or any combination of its operating plants in accordance with BC Hydro's "Customer Baseline Load (**CBL**) Determination Guidelines" (Electric Tariff Supplement No. 74). Thereafter, BC Hydro will issue a single bill for all operating plants included in the aggregation, and the Energy Charge payable will be determined on the basis of the aggregated CBL. However, the Demand Charge will continue to be determined separately for each operating plant.

	2. If any initial, revised, or aggregate CBL for a Customer has not been determined by BC Hydro and approved by British Columbia Utilities Commission by the time at which the CBL would become effective, BC Hydro may determine the CBL on an interim basis and apply that CBL for the purposes of any billing periods and bills rendered to the Customer until such time as the CBL has been finally determined and approved by the British Columbia Utilities Commission, following which BC Hydro will make any necessary billing adjustments. 3. If a Customer taking Service at the rates in Part B of the Energy Charge rate section above Terminates Service under this Rate Schedule prior to the end of a Billing Year, the Customer's CBL or aggregate CBL will be prorated for the portion of the Billing Year during which the Customer was taking Service, and the prorated CBL or aggregate CBL will be used for the purposes of applying the rates in Part B to all energy consumption during the Billing Year up to the time of Termination. BC Hydro will make any necessary billing adjustments and bill the Customer for the difference (if any) owing.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Note	The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement Nos. 5 and 6, or Electric Tariff Supplement Nos. 87 and 88, as applicable.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a rate increase of 1.00% before rounding.

5. TRANSMISSION SERVICE

RATE SCHEDULE 1825 – TRANSMISSION SERVICE – TIME-OF-USE (TOU) RATE

Availability	For Customers who provide notice by February 15 of each year and who at the time of application are eligible to take Service under Rate Schedule 1823 (Stepped Rate) at the Energy Charge rates set out in Part B of the rate section of that Rate Schedule, and who have entered into a TOU (Transmission Service) Agreement by March 15 of that year. Customers will start Service under Rate Schedule 1825 in the first Billing Period after April 1.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Demand Charge:** $8.642 per kVA of Billing Demand per Billing Period plus **Energy Charge:** 1. Winter HLH Period: 4.507 ¢ per kWh applied to all kWh up to and including 90% of the Customer's Winter HLH Period CBL. 11.265 ¢ per kWh applied to all kWh above 90% of the Customer's Winter HLH Period CBL. 2. Winter LLH Period: 4.507 ¢ per kWh applied to all kWh up to and including 90% of the Customer's Winter LLH Period CBL. 10.210 ¢ per kWh applied to all kWh above 90% of the Customer's Winter LLH Period CBL.

	3. Spring Period: 4.507 ¢ per kWh applied to all kWh up to and including 90% of the Customer's Spring Period CBL. 9.093 ¢ per kWh applied to all kWh above 90% of the Customer's Spring Period CBL. 4. Remaining Period: 4.507 ¢ per kWh applied to all kWh up to and including 90% of the Customer's Remaining Period CBL applicable. 9.971 ¢ per kWh applied to all kWh above 90% of the Customer's Energy CBL applicable in the Billing Period.
Definitions	1. Billing Demand The Demand for billing purposes will be: (a) The highest kVA Demand during the High Load Hours (**HLH**) in the Billing Period; or (b) 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or (c) 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant, whichever is the highest value.

2. Customer Baseline Load (CBL)

   The Customer Baseline Load (**CBL**) is the Customer's historic consumption (in kWh) as approved by the British Columbia Utilities Commission. For the purposes of this Rate Schedule, the Customer’s CBL will consist of four separate CBLs – one each for the Winter HLH Period, the Winter LLH Period, the Spring Period and the Remaining Period. The Customer’s CBL will initially be determined by BC Hydro, and be subject to revision from time to time, in accordance with the criteria and procedures set forth in BC Hydro's "Customer Baseline Load (**CBL**) Determination Guidelines" (Electric Tariff Supplement No. 74). All CBLs will be subject to final approval of the British Columbia Utilities Commission.

3. High Load Hours (**HLH**)

   High Load Hours (**HLH**) is the period of hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays (New Year’s Day, Family Day, Good Friday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day).

4. Low Load Hours (**LLH**)

   The Low Load Hours (**LLH**) are all hours other than HLH.

5. Remaining Period

   The Remaining Period is all Billing Periods other than the Winter Period or the Spring Period.

6. Spring Period

   The Spring Period comprises the two Billing Periods starting with the first day of the Billing Period that commences nearest to May 1 each year and ending on the last day of the second Billing Period thereafter.

	7. Winter Period The Winter Period comprises four Billing Periods starting with the first day of the Billing Period that commences nearest to November 1 each year and ending on the last day of the fourth Billing Period thereafter.
Special Conditions	1. Service under this Rate Schedule will be provided only while a TOU (Transmission Service) Agreement with the Customer is in effect. 2. A Customer having two or more operating plants may elect to have a single aggregated CBL determined for all or any combination of its operating plants in accordance with BC Hydro's "Customer Baseline Load (CBL) Determination Guidelines" (Electric Tariff Supplement No. 74). Separate Energy CBL values will be determined for each plant and then aggregated. BC Hydro will issue a single bill for all operating plants included in an aggregation, and the Energy Charge payable will be determined on the basis of the aggregated Energy CBL value. The Demand Charge will continue to be determined separately for each operating plant. 3. If any initial, revised, or aggregate CBL for a Customer has not been determined by BC Hydro and approved by British Columbia Utilities Commission by the time at which the CBL would become effective, BC Hydro may determine the CBL on an interim basis and apply that CBL for the purposes of any billing periods and bills rendered to the Customer until such time as the CBL has been finally determined and approved by the British Columbia Utilities Commission, following which BC Hydro will make any necessary billing adjustments.

	4. In accordance with the TOU (Transmission Service) Agreement, the Customer will have a period of 30 days following approval of the Customer's initial CBL by the British Columbia Utilities Commission within which the Customer may, by written notice to BC Hydro, withdraw from taking Service under this Rate Schedule, and revert to taking Service under Rate Schedule 1823 (Stepped Rate). This right of withdrawal is available only when the Customer first subscribes to take Service under this Rate Schedule, and is applicable only in respect of the initial CBL determination. If the Customer exercises this right of withdrawal Rate Schedule 1823 will apply from the commencement of the then current Billing Year, and BC Hydro will make any necessary billing adjustments accordingly. 5. Customers taking Service under Rate Schedule 1852 (Modified Demand) may not also take Service under this Rate Schedule.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Note	The terms and conditions under which Transmission Service is supplied are contained in the Electricity Supply Agreement (Electric Tariff Supplement No. 5, or Electric Tariff Supplement No. 87, as applicable) as amended by the Electric Tariff Supplement No. 72 (TOU (Transmission Service) Agreement), and Electric Tariff Supplement No. 6, or Electric Tariff Supplement No. 88, as applicable.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a rate increase of 1.00% before rounding.

ACCEPTED:____________________

ORDER NO.____________________

____
COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1827 – TRANSMISSION SERVICE – RATE FOR EXEMPT CUSTOMERS

Availability	For all purposes. Supply is at 60 kV or higher. Only for City of New Westminster and University of British Columbia and other Customers exempted from Rate Schedule 1823 (Stepped Rate) by the British Columbia Utilities Commission.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Demand Charge:** \$8.642 per kVA of Billing Demand per Billing Period plus **Energy Charge:** 5.065 ¢ per kWh for all kWh in a Billing Period **Monthly Minimum Charge:** \$8.642 per kVA of Billing Demand
Definitions	1. Billing Demand The Billing Demand will be: (a) The highest kVA Demand during the High Load Hours (**HLH**) in the Billing Period; or (b) 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or (c) 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant, whichever is the highest value.

	2. High Load Hours (**HLH**) High Load Hours (**HLH**) is the period of hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays (New Year's Day, Family Day, Good Friday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day). 3. Low Load Hours (**LLH**) Low Load Hours (**LLH**) are all hours other than HLH.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Note	The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement Nos. 5 and 6, or Electric Tariff Supplements Nos. 87 and 88, as applicable.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2021 the rates under this Rate Schedule include a rate increase of 1.00% before rounding.

5. TRANSMISSION SERVICE

RATE SCHEDULE 1852 – TRANSMISSION SERVICE – MODIFIED DEMAND

Availability	To a Customer supplied with Electricity at 60 kV or higher who is taking Service under Rate Schedule 1823 (Stepped Rate) at the time of application, and is a party to a Modified Demand Agreement under Electric Tariff Supplement No. 54 which is in force, and which is in a location, as determined by BC Hydro, that will allow BC Hydro to curtail load to alleviate a potential local or regional transmission constraint, or take advantage of a market opportunity. The annual subscription period for new subscribers is from September 1 to October 31.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Excess Demand Charge:** $8.642 per kVA of metered kVA Demand in excess of the Maximum Demand Level during Low Load Hours
Definitions	1. Billing Demand The Billing Demand will be: (a) The highest kVA Demand during the High Load Hours (**HLH**) in the Billing Period; or (b) 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or (c) 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant, whichever is the highest value.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

2. High Load Hours (**HLH**)

   High Load Hours (**HLH**) means the period(s) in a 24-hour day and during those days of a calendar week in which Electricity usage is typically highest in a particular region, as determined by BC Hydro in its discretion based on load characteristics and transmission constraints in that region from time to time, and designated in a Modified Demand Agreement.

3. Low Load Hours (**LLH**)

   Low Load Hours (**LLH**) are all hours other than HLH.

4. LLH CBL Energy

   LLH CBL Energy means the highest monthly energy consumption during the LLH over the last 12 Billing Periods, or an estimate of consumption if insufficient data is available.

5. Maximum Demand Level

   Maximum Demand Level has the meaning set out in the Modified Demand Agreement. For a Customer with more than one designated period of High Load Hours, separate Maximum Demand Levels will be stated for each corresponding period of Low Load Hours. For a Customer with a single designated period of High Load Hours, a single Maximum Demand Level will be stated for all Low Load Hours.

   The highest Maximum Demand Level will not exceed 95% of Contract Demand stated in the Customer's Electricity Supply Agreement, and is subject to local transmission availability.

Special Conditions	1. The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement Nos. 5 and 6. The provisions of Rate Schedule 1823 (Stepped Rate) and Electric Tariff Supplement Nos. 5 and 6 continue to apply to Customers receiving Service under this Rate Schedule. In the case of a conflict between this Rate Schedule or the Modified Demand Agreement and Rate Schedule 1823 or Electric Tariff Supplement Nos. 5 or 6, the provisions of this Rate Schedule and the Modified Demand Agreement will govern. 2. If for any two Billing Periods the total energy consumed under Rate Schedule 1852, during the LLH, is greater than the LLH CBL Energy by 10% or more, the highest kVA Demand in each such Billing Period during the High Load Hours will be adjusted by the ratio of the average monthly LLH Energy during such two Billing Periods over the LLH CBL Energy. The adjusted highest kVA Demand will apply for a period of 12 months after the second Billing Period included in the adjustment calculation. The LLH CBL Energy will be recalculated using the consumption history of the most recent 12 Billing Periods. 3. The Minimum Reduction under the Modified Demand Agreement will be the greater of 50% of the difference between the Maximum Demand Level and the LLH CBL Demand, and 10 MW. 4. The Maximum Number of Demand Reduction Transactions under the Modified Demand Agreement will be the greater of Maximum Duration multiplied by the Maximum Number of Demand Reduction Transactions, and 48 hours.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

ACCEPTED:________________________

ORDER NO.________________________

COMMISSION SECRETARY

Rate Increase	Effective April 1, 2021 the rate under this Rate Schedule includes a rate increase of 1.00% before rounding.

ACCEPTED:____________________________

ORDER NO.____________________________

____
COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1853 – TRANSMISSION SERVICE – IPP STATION SERVICE

Availability	For Customers who are Independent Power Producers (**IPPs**) served at transmission voltage, on an interruptible basis.
Applicable in	Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Energy Charge:** The sum, over the Billing Period, of the hourly energy consumed multiplied by the entry in the Intercontinental Exchange (**ICE**) Mid-Columbia (Mid-C) Peak, and Mid-C Off-Peak weighted average index price as published by the ICE in the ICE Day Ahead Power Price Report that corresponds to the time when consumption occurred, during that hour
Monthly Minimum Charge	$48.70
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. 2. BC Hydro may, without notice to the Customer, refuse to supply or terminate the supply of Electricity under this Rate Schedule if at any time BC Hydro does not have sufficient energy or capacity. 3. Prior to taking Electricity under this Rate Schedule, the Customer may be required to obtain approval from BC Hydro. BC Hydro will advise the Customer of the need to obtain approval prior to the taking of Electricity under this Rate Schedule. 4. Electricity taken under this Rate Schedule is to be used solely for maintenance and black-start requirements and will not displace electricity that would normally be generated by the Customer.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

Taxes	The rates and Monthly Minimum Charge set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2021 the Monthly Minimum Charge under this Rate Schedule includes a rate increase of 1.00% before rounding.

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1880 – TRANSMISSION SERVICE – STANDBY AND MAINTENANCE SUPPLY

Availability	For Customers supplied with Electricity under Rate Schedule 1823 (Stepped Rate), 1825 (TOU Rate), 1827 (Rate for Exempt Customers), 1828 (Biomass Energy Program) or 1852 (Modified Demand), on an interruptible basis.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Administrative Charge:** \$150.00 per Period of Use plus **Energy Charge:** During the Period of Use, 10.095 ¢ per kWh of metered Rate Schedule 1880 energy consumption, determined as set out below
Definitions	1. HLH Reference Demand HLH Reference Demand is the highest kVA Demand in the HLH for the current Billing Period prior to the Period of Use, but excluding any prior Period of Use. If the Period of Use extends over an entire Billing Period, the highest kVA Demand in the HLH from the prior Billing Period will be used in determining the HLH Reference Demand, excluding any Period of Use in the prior Billing Period. For the purpose of determining HLH Reference Demand, the HLH periods are as defined in Rate Schedule 1823, 1825, 1827, 1828 or 1852, whichever is applicable.

ACCEPTED:________________________

ORDER NO.________________________

COMMISSION SECRETARY

	2. Period of Use A period of consecutive hours during which Electricity is taken under this Rate Schedule. The Period of Use is as defined by the Customer when requesting Service from BC Hydro under this Rate Schedule 1880 and may extend into subsequent Billing Periods.
Rate Schedule 1880 Energy Determination	During HLH periods, the kWh consumption on an hourly basis which exceeds the HLH high kWh per hour within the Period of Use or portion thereof where HLH high kWh per hour is the product of HLH Reference Demand multiplied by the Power Factor for the half hour when the HLH Reference Demand occurred. For the purpose of the Rate Schedule 1880 Energy Determination, the HLH periods are as defined in Rate Schedule 1823, 1825, 1827, 1828 or 1852, whichever is applicable.
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. 2. BC Hydro may, without notice to the Customer, refuse to supply or terminate the supply of Electricity under this Rate Schedule if at any time during the Period of Use BC Hydro does not have sufficient energy or capacity.

3. This Rate Schedule is only for the following purposes:

   To provide Electricity the Customer would otherwise generate during periods when all or part of the Customer's electrical generating plant is curtailed.

   Electricity used for this purpose may be taken on an instantaneous basis when the impact of the instantaneous pickup of loads normally provided by the Customer’s electrical generation units does not occur after BC Hydro has advised the Customer that a period of system constraint or potential system constraint exists.

   During periods of potential system constraints, BC Hydro will require Customers to arm load shedding relays to ensure that the loss of electricity production from a Customer’s electrical generation unit will not result in a demand greater than the Customer’s Maximum kVA Demand on BC Hydro’s system. BC Hydro may require the Customer to provide it with control of these load shedding relays. During periods of potential system constraints, upon a Customer’s request, BC Hydro will endeavour to provide Electricity normally provided by the Customer’s electrical generation unit.

   The Customer is required to advise BC Hydro within 30 minutes of taking Electricity under this Rate Schedule for this purpose. If the Customer fails to advise BC Hydro within 30 minutes, measured Demand and Energy consumption will be billed under Rate Schedule 1823, 1825, 1827, 1828 or 1852, whichever is applicable.

4. Electricity taken under this Rate Schedule will not displace Electricity otherwise to be taken by the Customer under Rate Schedule 1823, 1825, 1827, 1828 or 1852.

   Electricity taken under this Rate Schedule will not displace electricity that would normally be generated by the Customer for the purpose of re-sale.

	5. In addition to the charges specifically set out in this Rate Schedule, the Customer will pay for any additional facilities required to deliver Electricity under this Rate Schedule provided that BC Hydro obtains the prior consent of the Customer for construction of the additional facilities. 6. A Customer may be required to allow BC Hydro to install metering and communication equipment to measure the electricity output of the Customer's self-generation unit. 7. BC Hydro will bill for Electricity taken under Rate Schedule 1880 at the same time it bills for Electricity taken under Rate Schedule 1823, 1825, 1827, 1828 or 1852, whichever is applicable.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Note	The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement Nos. 5 and 6, or Electric Tariff Supplement Nos. 87 and 88, as applicable.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2021 the Energy Charge under this Rate Schedule includes a rate increase of 1.00% before rounding.

ACCEPTED:________________________

ORDER NO.________________________

COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1891 – TRANSMISSION SERVICE – SHORE POWER SERVICE

Availability	For the supply of Shore Power to Port Customers for use by Eligible Vessels while docked at the Port Customer's Port Facility, on an interruptible basis. Supply is at 60 kV or higher.
Applicable in	Rate Zone I.
Rate	**Administrative Charge:** $150.00 per month plus **Energy Charge:** 10.095 ¢ per kWh for all kWh in a billing period
Definitions	For purposes of this Rate Schedule, capitalized terms have the meanings given to them in the Shore Power Service Agreement (Electric Tariff Supplement No. 86).
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. BC Hydro may refuse Service under this Rate Schedule in circumstances where BC Hydro does not have sufficient energy or capacity. For greater certainty, BC Hydro will not be required to construct a System Reinforcement under Electric Tariff Supplement No. 6 to provide Shore Power Service under this Rate Schedule. 2. The terms and conditions under which Shore Power Service is supplied are contained in the Shore Power Service Agreement (Electric Tariff Supplement No. 86). The Port Customer will pay to BC Hydro the charges set out in this Rate Schedule in addition to any charges set out in the Shore Power Service Agreement.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

	3. A Port Customer that provides Port Electricity at a Port Facility under Rate Schedules 1600, 1601, 1610, 1611 (Large General Service) or 1823 (Stepped Rate) is not eligible to take Shore Power Service under this Rate Schedule to provide Port Electricity to that Port Facility, or a Port Facility served by the same BC Hydro delivery facilities. 4. On each occasion, if any, that BC Hydro is required to dispatch power line technicians or other workers to operate the switchgear for each connect and disconnect of Eligible Vessels docked at the Port Customer's Port Facility, BC Hydro will charge, and the Port Customer will pay, the reasonable time and labour costs for this service. The charge will be based on prevailing BC Hydro contracted labour rates and will be separately itemized on the Port Customer's monthly bill.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

5. TRANSMISSION SERVICE

RATE SCHEDULE 3808 – TRANSMISSION SERVICE – FORTISBC INC.

Availability	This Rate Schedule is available to FortisBC Inc. (FortisBC) in accordance with the terms and conditions of the Agreement between BC Hydro and FortisBC entered into and deemed effective July 1, 2014 (Power Purchase Agreement). Contract Demand must not exceed 200 MW in any hour.
Applicable in	For Electricity delivered to FortisBC at each Point of Delivery as defined in the Power Purchase Agreement.
Rate	**Demand Charge:** \$8.642 per kW of Billing Demand per Billing Month plus **Energy Charge:** Tranche 1 Energy Price: 5.065 ¢ per kWh Tranche 2 Energy Price: 9.509 ¢ per kWh

ACCEPTED:______________________________

ORDER NO.______________________________

____
COMMISSION SECRETARY

Definitions	1. Billing Demand The Billing Demand in any Billing Month will be the greatest of: (a) The maximum amount of Electricity (in kW) scheduled under the Power Purchase Agreement, for any hour of the Billing Month; (b) 75% of the maximum amount of Electricity (in kW) scheduled under the Power Purchase Agreement in any hour in the 11 months of the Term immediately prior to the Billing Month (or less than 11 months, if the Effective Date is less than 11 months prior to the month); and (c) 50% of the Contract Demand (in kW) for the Billing Month. If FortisBC has reduced the Contract Demand in accordance with the Power Purchase Agreement, the amount of Electricity specified in item (b) above may not exceed an amount equal to 100% of the Contract Demand. 2. Maximum Tranche 1 Amount The Maximum Tranche 1 Amount for each Contract Year is 1,041 GWh. 3. Scheduled Energy Less Than or Equal to Annual Energy Nomination In any Contract Year, for the amount of the Scheduled Energy taken or deemed to be taken that is less than or equal to the Annual Energy Nomination, FortisBC will pay: (a) The Tranche 1 Energy Price for each kWh of such Scheduled Energy taken or deemed taken that is less than or equal to the Maximum Tranche 1 Amount; and (b) The Tranche 2 Energy Price for each kWh of such Scheduled Energy taken that exceeds the Maximum Tranche 1 Amount.

ACCEPTED:______________________

ORDER NO.______________________

____
COMMISSION SECRETARY

	4. Scheduled Energy Exceeding the Annual Energy Nomination In any Contract Year, for the amount of the Scheduled Energy taken or deemed to be taken that exceeds the Annual Energy Nomination, FortisBC will pay: (a) 150% of the Tranche 1 Energy Price, for each kWh of such Scheduled Energy taken or deemed taken that that exceeds the Annual Energy Nomination, but is less than or equal to the Maximum Tranche 1 Amount; and (b) 115% of the Tranche 2 Energy Price, for each kWh of such Scheduled Energy taken that exceeds the Annual Energy Nomination and also exceeds the Maximum Tranche 1 Amount. 5. Annual Minimum Take In any Contract Year, FortisBC will schedule and take an amount of Electricity equal to at least 75% of the Annual Energy Nomination, and will be responsible for any Annual Shortfall.
Note	The terms and conditions under which Service is supplied to FortisBC are contained in the Power Purchase Agreement.
Taxes	The rates and charges set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase	The Tranche 1 Energy Price and Demand Charge set out above are subject to the same rate adjustments as Rate Schedule 1827 (Rate for Exempt Customers). Tranche 2 Energy Price is subject to changes as provided for in the Power Purchase Agreement. Effective April 1, 2021 the Tranche 1 Energy Price and the Demand Charge under this Rate Schedule include a rate increase of 1.00% before rounding.

ATTACHMENT H

Annual Transmission Revenue Requirement for Network Integration Transmission Service

1. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be $978,303,960.

2. The amount in (1) shall be effective until amended by the Transmission Provider or modified by the Commission.

Effective April 1, 2021, this rate schedule is approved.

ACCEPTED:____________________________

ORDER NO.____________________________

____
COMMISSION SECRETARY

Schedule 00

Network Integration Transmission Service

Availability	For wholesale transmission of electricity.
Rate	Monthly Transmission Revenue Requirement: Customers will be charged their load ratio share of one twelfth (1/12th) of the Network Transmission Revenue Requirement per month. The Transmission Revenue Requirement is shown in Attachment H. One-twelfth of the Transmission Revenue Requirement is $81,525,330.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Note	The terms and conditions under which Network Integration Transmission Service is supplied are contained in BC Hydro's OATT. Capitalized terms appearing in this Schedule, unless otherwise noted, shall have the meaning ascribed to them therein.

Effective April 1, 2021, this rate schedule is approved.

ACCEPTED:____________________________

ORDER NO.____________________________

COMMISSION SECRETARY

Schedule 01

Point-To-Point Transmission Service

Availability	For transmission of electricity on a firm and non-firm basis from one or more Point(s) of Receipt (POR) to one or more Point(s) of Delivery (POD).
Rate for Long-Term Firm Service	The Reserved Capacity Charge for the Long-Term Firm Service Rate will be up to a maximum price as set out below except where the POD is a point of interconnection between the Transmission System and the transmission system of FortisBC Inc., in which case the rate shall be zero ($0.00). The Maximum Reserved Capacity Charge is $78,262/MW of reserved capacity per year to be invoiced monthly. Reserved Capacity Billing Demand The Reserved Capacity Billing Demand is determined for each POR(s), POD(s) pair. The Reserved Capacity for each pair of POR(s) and POD(s) will be the maximum non-coincident sum of the designated POR(s) and POD(s) included in the pair.

Schedule 01 – Point-To-Point Transmission Service (continued)

Rate for Short-Term Firm and Non-Firm Service	The posted prices for Short-Term Firm and Non-Firm Service will be less than or equal to a maximum price ($/MWh) as set out below, except where the POD is a point of interconnection between the Transmission System and the transmission system of FortisBC Inc., in which case the rate shall be zero ($0.00). Maximum Price for: 1. Monthly delivery: $6,521.81/MW of Reserved Capacity per month. 2. Weekly delivery: $1,505.03/MW of Reserved Capacity per week. 3. Daily delivery: $214.42/MW of Reserved Capacity per day. 4. Hourly delivery: $8.93/MW of Reserved Capacity per hour. Discount Rate: For discounted paths posted on the Transmission Provider's OASIS, the Transmission Customer shall pay each month for Reserved Capacity Billing Demand the greater of the rates set forth below and the rate offered by the Transmission Customer and accepted by the Transmission Provider up to the maximum rate for Short-Term Firm and Non-Firm Service: 1. Hourly delivery: $3/MW of Reserved Capacity per hour in the Heavy Load Hour period (06:00-22:00, Monday - Saturday, excluding NERC holidays) and $1/MW of Reserved Capacity per hour for the Light Load Hour period (remaining hours and days). 2. Daily delivery: sum of the hourly delivery charge in the 24 hour period in the day.
Reserved Capacity for Short-Term Firm and Non-Firm Services	The Reserved Capacity shall be the maximum of the sum of non-coincident POD(s) Capacity Reservations or sum of non-coincident POR(s) Capacity Reservations.

ACCEPTED:____________________

ORDER NO.____________________

COMMISSION SECRETARY

Schedule 01 – Point-To-Point Transmission Service (continued)

Penalty Charge	In addition to the applicable rate for service and associated charges for Ancillary Services, a penalty charge will be applied to all unauthorized usage at a rate of 125 percent of the maximum hourly delivery charge.
Special Conditions	Discounts: The following conditions apply to discounts for transmission service: 1. any offer of a discount made by BC Hydro must be announced to all Eligible Customers solely by posting on the OASIS, 2 any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, 3. once a discount is negotiated, details must be immediately posted on the OASIS, and 4. for any discount agreed upon for service on a path, from POR(s) POD(s), BC Hydro must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same POD(s) on the Transmission System.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Resales	The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff
Note	The terms and conditions under which Transmission Service is supplied are contained in BC hydro's Open Access Transmission Tariff. Capitalized terms appearing in this Rate Schedule, unless otherwise noted, shall have the meaning ascribed to them therein.

Effective April 1, 2021, this rate schedule is approved.

ACCEPTED:____________________________

ORDER NO.____________________________ ____________________________________
COMMISSION SECRETARY

Schedule 03

Scheduling, System Control, and Dispatch Service

Preamble	This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by BC Hydro. The Transmission Customer must purchase this service from BC Hydro. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below.
Availability	In support of Network Integration Transmission Service, Long and Short-Term Firm Point-to-Point Transmission Service, and Non-Firm Point-to-Point Transmission Service.
Rate	$0.152 per MW of Reserved Capacity per hour.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Note	A description of the methodology for discounting Scheduling, System Control and Dispatch Services provided under this Schedule is contained in Section 3 of the BC Hydro OATT.

Effective April 1, 2021, this rate schedule is approved.

ACCEPTED:____________________________

ORDER NO.____________________________

____
COMMISSION SECRETARY

BC Hydro Fiscal 2022
Revenue Requirements Application

Compliance with
BCUC Decision and Order G-187-21

Appendix C

Draft Order

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2022 Revenue Requirements Application

BEFORE:
D.M. Morton, Panel Chair
T.A. Loski, Commissioner
R. I. Mason, Commissioner

on XXX, 2021

ORDER

WHEREAS:

A. On December 22, 2020, British Columbia Hydro and Power Authority (BC Hydro) filed its Fiscal 2022 Revenue Requirements Application (Application) with the British Columbia Utilities Commission (BCUC) pursuant to sections 58 to 61 and 89 of the *Utilities Commission Act* (UCA), requesting, among other things, an approval of an increase in rates by 1.16 per cent, effective April, 1, 2021;

B. By Order No. G-187-21 dated June 17, 2021, the British Columbia Utilities Commission (Commission) approved the request rate increase of 1.16 per cent, subject to adjustments resulting from various determinations and directives, including Directive 26, which directs BC Hydro "to increase its F[iscal] 2022 forecast revenue by the estimated value of the low carbon fuel credits that it plans to transfer to other parties, if any, during F[iscal] 2022" and "to record in all future R[evenue] R[equirements] A[pplication]s, the forecast revenue based on an estimate of the value of the low carbon fuel credits that it plans to transfer to other parties";

C. On July 16, 2021, BC Hydro filed its compliance filing to Order No. G-187-21 (Compliance Filing), in which BC Hydro applied for the establishment of a new regulatory account – the Low Carbon Fuel Credits Variance Regulatory Account – to capture, on an ongoing basis, the difference between planned and actual revenues from low carbon fuel credits in a given year; and

D. The Commission reviewed BC Hydro's request for the establishment of the Low Carbon Fuel Credits Variance Regulatory Account and grants the establishment of the requested regulatory account.

…/2

NOW THEREFORE, pursuant to sections 58 to 61 of the UCA, the Commission orders as follows:

1. The Low Carbon Fuel Credits Variance Regulatory Account is approved to capture, on an ongoing basis, the difference between forecast and actual miscellaneous revenue from low carbon fuel credits. BC Hydro is to apply interest on the balance of this regulatory account based on BC Hydro's current weighted average cost of debt and to amortize the balance of the account into rates through the Deferral Account Rate Rider.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment Options

BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

Appendix AA

Report on the Non-Integrated Areas Demand-Side Management Program and Evaluation of DSM Effectiveness

Table of Contents

List of Attachments

1 Introduction

BC Hydro provides this appendix in response to Directive 47 from the BCUC decision on the Fiscal 2020 – Fiscal 2021 Revenue Requirements Application (**Directive 47**) and in response to Directive 19 from the BCUC decision on the Previous Application (**Directive 19**). Directive 47 requires BC Hydro to report on progress with regards to the Non-Integrated Areas (**NIA**) DSM program, including an assessment of whether that program has been effective in reducing barriers for NIA customers in accessing DSM offerings. Directive 19 requires BC Hydro to include BC Hydro's most recent evaluation of its DSM effectiveness.

2 Report on Progress in the NIA (Directive 47)

In compliance with Directive 47, BC Hydro provides its Report on Demand Side Management Activities for Fiscal 2021 (**DSM Activities Report**)[1]. This report includes BC Hydro's progress on the NIA DSM program for the fiscal year ending March 2021 and has been included as Attachment 1 to this appendix.

Section 3 of the DSM Activities Report provides a report of DSM activity in the NIA. In addition, BC Hydro's fiscal 2021 DSM expenditures, electricity savings and cost effectiveness results for the NIA program are shown as a line item within Table 1 and Table 3 through Table 6, along with all other programs.

[1] In compliance with Directive 69 (page 197) of the BCUC Decision G-96-04 on BC Hydro's Fiscal 2005 to Fiscal 2006 Revenue Requirements Application (as amended by subsequent BCUC orders), BC Hydro submits annual DSM Activities Report to the BCUC.

3 BC Hydro's most recent Evaluation of its DSM Effectiveness (Directive 19)

In compliance with Directive 19, BC Hydro provides the DSM Activities Report which provides information on DSM expenditures, electricity savings, and plan performance for the fiscal year ending in March 2021.

In addition, BC Hydro provides the two most recent annual Demand Side Management Milestone Evaluation Summary Reports[2] covering fiscal 2019 and fiscal 2020. They have been included as Attachment 2 and Attachment 3 to this appendix.

[2] In compliance with Directive 66 (page 197) of the Commission Decision G-96-04 on BC Hydro's Fiscal 2005 to Fiscal 2006 Revenue Requirements Application, BC Hydro annually submits the executive summaries of its milestone evaluation reports and full final evaluation reports of all its DSM programs to the BCUC.

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix AA

Attachment 1

Demand Side Management Activities for Fiscal 2021

BC Hydro
Power smart

Chris Sandve
Chief Regulatory Officer
Phone: 604-623-3918
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

July 15, 2021

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2005 – Fiscal 2006 Revenue Requirements Application
BCUC Decision G-96-04 dated October 29, 2004: Directive 69
(AMENDED pursuant to 2006 Integrate Electricity Plan and
2006 Long-Term Acquisition Plan
BCUC Decision G-29-07 dated May 11, 2007: Directive 16)
2008 Long-Term Acquisition Plan
BCUC Decision G-91-09 dated July 27, 2009: Directives 36, 38 and 42
Fiscal 2017 – Fiscal 2019 Revenue Requirements Application
BCUC Decision G-47-18 dated March 1, 2018: Directive 23
Fiscal 2020 – Fiscal 2021 Revenue Requirements Application
BCUC Decision G-246-20 dated October 2, 2020: Directives 47, 49, 50 and 51

BC Hydro writes to provide its Report on Demand Side Management Activities for the 12 months ending March 31, 2021.

For further information, please contact Joe Maloney at 604-623-4348 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Chris Sandve
Chief Regulatory Officer

st/rh

Enclosure

BC Hydro
Power smart

Report on Demand-Side Management Activities for Fiscal 2021

July 15, 2021

BC Hydro
Power smart

Table of Contents

List of Tables

BC Hydro
Power smart

1 Introduction

This BC Hydro annual report to the British Columbia Utilities Commission (**BCUC** or **Commission**) on Demand-Side Management (**DSM**) activities provides information on DSM expenditures, electricity savings, plan performance and mitigation measures for the 2021 fiscal year, which is the twelve months ending March 31, 2021. This report also provides information on Low Carbon Electrification expenditures within the DSM Regulatory Account.

This annual report is filed in compliance with, or to reflect, the following BCUC Directives:

- Directive 69 from the BCUC Decision G-96-04 on BC Hydro's Fiscal 2005 to Fiscal 2006 Revenue Requirements Application (**F05-F06 RRA**);
- Directive 16 from the BCUC Decision G-29-07 on BC Hydro's 2006 Integrated Electricity Plan and Long-Term Acquisition Plan (**2006 IEP/LTAP**);
- Directives 36, 38, and 42 from the BCUC Decision G-91-09 on BC Hydro's 2008 Long-Term Acquisition Plan (**2008 LTAP**);
- Directive 23 from the BCUC Decision G-47-18 on BC Hydro's Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (**F17-F19 RRA**); and
- Directive 47, 49, 50 and 51 from the BCUC Decision G-246-20 on BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application **(F20-F21 RRA).**

Directive 69 of the F05-F06 RRA Decision directed BC Hydro "to provide information to the BCUC for on-going review of Power Smart performance through:

- Executive Summaries of milestone evaluation reports and full final evaluation reports for each program;
- Semi-annual- reports on DSM activities which, amongst others, will include:

BC Hydro
Power smart

- Detailed breakdown of OMA expenses related to support activities carried out within the Power Smart group and in other departments that support the Power Smart organization;
- Detailed description of the functions of portfolio level costs and how these costs are allocated to programs;
- Summaries of the overall performance of Power Smart with reference to program objectives; and
- Variances of fiscal year budgeted and actual deferred capital expenditures and explanation of variances."

Directive 16 of the 2006 IEP/LTAP Decision directed BC Hydro "to continue to file reports on DSM performance as described in Directive 69 of the F05/F06 RRA Decision included in Order No. G-9604 and to file its Semi Annual Demand-Side Management Reports in the same format as the June 2005 Report with the following enhancements:

(i) Provide annual and cumulative totals since program inception;

(ii) Express these values on a per unit basis; and

(iii) Provide the benefit to cost ratios for the three DSM tests."

Directive 36 of the 2008 LTAP Decision directed BC Hydro to switch from semi-annual to annual DSM performance reports. Directive 38 from the same Decision directed BC Hydro to include in these reports:

> "…metrics for each initiative, achievements in relation to milestones, and description of past or planned mitigation measures where warranted. These mitigation measures should include shifting program resources and alternative supply options for each program. Ongoing DSM performance reporting should demonstrate how BC Hydro is continuously pursuing DSM and that specific programs are cost-effective."

Directive 42 of the 2008 LTAP Decision directed BC Hydro to continue to report on a Ratepayer Impact Measure (**RIM**) test values.

Directive 23 of the F17-F19 RRA Decision directs BC Hydro to "include a line item in BC Hydro's Annual Report on DSM Activities to reflect the Non-Integrated Area (**NIA**) activities that are tracked separately."

Directive 47 of the F20-F21 RRA Decision directed BC Hydro, among other things, to report on the progress of the NIA program in future annual DSM reports, and in the fiscal 2023 Revenue Requirements Application, "including an assessment of whether that program has been effective in reducing barriers for Non-Integrated Area customers in accessing DSM offerings and thereby meeting the objective of Directive 23 from the 2017 to 2019 Revenue Requirements Application."

Directive 49 of the F20-F21 RRA Decision directed BC Hydro "to report on the Low Carbon Electrification expenditures within the DSM Regulatory Account annually in its annual DSM report to the BCUC, clearly allocated to the applicable classes defined in section 4(3) (a), (b), (c) or (d) of the GGRR, including a consolidated table with a break down between the Initial LCE and BC Hydro LCE projects and programs."

Directive 50 of the F20-F21 RRA Decision rescinded Directive 61 from Order G-96-04 on BC Hydro's F05-F06 RRA.

Directive 51 of the F20-F21 RRA Decision determined that BC Hydro may make inter-year and inter-program area transfers, as follows:

- BC Hydro may transfer unspent accepted DSM expenditures in a program area to the same program area in the following year of the Test Period, on the condition that BC Hydro provides information regarding unspent amounts as part of its annual DSM reports so that all amounts transferred within a program area are transparently accounted for from one test year to the next; and

- The Panel accepted the DSM expenditure schedule including transfers of up to 25 per cent of DSM expenditures from any one existing program area to any other existing program area.

BC Hydro files its evaluation reports pursuant to Directive 69 of the F05-F06 RRA Decision separately.

This annual report addresses the balance of Directives 69 and 16, as well as Directives 36, 38, and 42 of the 2008 LTAP Decision, Directive 23 of the F17-F19 RRA Decision and Directives 47, 49, 50 and 51 of the F20-F21 RRA.

2 Expenditures and Electricity Savings for Fiscal 2021 as a Result of DSM activities

BC Hydro's DSM expenditures[1] in fiscal 2021 totalled $77 million, while new incremental DSM electricity savings totalled 780 GWh/year. Expenditures were $12 million or 14 per cent below the Fiscal 2021 DSM Plan presented in BC Hydro's F20-F21 RRA. Overall, new incremental electricity savings as shown in Table 1 were 27 GWh/year or 4 per cent above the DSM Plan.

BC Hydro confirms that no unspent accepted DSM expenditures from fiscal 2020 were transferred to fiscal 2021. BC Hydro also confirms that over fiscal 2021, no transfers between program areas were made beyond the allowed levels.

Table 1 presents planned and actual DSM expenditures and new incremental electricity savings in fiscal 2021.

[1] Comprising all DSM-related deferred operating expenditures. DSM operating expenditures are presented in Table 8 of this report.

BC Hydro
Power smart

Table 1 Expenditures and New Incremental Electricity Savings for Fiscal 2021*

	Expenditures[1]				New Incremental Electricity Savings			
	Plan[2] $ 000	Actual $ 000	Variance $ 000	%	Plan[2] GWh/yr	Actual[3] GWh/yr	Variance GWh/yr	%
Rate Structures								
Residential Inclining Block Rate	-	-	-	-	-	-	-	-
General Service Rate	-	-	-	-	-	-	-	-
Transmission Service Rate	454	389	(65)	(14%)	118	119	2	1%
Total Rate Structures	454	389	(65)	(14%)	118	119	2	1%
DSM Programs								
Residential Sector								
Low Income	6,924	4,271	(2,654)	(38%)	9	5	(4)	(44%)
Non Integrated Areas	1,424	1,489	65	5%	0.6	0.4	(0.2)	(39%)
Retail	2,107	2,379	272	13%	5	9	4	74%
Home Renovation Rebate	4,360	5,952	1,592	37%	8	9	1	8%
Residential Energy Management Activities	4,888	4,245	(644)	(13%)	13	21	8	60%
Residential Sector Total	19,703	18,336	(1,367)	(7%)	36	44	8	23%
Commercial Sector								
LEM-C	9,102	9,121	19	0%	47	46	(1)	(2%)
New Construction	2,355	1,744	(610)	(26%)	5	5	(0)	(6%)
Commercial Energy Management Activities	6,091	5,288	(803)	(13%)	n/a	n/a	n/a	n/a
Commercial Sector Total	17,547	16,153	(1,395)	(8%)	52	51	(1)	(2%)
Industrial Sector								
LEM-I	18,525	14,913	(3,613)	(20%)	136	160	24	18%
Thermo-Mechanical Pulp	-	(2,672)	(2,672)	-	-	n/a	-	-
Industrial Energy Management Activities	8,362	6,905	(1,457)	(17%)	n/a	n/a	n/a	n/a
Industrial Sector Total	26,887	19,146	(7,741)	(29%)	136	160	24	18%
Total Programs	**64,138**	**53,635**	**(10,503)**	**(16%)**	**224**	**255**	**31**	**14%**
Supporting Initiatives								
Public Awareness	7,500	6,986	(514)	(7%)	-	-	-	-
Indirect and Portfolio Enabling	7,350	7,114	(236)	(3%)	-	-	-	-
Supporting Initiatives Total	**14,851**	**14,101**	**(750)**	**(5%)**	-	-	-	-
Total Programs, Rates & Supporting Initiatives	**79,443**	**68,125**	**(11,318)**	**(14%)**	**342**	**375**	**33**	**10%**
Codes and Standards	5,343	5,216	(127)	(2%)	411	405	(6)	(1%)
Capacity Focused DSM	4,266	3,664	(602)	(14%)	-	-	-	-
PORTFOLIO TOTAL	**89,052**	**77,005**	**(12,047)**	**(14%)**	**753**	**780**	**27**	**4%**

* Numbers may not add due to rounding.

Notes:

1 Including all DSM-related deferred operating expenditures.

2 Plan figures are from BC Hydro's F20-F21 RRA, Appendix X.

3 Reported savings from codes and standards and residential inclining block and transmission service rate structures are based on planned estimates as well as evaluated results.

Table 2 provides explanations of the variances between planned and actual expenditures and savings shown in Table 1 above:

Table 2 Variance Explanations between Planned and Actual Expenditures and Savings for Fiscal 2021

Rate Structures	
Transmission Service Rate	Expenditures were below plan due to planned rate design activities to explore potential changes to RS 1823 being delayed. Electricity savings were approximately on plan.
DSM Programs	
Residential Sector	
Low Income	Expenditures and savings were below plan due to the COVID-19 pandemic that forced the Energy Conservation Assistance Program (**ECAP**) portion of the program to suspend operations for four months. Participation was slow to recover once in-home visits resumed.
Non-Integrated Areas	Expenditures were approximately on plan. Electricity savings were below plan primarily due to the impact of the COVID-19 pandemic, which prevented on-site visits in some participating communities due to local health and safety protocols. In response, the program re-allocated dollars from incentives to provide more enabling support to Indigenous Nations, which brought program expenditures in approximately on plan.
Retail	Expenditures and savings were above plan due to higher participation in most product categories than planned during Q3 campaign, driven in large part by COVID-19 pandemic influenced demand in retail do-it-yourself home improvements.
Home Renovation Rebate	Expenditures and savings were above plan due to strong participation driven by the increased rebate promotion which was implemented in Q3 to support contractors and customers impacted by the COVID-19 pandemic.
Residential Energy Management Activities	Expenditures were below plan due to planned activities being deferred. Savings were above plan due to higher than planned participation in energy reduction challenges and higher than planned participation in the Energy Visualization Portlet where customers can see their detailed consumption history to determine when they are using electricity and opportunities to conserve.
Commercial Sector	
Leaders in Energy Management – Commercial (**LEM-C**)	Expenditures and electricity savings were approximately on plan.
New Construction	Expenditures were below plan due to a customer project being deferred to fiscal 2022 and resulting adjustments to project incentives. Electricity savings were approximately on plan.

BC Hydro
Power smart

Commercial Energy Management Activities	Expenditures were below plan due to energy manager positions becoming vacant at customers' sites, and the time required for customers to fill the vacancies.
Industrial Sector	
Leaders in Energy Management – Industrial (LEM-I)	Expenditures were below plan due to fewer incentive projects with customers than planned. Electricity savings were above plan due to higher savings from strategic energy management activity and customer-funded projects.
Thermo-Mechanical Pulp	No expenditures or electricity savings were planned. However, historical electricity savings were reduced based on actual performance of a project. The total incentive provided for the project was reduced to reflect the adjusted electricity savings. This resulted in a negative variance in expenditures.
Industrial Energy Management Activities	Expenditures were below plan due to energy manager positions becoming vacant, and the time required for customers to fill the vacancies.
Total Programs	Expenditures were below plan primarily due to fewer Industrial customers advancing incentive projects than planned, a reduction in incentives paid out to a customer in the Thermo-Mechanical Pulping program and Low-Income program operation suspensions due to the COVID-19 pandemic. Electricity savings were above plan primarily due to Industrial strategic energy management and customer-funded projects achieving higher savings than planned.
Supporting Initiatives	
Public Awareness	Expenditures were below plan due to Public Awareness activities being impacted by the COVID-19 pandemic restrictions which limited the opportunities for in-person community outreach and in-person school education programs and related expenses.
Indirect and Portfolio Enabling	Expenditures were approximately on plan.
Codes and Standards	Expenditures and electricity savings were approximately on plan.
Capacity Focused DSM	Expenditures were below plan due to delays in activities resulting from the impact of the COVID-19 pandemic.
Portfolio Total	Expenditures were below plan primarily due to fewer Industrial customers advancing incentive projects than planned, a reduction in the incentive provided to a customer in the Thermo-Mechanical Pulp program and Low-Income program operation suspensions due to the COVID-19 pandemic. Electricity savings were above plan primarily due to Industrial strategic energy management and customer-funded projects achieving higher savings than planned.

3 Non-Integrated Areas Activity

BC Hydro's fiscal 2021 DSM expenditures, electricity savings and cost effectiveness results for the NIA program are shown as a line item within Table 1 and Table 3 through Table 6, along with all other programs.

The barriers that BC Hydro has identified and is trying to address with the NIA program include awareness, acceptability, affordability, availability, and accessibility. The main components of the NIA program include:

- Indigenous Communities Conservation Program, which contains two streams:
  - Stream 1 provides free energy saving products, salary support and installation training for Indigenous Nations to hire local installers to conduct home energy upgrades such as energy efficient lighting, high performance faucets and showerheads, and basic draft proofing and to assess homes for additional energy-saving opportunities.
  - Stream 2 provides training to Indigenous Nations and their contractors to complete advanced home energy upgrades and provides rebates to support the cost of those upgrades (e.g., insulation, windows, doors, ventilation, heat pumps, etc.).

For communities that choose not to participate in the Indigenous Communities Conservation Program and for all other customers within the NIA, the following offers are available:

- Energy Savings Kits: free energy saving products are offered to NIA residential customers that they can install in their own homes;
- Home Renovation Rebates: NIA residential customers are offered bonus rebates on eligible home energy upgrades; and
- Business Energy Savings Incentives: NIA commercial customers, including Indigenous Nations, are eligible for bonus incentives through this program.

In addition to the above activities, BC Hydro has also implemented the following initiatives to help address barriers:

- Creation of a new role at BC Hydro that works directly with Indigenous Nations to support their participation in our programs; and
- Provision of funding for Energy Champion positions for the Indigenous communities, plus associated peer networks and training opportunities for Indigenous Nations.

NIA program activities in fiscal 2021 focused on the continued ramp up of the program as well as identifying ways to try to mitigate the impacts of the COVID-19 pandemic on NIA program delivery. Despite the COVID-19 pandemic, BC Hydro saw continued interest and a 30 per cent increase in program participation over fiscal 2020. In particular, BC Hydro continued provide support to Indigenous Nations to hire local installers and contractors so that home energy upgrades could continue in many communities, with protocols in place to adhere to provincial and local health orders.

For residential customers in the NIA, BC Hydro continued to offer bonus rebates on weatherization upgrades and introduced an increased rebate promotion on heat pumps. In addition, a direct mail campaign in the fall of 2020 encouraged NIA residential customers to order free Energy Savings Kits ahead of the winter heating season. With participation and energy savings below plan, BC Hydro provided more enabling support (e.g., funding energy focused staff positions, community energy planning, etc.) to Indigenous Nations. This support will help to build community capacity to pursue conservation and energy management activities and community goals.

BC Hydro is in the process of developing a performance measurement framework with Indigenous communities for the NIA program, which it expects to use to report on how the program is addressing community goals and barriers.

4 Expenditures to Date

BC Hydro's DSM expenditures for fiscal 2021 totalled $77 million. Table 3 presents DSM expenditures from April 1, 2020 to March 31, 2021.

BC Hydro
Power smart

Table 3 Expenditures for Fiscal 2020 to Fiscal 2021*

	F2020 ($ 000)	F2021 ($ 000)	Total ($ 000)
Rate Structures			
Residential Inclining Block Rate	-	-	-
General Service Rate	-	-	-
Transmission Service Rate	294	389	684
Total Rate Structures	**294**	**389**	**684**
DSM Programs			
Residential Sector			
Low Income	5,165	4,271	9,436
Non Integrated Areas	920	1,489	2,409
Retail	2,392	2,379	4,771
Home Renovation Rebate	4,791	5,952	10,743
Residential Energy Management Activities	4,664	4,245	8,909
Residential Sector Total	17,932	18,336	36,268
Commercial Sector			
LEM-C	9,078	9,121	18,199
New Construction	3,296	1,744	5,041
Commercial Energy Management Activities	6,077	5,288	11,365
Commercial Sector Total	18,452	16,153	34,605
Industrial Sector			
LEM-I	11,321	14,913	26,234
Thermo-Mechanical Pulp	-	(2,672)	(2,672)
Industrial Energy Management Activities	6,666	6,905	13,571
Industrial Sector Total	17,987	19,146	37,133
Total Programs	**54,371**	**53,635**	**108,006**
Supporting Initiatives			
Public Awareness	7,328	6,986	14,315
Indirect and Portfolio Enabling	6,851	7,114	13,965
Supporting Initiatives Total	**14,179**	**14,101**	**28,280**
Total Programs, Rates & Supporting Initiatives	**68,844**	**68,125**	**136,969**
Codes and Standards	5,246	5,216	10,462
Capacity Focused DSM	4,371	3,664	8,035
PORTFOLIO TOTAL	**78,462**	**77,005**	**155,467**

* Numbers may not add due to rounding.

BC Hydro Power smart

BC Hydro's DSM electricity savings since the beginning of fiscal 2020 totalled 1,340 GWh/year at March 31, 2021, which equates to 103 per cent of the planned savings of 1,300 GWh/year in the F20-F21 RRA. Table 4 presents actual cumulative savings as a percentage of plan as of the end of fiscal 2021.

Table 4 Cumulative Electricity Savings: Fiscal 2020 to Fiscal 2021

Actual as a Percentage of Plan[1]	
Rate Structures	
Residential Inclining Block Rate	n/a
General Service Rate	n/a
Transmission Service Rate	103%
Total Rate Structures	**103%**
DSM Programs	
Residential Sector	
Low Income	79%
Non Integrated Areas	47%
Retail	153%
Home Renovation Rebate	110%
Residential Energy Management Activities	145%
Residential Sector Total	120%
Commercial Sector	
LEM-C	94%
New Construction	101%
Commercial Energy Management Activities	n/a
Commercial Sector Total	95%
Industrial Sector	
LEM-I	108%
Thermo-Mechanical Pulp	n/a
Industrial Energy Management Activities	n/a
Industrial Sector Total	108%
Total Programs	**106%**
Codes and Standards	101%
Capacity Focused DSM	n/a
PORTFOLIO TOTAL	**103%**

Notes:

1 Reported savings for codes and standards and rates structures are based on planned estimates as well as evaluated results.

The cumulative portfolio DSM electricity savings from April 1, 2019 through March 31, 2021 have been achieved at an average net levelized utility cost of $23 per MWh. Table 5 presents net levelized utility cost that is calculated by subtracting capacity benefits from gross utility costs and then dividing the resulting net utility costs by electricity savings. A negative net levelized utility cost means that the subtracted capacity benefits exceed gross utility costs.

Table 5 Utility Cost of Electricity Savings: Fiscal 2020 to Fiscal 2021

	Net Levelized Utility Cost ($/MWh)
Rate Structures	
Residential Inclining Block Rate	n/a
General Service Rate	n/a
Transmission Service Rate	-5
Total Rate Structures	**-5**
DSM Programs	
Residential Sector	
Low Income	31
Non Integrated Areas	363
Retail	-2
Home Renovation Rebate	0
Residential Sector Total	**11**
Commercial Sector	
LEM-C	7
New Construction	14
Commercial Sector Total	8
Industrial Sector	
LEM-I	9
Thermo-Mechanical Pulp	n/a
Industrial Sector Total	7
Total Programs	**8**
Energy Management Activities	n/a
Supporting Initiatives[1]	n/a
Codes & Standards	n/a
Portfolio Total[2]	**23**

Notes:

1 Supporting initiatives costs have not been allocated to programs per Directive 50 of the F20-F21 RRA Decision, which rescinds Directive 61 from Order G-96-04 on BC Hydro's F05-F06 RRA. Directive 61 had directed BC Hydro to add a prorated amount of costs from supporting initiatives to the cost of each DSM program to assess cost-effectiveness.

2. Energy management activities, supporting initiatives costs and codes and standards costs are included at the portfolio level. Capacity focused DSM is not included in cost effectiveness calculations because this initiative is still in the trial and pilot stage and therefore the associated benefits have not yet been quantified.

Table 6 presents benefit cost-ratios of actual DSM electricity savings achieved from April 1, 2019 through March 31, 2021.

BC Hydro
Power smart

Table 6 Benefit Cost Ratios of Electricity Savings: Fiscal 2020 to Fiscal 2021

	Benefit Cost Ratios[1]			
	LRMC ($105 per MWh)			Market Price ($30 per MWh)
	Modified Total Resource Cost Test[2]	Total Resource Cost Test excluding NEBs	Ratepayer Impact Measure Test[3]	Utility Cost Test
Rate Structures				
Residential Inclining Block Rate	n/a	n/a	n/a	n/a
General Service Rate	n/a	n/a	n/a	n/a
Transmission Service Rate	3.3	3.3	1.0	29.0
Total Rate Structures	3.3	3.3	1.0	29.0
DSM Programs				
Residential Sector				
Low Income[4]	4.0	4.2	0.9	1.0
Non Integrated Areas[4&5]	1.1	1.1	0.7	0.9
Retail	3.6	3.7	1.1	2.4
Home Renovation Rebate	1.9	1.4	0.9	1.9
Residential Sector Total	2.4	2.1	0.9	1.6
Commercial Sector				
LEM-C[4]	4.2	2.8	1.2	2.2
New Construction	1.8	1.3	1.1	1.6
Commercial Sector Total	3.5	2.3	1.2	2.1
Industrial Sector				
LEM-I	6.1	4.4	1.1	2.1
Thermo-Mechanical Pulp	n/a	n/a	n/a	n/a
Industrial Sector Total	6.1	4.4	1.1	2.3
Total Programs	**3.7**	**2.8**	**1.1**	**2.0**
Energy Management Activities	n/a	n/a	n/a	n/a
Supporting Initiatives[6]	n/a	n/a	n/a	n/a
Codes & Standards	n/a	n/a	n/a	n/a
Portfolio Total[7]	**2.6**	**2.0**	**0.9**	**1.2**

Notes:

1 To align with BC Hydro's F20-F21 RRA, this report uses a long-run marginal cost (LRMC) of $105 per MWh. As described in BC Hydro's F20-F21 RRA, Chapter 10, this value is based on an outdated assessment of greenfield wind projects, including BC Hydro's cost to integrate and deliver energy to the load centre (Lower Mainland). BC Hydro plans to update the LRMC in the next IRP. Internal decisions on demand-side measures are based on the Utility Cost Test at market price and not on the LRMC.

2 In accordance with the DSM Regulation, the avoided cost of natural gas is valued at BC Hydro's LRMC of acquiring electricity generated from clean or renewable resources in B.C. converted to $/gigajoule (**GJ**) in all time periods. Non-energy benefits in the DSM Regulation are valued at 15 per cent of the energy and capacity benefits of electricity and natural gas, or as quantified by the Utility.

3. While subsection 4(6) of the DSM Regulation precludes the use of the Ratepayer Impact Measure Test in determining cost effectiveness of a demand-side measure, this benefit cost ratio is included in the table to comply with Directive 42 from the BCUC decision on BC Hydro's 2008 LTAP.

4 The Total Resource Cost Test benefit cost-ratios for the Low Income, Non-Integrated Areas and Social Housing Retrofit component of the LEM-C Program include a 40 per cent adder to program benefits, in accordance with the DSM Regulation.

5 Avoided costs in all NIA cost tests are based on NIA generation costs $300 per MWh (F2015$).

6 Supporting initiatives costs have not been allocated to programs per Directive 50 of the F20-F21 RRA Decision.

7 Energy management activities, supporting initiatives costs and codes and standards costs are included in cost effectiveness calculations at the portfolio level. Capacity focused DSM is not included in cost effectiveness calculations because this initiative is still in the trial and pilot stage and therefore the associated benefits have not yet been quantified.

Based on the experience gathered over the past few years through initiative tracking, Table 7 sets out the mitigation measures that have been undertaken or are planned for to address areas where cumulative energy savings are below plan. For some initiatives where cumulative energy savings are on or above plan, the table includes planned actions to ensure performance is maintained.

Table 7 Mitigating Measures to Address Cumulative Energy Savings Below Plan

Rate Structures	
Industrial Transmission	Cumulative electricity savings in fiscal 2021 were on plan.
DSM Programs	
Residential Sector	
Low Income	Cumulative electricity savings in fiscal 2021 were below plan. As public health measures due to the COVID-19 pandemic subside, ECAP promotion and activity are expected to increase.
Non-Integrated Areas	Cumulative electricity savings in fiscal 2021 were below plan. Providing enabling support to Indigenous Nations places them in a stronger position to advance demand-side management projects in their communities in the future. As public health measures subside, DSM projects are expected to increase.
Retail	Cumulative electricity savings in fiscal 2021 were above plan. Program staff will work closely with partners to examine expected participation levels in fiscal 2022 with recent COVID-19 pandemic related retail activities.
Home Renovation Rebate	Cumulative electricity savings in fiscal 2021 were above plan. New tools continue to focus the program towards the highest consuming electrically heated homes and the creation of registered contractor directories helps customers engage contractors with strong program knowledge.

BC Hydro
Power smart

Residential Energy Management Activities	Cumulative electricity savings were above plan. We are continuing to explore new tools to help customers understand their electricity consumption to determine areas of high use and potential savings.
Commercial Sector	
LEM-C	Cumulative electricity savings in fiscal 2021 were approximately on plan. Going forward, the program will continue to work with customers to remove barriers including providing energy advisors to assist small and medium businesses and working with non-profit housing providers to reduce electricity consumption in multi-unit residential buildings.
New Construction	Cumulative electricity savings in fiscal 2021 were above plan. The program is ramping down.
Industrial Sector	
LEM-I	Cumulative electricity savings in fiscal 2021 were approximately on plan. The program will continue to leverage strategic energy management activities.
Thermo-Mechanical Pulp	The Thermo-Mechanical Pulp program was implemented pursuant to Government direction and was subject to specific criteria and timelines. The deadline for project submission has passed and no further projects are planned through this program.
Capacity Focused DSM	There are no capacity savings in fiscal 2021 as these are pilot initiatives.

5 Conservation and Energy Management KBU Operating Expenditures for Fiscal 2021

BC Hydro's Conservation and Energy Management KBU operating expenditures in fiscal 2021 totalled $533,211.[2] Table 8 presents Conservation and Energy Management KBU operating expenditures in fiscal 2021.

Table 8 Conservation and Energy Management KBU Operating Expenditures for Fiscal 2021

	($000)
Labour	489
Consultants/Contractors/Temp Labour	4
Other	40
Total	**533**

2 DSM operating expenditures are not included in earlier tables.

BC Hydro
Power smart

6 Low Carbon Electrification Expenditures

In accordance with Directive 49 of the F20-F21 RRA Decision, BC Hydro reports on the Low Carbon Electrification expenditures within the DSM Regulatory Account. BC Hydro's Low Carbon Electrification expenditures within the DSM Regulatory Account for fiscal 2021 totalled $4.1 million. Table 9 presents Low Carbon Electrification expenditures allocated to the applicable classes defined in section 4(3) (a), (b), (c) or (d) of the GGRR, including a consolidated table with a break down between the Initial Low Carbon Electrification and BC Hydro Low Carbon Electrification projects and programs.

Table 9 Low Carbon Electrification Expenditures for Fiscal 2020 to Fiscal 2021*

Initial LCE Projects		**Expenditures**		
GGRR Regulation Subsection	Projects	F2020 ($ 000)	F2021 ($ 000)	Total ($ 000)
4(3)(a)	Project 3	$1,418	$158	$1,575
	Project 4	$11,250		$11,250
	Thompson Rivers University		($69)	($69)
4(3)(c)	Translink	$500		$500
Project Total		$13,168	$89	$13,256

BC Hydro LCE Programs		**Expenditures**		
GGRR Regulation Subsection	Programs	F2020[1] ($ 000)	F2021 ($ 000)	Total ($ 000)
4(3)(a)(b)	BC Hydro LCE Program	$3,091	$2,852	$5,943
4(3)(c)	BC Hydro LCE Program	$438		$438
4(3)(d)	BC Hydro LCE Program	$232	$1,184	$1,416
Program Total		$3,761	$4,036	$7,797

Summary of LCE Projects/Programs	**F2020**	**F2021**	**Total**
Initial LCE Projects	$13,168	$89	$13,256
BC Hydro LCE Programs	$3,761	$4,036	$7,797
Total BC Hydro LCE Projects/Programs	$16,929	$4,124	$21,053

* Numbers may not add due to rounding.

Notes:

1 GGRR regulation subsection program totals differ from the F2020 GGRR report due to reclassification of a study within the GGRR subsections. The study was completed and included under the classification 4(3)(a)(b) in the F2020 GGRR report, and then it was subsequently reclassified to 4(3)(c). The completion documentation was submitted by the customer in time for fiscal year end. However, the classification of the file trailed into fiscal 2021, after completion of the F2020 GGRR report. This reclassification does not have a rate or cost recovery impact as the study is maintained as a prescribed undertaking.

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix AA

Attachment 2

Demand Side Management Milestone Evaluation Summary Report F2019

BC Hydro
Power smart

Fred James
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

January 14, 2020

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
2004/05 and 2005/06 Revenue Requirements Application
Commission Decision: Order No. G-96-04, October 29, 2004,
Directive 66 (page 197)

BC Hydro writes to submit its F2019 Demand Side Management Milestone Evaluation Summary Report (**the Report**), dated December 2019 in compliance with Directive 66 (page 197) of the BCUC Decision on BC Hydro's 2004/05 to 2005/06 Revenue Requirements Application, dated October 29, 2004. Directive 66 directs BC Hydro to file the executive summaries of its milestone evaluation reports and full final evaluation reports for all its Power Smart programs.

The Report summarizes the impact evaluations completed during F2019 for the following:

1. B.C. Building Code - Commercial Sector: September 2009 – December 2014;
2. Leaders in Energy Management – Commercial Program: F2013-F2017; and
3. Television Market Evaluation: F2015-F2018.

For further information, please contact Geoff Higgins at 604-623-4121 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

(for) Fred James
Chief Regulatory Officer

st/ma

Enclosure (1)

BC Hydro
Power smart

Demand Side Management Milestone Evaluation Summary Report F2019

December 2019

This page left blank

December 2019

Table of Contents

List of Tables

1.0 Introduction

This report summarizes the milestone evaluations of demand-side management (**DSM**) initiatives completed by BC Hydro in fiscal year 2019 (**F2019**). It is filed in compliance with Directive 66 of the British Columbia Utilities Commission (**BCUC**) decision on BC Hydro's F05/F06 Revenue Requirements Application (dated October 29, 2004), which "*directs BC Hydro to file the executive summaries of its milestone evaluation reports and full final evaluation reports of all its Power Smart programs*" (page 197).

BC Hydro evaluates its DSM initiatives to improve its estimates of realized DSM electricity savings and to improve their effectiveness and efficiency.

DSM evaluation activities are guided by the following six principles:

- Objectivity and Neutrality: Evaluations are to be objective and neutral.
- Professional Standards: Evaluation work is guided by industry standards and protocols.
- Qualified Practitioners: BC Hydro employs qualified staff and consultants to conduct evaluations.
- Appropriate Coverage: BC Hydro strives to achieve defined coverage levels for its evaluation of DSM initiatives.
- Business Integration: The evaluation function is integrated into BC Hydro's DSM business process of planning, implementation, reporting and evaluation.
- Coordination: BC Hydro evaluation work is coordinated with FortisBC and other DSM partners where feasible.

BC Hydro DSM evaluations are subject to an independent oversight process to ensure that they are neutral and unbiased, of sufficient quality for their intended purposes, and consistent with industry standards and protocols.

1.1 Completed Evaluations

Impact evaluations summarized in this report include the following:

- B.C. Building Code - Commercial Sector: September 2009 – December 2014
- Leaders in Energy Management – Commercial Program: F2013-F2017
- Television Market Evaluation: F2015-F2018

2.0 B.C. Building Code - Commercial Sector: September 2009 – December 2014

2.1 Introduction

This report presents the evaluated gross electricity savings associated with the new provincial building code and the Vancouver Building By-law (**VBBL**) requirements for energy efficiency in commercial buildings adopted in September 2008. The scope of this evaluation includes all new[1] commercial and institutional Part 3 buildings,[2] including multi-unit residential buildings (**MURBs**). Gross energy savings associated with the commercial building code were estimated for the period September 1, 2009 to December 31, 2014 (hereinafter, the evaluation period is referred to as F2010 to F2015).

The BC Building Code is a provincial building regulation that applies to the construction of new residential, commercial, institutional and industrial buildings, as well as alterations and additions to existing buildings. The BC Building Code sets forth the minimum standards and rules by which the construction industry must abide.[3] Prior to September 2008, the BC Building Code did not have energy efficiency requirements for new buildings constructed in the province. In September 2008, the province revised the BC Building Code and adopted ASHRAE 90.1-2004 as the minimum acceptable standard for energy efficiency in commercial buildings. Near the end of 2008, the City of Vancouver adopted a by-law whereby the ASHRAE 90.1-2007 standard had to be met.

BC Hydro provides technical assistance and resources to support the research behind implementing and updating building codes for energy in the province. Support activities include participating in technical code committees; working with government stakeholders in order to help negotiate the advancement in the energy requirements of the building code; and developing strategies and testing new approaches to support and advance future building code updates. BC Hydro also designs and implements initiatives to ready the market for energy efficiency regulations. To support the implementation of the BC Building Code in the commercial sector, BC Hydro implemented the Commercial New Construction (**CNC**) program, which provided funding and training to support the advancement of energy efficiency design and offset the cost of more expensive technologies and design.

This study does not attempt to evaluate the influence of BC Hydro's work on building codes on energy efficiency. Instead, the goal is to estimate electricity savings in BC Hydro's service territory due to a reduction in electricity usage by new commercial building stock since the adoption of the ASHRAE 90.1-2004 standard by the BC Building Code (ASHRAE 90.1-2007 by the VBBL) in September 2008. Therefore, this evaluation will estimate only the gross savings. This is the first evaluation of the energy efficiency component of the commercial building code.

1 Savings from additions or alterations to existing buildings were not included due to limited data.
2 Part 3 buildings refer to buildings over three stories in height or with a floor area of over 600 square meters. Examples include shopping malls, office buildings, apartment buildings, schools and restaurants.
3 BC Office of Housing and Construction Standards, June 2015. *Understanding B.C.'s Building Regulatory System*.

2.2 Approach

The evaluation objectives and research questions are shown below in Table 1, followed by the data sources and methods (Table 2).

Table 1 Evaluation Objectives and Research Questions

Evaluation Objective	Research Questions
1. Characterize the new commercial building stock constructed after the building code requirements were changed in 2008	• What types of commercial buildings were constructed after the introduction of the 2008 provincial building code and Vancouver Building Bylaw (VBBL)? • How many square feet of commercial floor space by building type were constructed during each year of the evaluation period? • What was the regional breakdown of new commercial construction stock in the province for the evaluation period?
2. Estimate electricity usage intensity (EUI) savings	• What was the average annual electricity consumption per square foot by building type pre-code (2005-2008) and post-code (2009-2014)? • What were the gross energy savings per square foot by building type for each year of the evaluation period?
3. Estimate gross energy and peak demand savings	• What were the gross electricity savings by building type and year? • What were the total gross electricity savings by year? • What were the gross peak demand savings by building type and year?

The data sources and analytical methods used to address the objectives are summarized in Table 2, followed by a description for each objective.

Table 2 Evaluation Objectives, Data and Methods

Evaluation Objectives	Data	Method
1. Characterize the new commercial building stock constructed after the building code requirements were changed in 2008	Statistics Canada Building Permits Survey (2005-2015) BC Assessment data (2005-2016) BC Hydro account information	Cross tabulations Trends
2. Estimate EUI savings	BC Hydro billing data (F2014-F2018) Commercial New Construction program data Continuous Optimization program data Canada Green Building Council LEED building lists Weather data	Engineering algorithm Weather normalization modelling Billing data analysis
3. Estimate gross energy and peak demand savings	Results for Objectives 1 & 2 Statistics Canada Building Permits Survey (2009-2015) BC Hydro commercial rate class load shape (Peak Demand Ratio)	Engineering algorithm

Objective 1 used data from three different sources to develop and characterize commercial building stock in the BC Hydro service area. The total number of buildings was obtained from the Statistics Canada Building Permits Survey and information about building characteristics was taken from BC Assessment data and BC Hydro account information. Square footage was estimated using permit cost data collected in the Statistics Canada survey and the Hanscomb 2013 *Yardsticks for Costing*. The analysis of characteristics and trends in the commercial building stock was completed by summarizing trends in constructed buildings over time and generating cross tabulations by building type and region.

Objective 2 required estimation of pre- and post-code EUI for each building type to obtain the EUI savings, a key metric in the calculation of gross savings for commercial stock.

Calculating building EUI required using information from different sources:

- BC Assessment (**BCA**) data were used to identify the building type, year of construction and square footage at the building level;
- BC Hydro billing data were used in the calculation of annual electricity consumption at the building level. The following steps were undertaken to estimate the building normalized annual consumption:
    - removal of participants in other BC Hydro DSM program and LEED-certified buildings;
    - adjustments for construction time, occupancy and fluctuations in business operations based on individual building consumption patterns; and
    - normalizing for variations in weather.
- Information from the BC Hydro and BCA data sources was cross-referenced to compile the data necessary to calculate the normalized annual consumption per square foot (i.e., the building EUI).

In addition, calculating the EUI savings involved several steps:

- Develop the samples of buildings to represent the pre-code period and the post-code period using BCA data.
- Analyze the EUI distributions of the pre- and post-code samples for each building type and determine the median EUI[4] for each sample distribution.
- Calculate the difference between the pre- and post-code median EUIs for each building type.

Objective 3 was addressed by multiplying the EUI energy savings for each building type calculated in Objective 2 by the total square footage by building type for each year from F2010 to F2015, and summing up the results. As noted above, electricity savings are gross estimates, and do not include adjustments for attribution to the supports provided by BC Hydro.

2.3 Results

The results of the evaluation are presented by objective.

Objective 1: Characterize the new commercial building stock

The majority of commercial new construction occurred in the Lower Mainland and on Vancouver Island. During the post-code period, the Lower Mainland accounted for 69 per cent of total new buildings and Vancouver Island accounted for 17 per cent. Taken together these two regions account for a total of 86 per cent of the new commercial buildings in the province and 83 per cent of the total square footage.

Multi-Unit Residential Buildings (**MURBs**) represented the majority (81 per cent) of buildings constructed in the post-code period, with the remaining 19 per cent distributed fairly equally among the other building types. MURBs also accounted for the largest share of the total square footage (58 per cent). Offices, retail, warehouses, and other commercial buildings each

[4] The median was used rather than mean due to the variability in the structures, functions, size and electricity consumption of the buildings in the samples. The median is less sensitive than the average (or mean) to extreme values and outliers, and can be a better indicator of central tendency when the distribution is skewed.

accounted for between 7 per cent to 11 per cent of the total floor area, and the remaining 7 per cent was shared by educational facilities, hospitals, hotels and restaurants.

Square footage by building type fluctuated over time and there was no single consistent pattern across building types. The trend in the square footage for MURBs drives the trend in total floor stock, with a large dip occurring in 2009, followed by continuous growth for the remainder of the period. Square footage also increased in retail buildings after 2009, but began to decline after 2011 until 2013 when it began to increase again. Growth in square footage for new warehouse and office buildings did not pick up as quickly as other building types, declining from 2008 to 2010 with peaks occurring in 2011 and 2012, respectively. The other commercial category showed a similar pattern, although it accounted for less floor area.

Objective 2: Estimate electricity usage intensity savings

EUI savings were calculated as the difference between the median EUI for buildings constructed in the pre-code period and buildings constructed in the post-code period.

Table 3 Pre-Code and Post-Code Gross Energy Savings per Square Foot – Electricity Use Intensity

Building Type	Pre-Code EUI (kWh/ft^2)	Post-Code EUI (kWh/ft^2)	ΔkWh/ft^2	Energy Efficiency Improvement (%)
MURB	6.4	5.8	0.6*	9
Office	14.6	11.5	3.1*	21
Retail	17.9	14.3	3.6*	20
Warehouse	9.8	9.2	0.6	6
Other Commercial	7.7	7.2	0.5	7

* Statistically significant at the 95 per cent confidence level. The remaining differences were not statistically significant at the 80 per cent confidence level.

The EUI savings for MURBs, offices, and retail buildings were statistically significant, while the results for warehouse and other commercial building types were not, due to the small number and diversity of the buildings in these two groups. There was no sample with which to conduct the EUI analysis for education, hospitals, and hotels/restaurants building categories, because the BC Assessment data was poor for these categories. Therefore, the EUI savings for these three building types were based on the engineering modelling analysis used to derive the reported gross savings.

Objective 3: Evaluated gross energy and peak demand savings

The evaluated gross energy savings for each building type in each fiscal year covered by the evaluation period are presented in Table 4. Reported savings were calculated based on a projection of annual growth in commercial floor stock and engineering estimates of EUI savings. Evaluated savings were based on actual floor stock of newly constructed buildings and EUI savings estimated from actual building electricity usage intensity data. Evaluated gross electricity savings ranged from 11 GWh/year to 30 GWh/year from F2010 to F2015, with the most savings occurring in F2013 and the least occurring in F2010. The high savings achieved in F2013 reflects the surge in savings that year for office buildings. Retail buildings had the highest total gross electricity savings (46.4 GWh/year) of all building types, followed by MURBs (29.9 GWh/year) and office (28.9 GWh/year).

Table 4 Summary of Reported and Evaluated Gross Energy and Peak Demand Savings

Calendar Year	Energy Savings (GWh/year)		Peak Demand Savings (MW)	
	Reported	Evaluated Gross	Reported	Evaluated Gross
F2010	10	11	1	2
F2011	18	24	3	4
F2012	16	23	2	4
F2013	17	30	2	5
F2014	17	22	2	4
F2015	18	23	3	4
Total	**96**	**132**	**14**	**21**

The cumulative variance between the reported energy savings and evaluated energy savings was 36 GWh/year. The largest variance occurred in F2013 with a difference of 13 GWh/year between reported and evaluated savings. The evaluated savings for MURBs, offices, and retail buildings were all higher than reported savings for a combined variance of 44.2 GWh/year. For MURBs, the EUI savings were over twice the value assumed in reported savings and the floor stock was 10 per cent higher than was forecast. Offices and retail buildings also had larger than reported EUI savings, although the new floor stock in these categories was only about half the forecasted value. Education buildings were responsible for the largest negative variance at -6.7 GWh/year, mainly due to a smaller floor stock than anticipated in reported savings.

2.4 Findings and Recommendations

Findings

1. The majority of building permits were issued in the Lower Mainland (69 per cent), followed by Vancouver Island (17 per cent). Based on the relative total square footage of these buildings, those constructed in the Lower Mainland were larger than those constructed on Vancouver Island.

2. The increasing trend in building permits that occurred after 2009 was driven by the increasing construction of MURBs, which accounted for the largest percentage of new buildings (81 per cent) during the post-code period. MURBs also accounted for the largest share (58 per cent) of total square footage.

3. Billing data revealed an average lag of approximately one year from permit issuance to construction completion. In addition, MURBs and office buildings had high vacancy rates during the first year after construction completion (i.e., the second year after permit issuance). From the third year onward, these two building types averaged an occupancy rate estimated at approximately 97 per cent annually.

4. The EUI savings estimated for each building type suggested that building performance improved after the code, improving energy efficiency by 9 per cent for MURBs, 21 per cent for office buildings and 20 per cent for retail buildings. Improvements in building performance for the warehouse and other commercial buildings categories were not statistically significant.

5. The evaluated gross energy savings and the corresponding peak demand savings from F2010 to F2015 were 132 GWh/year and 21 MW, respectively. The highest savings

were achieved in F2013, reflecting the spike in building permits for office development in 2012, taking into consideration the 12 months construction period.

6. The evaluated gross electricity savings were 36 GWh/year higher than the reported gross savings of 96 GWh/year. The largest difference occurred for MURBs, where the EUI savings were over twice the value assumed in reported savings and the floor stock was 10 per cent higher than was forecast. Offices and retail buildings also contributed to the positive variance through larger than reported EUI savings, although the new floor stock in these categories was only about half the forecasted value.

Recommendations

The following recommendations flow from the findings of this evaluation. Recommendation #1 is for the BC Hydro Codes and Standards group. Recommendation #2 is for Evaluation.

1. For MURBs and office buildings, consider adding another 12 months of lag time for reported savings to the 12 months already allowed for building construction to allow the building to achieve typical occupancy levels, or somehow account for partial occupancy during that period.
2. If cost-effective, consider using a combined approach in future evaluations of building code to include calibrated engineering simulation analysis for some building types where data is scarce, with the understanding that there will only be billing data for 12 months after building completion or typical occupancy levels.

2.5 Conclusions

The commercial building stock in B.C. became more energy efficient after energy efficiency was included in the 2008 BC Building Code. The greatest energy savings were achieved in retail buildings, followed by offices and MURBs.

3.0 Leaders in Energy Management – Commercial Program F2013-F2017

3.1 Introduction

This report presents the results of an impact evaluation of the BC Hydro Leaders in Energy Management – Commercial (**LEM-C**) program for BC Hydro fiscal years F2013 to F2017 (April 2012 to March 2017).

The LEM-C program targets BC Hydro's commercial segment, which consists of organizations in both the public and private sectors. The target market includes large customer organizations with combined annual electricity consumption greater than 4.0 GWh and small- and medium-sized businesses (**SMBs**) with annual electricity consumption less than 4.0 GWh. LEM-C is a comprehensive program that provides a suite of offers, tools and other assistance intended to help commercial customers implement energy-saving projects while also building energy management activities into their standard business practices over the long term.

During the evaluation period, the custom component of the program provided incentives to large commercial customers to implement energy efficiency projects. Incentives were determined on a per project basis based on its estimated energy savings and capital costs. Savings could also be achieved through program-enabled projects. These are custom projects that did not receive direct capital incentive funding from BC Hydro, but were enabled by other BC Hydro resources and supports, such as energy managers, energy study funding, Key Account Managers (**KAMs**) for large customers[5], and Business Energy Advisors (**BEAs**) for small- and medium-sized customers. Prescriptive incentives (Business Energy Savings Incentives or **BESI**[6]) were available to commercial customers of any size and covered simple, one-for-one replacements of inefficient technologies with energy-efficient ones, most commonly lighting. During the five-year evaluation timeframe, 4,865 energy efficiency and conservation projects implementing 17,365 energy conservation measures were completed at 5,561 unique sites of 1,460 parent organizations.

LEM-C also delivered initiatives designed to change attitudes, behaviours and practices within its large commercial customer organizations. The program undertook a strategic energy management approach designed to assist large customers with managing their energy consumption by planning for and tracking changes in consumption; adopting energy efficiency policies; implementing operational and maintenance changes; completing energy retrofits of existing buildings; changing employee behaviours; and assisting customers to integrate strategic energy management into their ongoing business practices and corporate culture. To support the adoption of strategic energy management, large commercial organizations had access to funding to hire qualified energy managers and conduct energy studies. Maintaining a qualified energy manager workforce was supported through BC Hydro-provided education and training. Funding through the Workplace Conservation Awareness (**WCA**) initiative was also available and aimed to harness employee engagement as a way to save energy and to establish a permanent culture of energy conservation within the organization.

5 Large customers are defined as organizations with electricity consumption of greater than 4 GWh per year.
6 Formerly known as Power Smart Express (**PSX**) until late F2016.

3.2 Approach

The evaluation addressed five objectives each with related research questions, as presented in Table 5.

Table 5 Evaluation Objectives and Research Questions

Evaluation Objective	Research Questions
1. Assess the customer experience with LEM-C program design and delivery	What are participant and non-participant experiences related to program awareness, understanding, and satisfaction for each of the program offers (custom, program enabled, and prescriptive)? Is there a difference between customers with and without a Key Account Manager? What are the main drivers of and barriers to program participation?
2. Assess the extent to which project-enabling activities supported the implementation of energy efficient projects and practices	What types of project-enabling activities were undertaken by the different customer segments? What factors had the greatest association with amount and type of project activity (e.g., energy managers, energy studies, KAM/Alliance/BEA involvement)? Was there a difference across commercial customer segments (e.g., public versus private sectors) and over time? To what extent and in what ways did BEAs influence project activities for small- and medium-sized businesses? To what extent are energy managers and energy studies associated with project activity and savings overall and over time? How much program-provided training and education was accessed by energy managers? How did the training affect the implementation of energy efficient projects and practices? What kinds of program-provided tools and resources were accessed by participants (e.g., SharePoint, webinars, training, others)? How did the tools and resources affect the implementation of energy efficient projects and practices? What kind of influence did customer recognition/appreciation advertising activities have on participating organizations (e.g., number and type of projects, energy savings, behaviour/attitude)?
3. Assess the extent to which strategic energy management practices were integrated into on-going business activities	What types of strategic energy management practices were integrated into business activities? Were there differing degrees of integration across customer groups (e.g., with/without KAM; public versus private sector; organization size or type)? Is there any evidence of activities or energy savings resulting from the expanded energy manager market (e.g., non-BC Hydro funded energy managers)? What are the similarities/differences in strategic energy management practices of participating organizations as compared to similar non-participating organizations?
4. Estimate gross electrical energy and peak demand savings	What were the evaluated gross energy and demand savings by fiscal year, and by custom (incentives, program enabled) and prescriptive (e.g., BESI) offers? What were the gross realization rates[7] by offer, and by end use (to the extent possible)?
5. Estimate net electrical energy and peak demand savings	How much free ridership occurred for the custom and prescriptive offers? How much participant spillover occurred for the custom and prescriptive offers? How much non-participant spillover occurred for the custom and prescriptive offers? What are the evaluated net energy savings and demand savings by fiscal year and by offer?

7 The ratio of initial estimated savings to savings adjusted for data errors and measurement and verification results.

The data sources and analytical methods used to address the objectives are summarized in Table 6.

Table 6 Evaluation Objectives, Data Sources and Methods

Evaluation Objectives	Data	Method
1. Assess the customer experience with LEM-C program design and delivery	• 7 waves of program participant surveys covering F2013 to F2017 (n=686) • 1 wave of a non-participant survey covering F2014 to F2015 (n=349) • Trade allies survey F2015 (n=88)	• Cross tabulations
2. Assess the extent to which project-enabling activities supported the implementation of energy efficient projects and practices	• Program administrative records • Participant survey BEA questions (n=17) • 6 waves of Energy Manager surveys covering F2015 to F2017 (n=7 to n=45 per wave) • Participant interviews (n=10)	• Cross tabulations • Qualitative analysis
3. Assess the extent to which strategic energy management practices were integrated into on-going business activities	• Energy Management Assessment reports • Participant interviews (n=10) • KAM interviews (n=8)	• Descriptive quantitative analysis • Qualitative analysis
4. Estimate gross electrical energy and peak demand savings	• Program tracking data • Project files • Measurement and Verification results (n=999 measures)	• Extrapolation of Measurement and Verification results using stratified ratio estimation • Average peak-to-energy factors
5. Estimate net electrical energy and peak demand savings	• Results from Objective 4 • 7 waves of participant surveys covering F2013 to F2017 (n=686) • 1 wave of non-participant survey covering F2014 to F2015 (n=349)	• Survey-based free ridership and spillover algorithms • BC Hydro Standard Procedure for Cross Effects

3.3 Results

Results for Objective 1: Asses the customer experience with LEM-C program design and delivery

Awareness of the LEM-C offers was highest among custom participants at 93 per cent. Awareness was lower among prescriptive KAM and non-KAM participants at 79 per cent each. For non-participants, awareness of the program among customers eligible to participate in the custom offer was 74 per cent and much lower among customers eligible to participate in only the prescriptive offer at only 36 per cent. In terms of individual program components, among participants, awareness was highest for the role that KAMs play as liaisons for the program and for the prescriptive offer, and lowest for the custom incentive structure and the energy manager offer. Among non-participants, awareness was low for all of the individual program offers.

Overall satisfaction (somewhat plus very satisfied) was very high for all of the LEM-C offers at 95 per cent for custom participants, 88 per cent for prescriptive KAM participants and 92 per cent for prescriptive non-KAM participants. In terms of program experience, services provided by contractors and suppliers/distributors were both rated highly – above 80 per cent rated them as excellent or good – among all participant groups. Installing the energy efficient technology and the quality of the energy efficient technology were also both rated highly by all groups. Knowing how/who to contact was rated particularly highly by custom participants (90 per cent), but lower among both prescriptive KAM participants (68 per cent) and prescriptive non-KAM participants (56 per cent). Areas which rated lowest included direct mail/email about the program (for all offers), length of time to receive project approval (for custom), information about the program on the website (for custom), pre- and post-inspections (for prescriptive KAM), variety of products funded under the program (for prescriptive non-KAM), knowing how/who to contact at BC Hydro (for prescriptive non-KAM) and usability of the online application (for prescriptive non-KAM).

Among all groups, the factor that emerged as the greatest motivator to managing electricity was making operating costs as low as possible. This sentiment was echoed in the participant interviews with saving money noted as the primary motivator. Among the participant groups, the individual program offers were also motivators, as were energy managers and KAMs. Among both participants and non-participants, the largest barriers to managing electricity use were lack of funds for energy efficient retrofits, other operational priorities, and lack of financial incentives. Among non-participants, the main reason for not participating was that they needed more information about the program.

Results for Objective 2: Assess the project-enabling activities

More than half (55 per cent) of the organizations that participated in LEM-C had an energy manager or energy study. Just over one-quarter (27 per cent) had both. Public sector organizations were most likely to have had coverage by either an energy manager or energy study or by both. Interview results revealed that organizations highly value the role of the energy manager and that energy studies have been critical for identifying potential projects and creating a business case for energy management activities.

Analysis of program data showed that most of the expected savings were associated with either an energy manager (70 per cent) or an energy study (65 per cent), and often both (55 per cent). The highest percentage reduction in energy for organizations with energy managers compared to organizations without an energy manager occurred in healthcare, government and advanced education. Municipalities, property management, and retail organizations with energy managers, compared to those without an energy manager, showed the least difference in energy reduction, indicating that enabling activities may have less of an impact in these sectors.

Interviews with representatives of participating organizations and with KAMs indicated that energy managers are critical to facilitating and supporting the implementation of custom and prescriptive projects, as well as facilitating the adoption of strategic energy management practices.

In the interviews, respondents generally highlighted that Key Account Managers were critical to the success of their energy management activities as they facilitated communication between BC Hydro and the respondent’s organization, endorsed the credibility of the energy managers to senior management and assisted with funding applications. Among survey respondents who had used the BEA service, 41 per cent indicated that they would not have completed the project without the assistance of the BEA, while 35 per cent would have completed it on their own and the remaining 24 per cent were unsure. Satisfaction was high among those who used a BEA, with 82 per cent giving it a score of 8, 9 or 10 on a 10-point scale.

BC Hydro provided a comprehensive training plan to support energy managers in achieving conservation goals, including training sessions, on-line webinars as well as Energy Manager Forums. Interviews with Energy managers suggest that the training provided was generally viewed favourably by the energy managers. More experienced energy managers noted that training on BC Hydro’s administrative process requirements became less important with increased experience. Surveys conducted with energy managers revealed their levels of satisfaction with training sessions and the Energy Manager Forum to range between 7.5 to 9.0 on a 10-point scale.

Results for Objective 3: Assess strategic energy management practices

Among the participating organizations interviewed, there was generally a high level of commitment to strategic energy management. Most had been doing strategic energy management for several years and some processes had become embedded in the organization practices. Many reported having year-on-year targets that are reported and updated on an annual basis, and energy planning activities integrated into the capital planning process. Energy studies were a means used to identify potential projects. In contrast, KAMs interviewed indicated that, to their knowledge, non-participating organizations typically did not consider energy efficiency in their capital planning exercises. Instead these organizations took a more tactical approach, relying on funding for discrete projects on an ad hoc basis.

A number of interviewed participants identified operating practices as integral to strategic energy management activities and something that the energy managers had significant ability to influence. It was noted, however, that while the level of awareness related to energy management had increased within organizations, operational staff may not be fully engaged nor committed to energy management.

Most participating organizations conceded that in the absence of the BC Hydro program, the level of strategic energy management activity would diminish.

Energy Management Assessments (**EMAs**) are a diagnostic workshop conducted every two years to track progress in organizational adoption of strategic energy management. Analysis of EMA index scores dating back to F2006 revealed that as many as nine EMA sessions had been completed (one organization), although it was most common for organizations to have engaged in four to six sessions. The overall scores increased from an average of 0.9 to 1.5 after five sessions, moving these organizations as a whole from a tactical approach to energy management (scores in the 0.0 to 1.0 range) to a more strategic approach (scores in the 1.01 to 2.0 range). A few organizations achieved overall scores greater than 2.0, signifying that strategic energy management had been operationally integrated into business practices at the time of the assessment. Scores in the private sector tended to be higher and improved by a greater margin than those in the public sector. Within the private sector, the property management sector had the fastest progression, increasing from an average score of 1.0 to 2.2 after five sessions. Within the public sector, colleges and universities had the fastest progression, increasing from 0.9 to 1.7, after five sessions. Municipalities had the slowest progression, starting at an average score of 0.8 and increasing to 1.3 after five sessions.

Results for Objective 4: Estimate gross electrical energy and peak demand savings

Gross energy savings were determined from three end use samples of projects with M&V and extrapolated to the remaining projects in the population. The sample for realization rate estimation was comprised of projects accounting for 21 per cent of expected energy savings (statistically significant coverage). Once the three samples for realization rate estimation were established, stratified ratio estimation was applied.

LEM-C projects typically involved lighting and could be categorized as Light Emitting Diode (**LED**) lighting, non-LED lighting and other end uses. There was virtually no difference in the realization rate across the three types of end uses. The distribution of energy conservation measures and energy savings for the three end uses, tag-on[8] savings and program enabled (**PE**) projects where savings are assumed to persist for two years or less are shown in the table below.

---

8 Tag-on savings are customer-funded activities that improve energy efficiency, which were recognized and reported by the program during post implementation review of custom lighting projects only. These savings are in addition to estimated spillover savings.

Table 7 Gross Realization Rates and Evaluated Energy Savings and Peak Demand Savings by End Use and Offer

End Use and Offer	Measure Count	Expected Savings (GWh/year)	Gross Realization Rate	Evaluated Gross Energy Savings (GWh/year)	Gross Peak Demand Savings (MW)
LED Lighting	7,695	162	**0.97**	158	25
Non-LED Lighting	7,014	103	**1.00**	103	16
Other End Uses	1,555	93	**0.96**	90	13
Tag-on Savings	n/a	7.3	Not evaluated	7.3	1
PE with ≤ 2 years savings persistence	1,101	42	Not evaluated	42	6
Overall Program	17,365	408	0.98	400	61

Objective 5: Estimate net electricity savings

Net electricity savings are the change in energy consumption and demand that is attributable to the program. They exclude free riders and include spillover. Free ridership was estimated separately for the three types of projects reported by the program: custom, prescriptive KAM and prescriptive non-KAM. The overall level of free ridership was estimated at 17 per cent for the program, ranging from 14 to 22 per cent between program offers. Participant spillover was estimated at 12 per cent and non-participant spillover was estimated at 7 per cent, for a total of 19 per cent. Together they result in a net-to-gross ratio of 102 per cent. Cross effects were calculated as 4 per cent for custom, 4 per cent for prescriptive KAM and 5 per cent for prescriptive non-KAM projects, for a downward adjustment of the evaluated gross energy savings of 13 GWh/year during the evaluation period. Evaluated net energy and peak demand savings[9] are shown in Table 8 and averaged 111 per cent of reported savings, showing that the program performed better than reported.

Table 8 Summary of Energy and Peak Demand Savings

Calendar Year	Net Energy Savings (GWh/year)		Peak Demand Savings (MW)	
	Reported	Evaluated	Reported	Evaluated
F2013	90.3	93.8	13.8	14.3
F2014	65.2	76.0	10.0	11.6
F2015	59.7	64.2	9.1	9.8
F2016	63.9	75.4	9.8	11.5
F2017	76.9	85.9	11.8	13.1

The variance between reported and evaluated net savings is primarily due to the evaluated net-to-gross ratio being higher than what was assumed for reported savings. The results reflect the continuous improvement approach taken by LEM-C program managers whereby the findings from previous impact and process evaluations were used to make adjustments to business planning assumptions, program design and delivery.

9 A conversion factor derived from load shape analysis used in DSM planning was applied. The factor was a weighted average of commercial lighting and other peak-to-energy factors for the period from F2013 to F2017.

3.4 Findings and Recommendations

Findings

Customer Experience with Program Design and Delivery

1. Overall satisfaction (somewhat plus very satisfied) was very high for all of the LEM-C offers at 95 per cent for custom participants, 88 per cent for prescriptive KAM participants and 92 per cent for prescriptive non-KAM participants.
2. Services provided by contractors and suppliers/distributors were both rated highly among all participant groups, as were installing the energy efficient technology and the quality of the energy efficient technology. Aspects with the lowest ratings were direct mail/email about the program, length of time to receive project approval (for custom participants), pre- and post-inspections (for prescriptive KAM participants) and variety of products funded under the program (for prescriptive non-KAM participants).
3. Among all groups, the factor that emerged as the greatest motivator to managing electricity use was making operating costs as low as possible. The largest barriers were lack of funds, other operational priorities, and lack of financial incentives.

Project-enabling Activities

4. The majority of projects (68 per cent) and expected savings (79 per cent) of organizations with annual consumption of 4 GWh per year and greater had an energy manager and/or had completed an energy study. Public sector organizations were most likely to have had coverage by either an energy manager or energy study or both, particularly healthcare, advanced education and school districts. Private sector companies had lower levels of coverage.
5. Overall, organizations with BC Hydro-funded energy managers were found to have completed more than twice the number of projects compared to organizations without an energy manager. To assess the effectiveness of energy managers and account for differences in consumption, energy savings relative to annual consumption in F2017 were examined. The results revealed greater proportional savings for organizations with an energy manager (11 per cent) than those without (8 per cent).
6. All energy managers were required to participate in training relevant to their respective sectors, which they generally viewed favourably. The energy managers interviewed noted that the training was most useful in the first years of participation, but became less relevant to their needs over time. The same was true for the various tools and templates provided by the program. Energy managers highly valued the Energy Manager Forum for knowledge transfer and sharing of ideas among their peers.
7. Business Energy Advisors conducted visits to approximately 500 commercial sites of which about 100 went on to complete projects with associated savings totaling approximately 4 GWh/year. Survey respondents identified energy saving opportunities (88 per cent) and being introduced to available incentives from BC Hydro (71 per cent) as the most valuable aspects of the BEA service.

Integration of Strategic Energy Management Practices

8. Overall, average EMA scores increased over time, with most organizations moving from a tactical approach (scores in the 0.0 to 1.0 range) to a more strategic approach (scores in the 1.01 to 2.0 range). A few organizations achieved assessment scores above 2.0, signifying that energy management had been operationally integrated into corporate

practices. None of the organizations had moved to a continuous improvement approach (i.e., scores above 3.0 range) where strategy energy management would be highly integrated into the corporate culture. Private sector organizations tended to score higher and improved by a greater margin than public sector organizations.

9. Organizations with an energy manager tended to be further ahead in integrating strategic energy management practices within the corporate planning process than those without one. Representatives of participating organizations noted that, if left without an energy manager, the level of strategic energy management would drop off. Organizational barriers to fully integrating strategic energy management included lack of senior management support and low engagement of operations staff.

10. Non-participating organizations did not typically set targets or incorporate energy efficiency into their corporate planning or policies. The exception was large institutions and national private sector organizations that already have a 'green' culture in place, and these typically have professional staff to implement strategic planning and policies.

Gross Electrical Energy Savings

11. The program gross realization rate calculated using the M&V results was 0.98, indicating that the energy conservation measures largely performed as expected. The realization rates by end use were 0.97, 1.0 and 0.96 for LED lighting, non-LED lighting and other end-uses, respectively.

12. Expected energy savings averaged 10 per cent of site energy consumption across all participants during the five-year evaluation period.

Net Electrical Energy Savings

13. The net-to-gross ratio excluding cross effects was 102 per cent based on an overall level of free ridership of 17 per cent, participant spillover of 12 per cent, and non-participant spillover of 7 per cent. Cross effects were 3.4 per cent.

14. Evaluated net savings during the evaluation period from F2013 to F2017 averaged 111 per cent of reported savings.

Recommendations

The following three recommendations are for the BC Hydro LEM-C program managers based on the findings of this evaluation.

1. Review and adjust project-enabling supports, such as training and knowledge sharing to reflect the changing needs of more experienced energy managers and mature organizations with regards to strategic energy management.

2. Develop a better understanding of building operators' responsibilities, capabilities and training needs in order to better support their role in strategic energy management.

3. Improve consistency of linking energy manager, energy study and other enabling activities at the organization level to individual sites and projects in the program administrative database.

3.5 Conclusions

The BC Hydro's LEM-C program achieved 11 per cent more savings during fiscal years F2013 to F2017 than was expected. Energy managers and energy studies lead to enhanced strategic energy management practice and energy savings in participating organizations. The program also achieved high levels of customer awareness and satisfaction.

4.0 Television Market Evaluation F2015-F2018

4.1 Introduction

This is a market evaluation that examines changes in the market for new televisions in B.C. in the context of 2013 and 2015 provincial regulations for TV energy efficiency. The evaluation estimates the electricity savings in BC Hydro's service territory due to changes in the efficiency of TVs sold in B.C. from F2015 to F2018, which includes the influence of provincial TV regulations operating in the context of external drivers and the evolving global TV market. Trends in B.C.'s TV market are examined over a longer period, from the fourth quarter of F2010 to the end of F2018. The evaluation does not attempt to determine the share of savings directly attributable to changes in regulation or other specific actions.

The market for TVs is a global one that evolves over time in response to competition among manufacturers, technology developments and consumer preferences, government policies like energy efficiency standards and regulations, and utility energy conservation programs. The energy efficiency of TVs sold in B.C. is a product of this evolution and the underlying drivers. Some of the drivers that influence the efficiency of TVs sold throughout North America are external to B.C., such as Energy Star standards that influence TV manufacturers and energy efficiency regulations in Canada, California and other states in the U.S. Other drivers of market change are internal to B.C., such as BC Hydro's demand side management programs and the B.C. TV regulation.

BC Hydro demand side management programs targeting the TV market were available from F2009 to F2014, which is prior to the evaluation period.

The B.C. TV regulations establish maximum limits for TV power draw. The first B.C. energy efficiency regulation for TVs took effect in January 2012 for power draw in on mode only, followed by limits for power draw in standby and off modes.

4.2 Approach

Shown on the below are the evaluation objectives and research questions, followed by the data sources and methods.

Table 9 Evaluation Objectives and Research Questions

Evaluation Objective	Research Questions
1. TV market demand-side assessment	What are the trends in TV ownership among residential customers? What are the trends in TV usage among residential customers? What are the principal factors contributing to consumers' TV purchase decisions? How important is energy efficiency of TVs for customers? Has the level of importance changed over the years?
2. TV market supply-side assessment	What were annual sales of TVs in B.C. from F2011 to F2018? What were the trends in the characteristics (e.g., new technologies, screen size) of new TVs from F2011 to F2018? What were the trends in the energy efficiency of TVs sold from F2011 to F2018? What was the level of compliance with the regulations among TVs sold from F2011 to F2018?
3. Gross electricity savings	What were the overall electricity and peak demand savings due to changes in the B.C. TV market from F2015 to F2018?

Table 10 Evaluation Objectives, Data and Methods

Evaluation Objectives	Data	Method
1. TV market demand-side assessment	• Residential End Use Surveys (up to 2017) • 2016 Consumer Electronics Survey • Retailer interviews (n=2) • Regulator interviews (n=2)	• Frequencies; cross tabulations • Trend analysis • Qualitative analysis
2. TV market supply-side assessment	• Quarterly TV sales data for B.C. (F2010 - F2018) • Annual Electronics Floor Stock Study (2010 to 2017) • Online product information • Regulator interviews (n=2) • Retailer interviews (n=2)	• Trends analysis • Descriptive statistics • Frequencies; cross tabulations • Qualitative analysis
3. Gross electricity savings	• Quarterly TV sales data for B.C. (F2010 to F2018) • 2010 Residential Monitoring Study (48 homes) • 2015 Consumer Electronics Metering Study (53 homes)	• Engineering algorithms

Objective 1 entailed a quantitative analysis of survey results to examine trends in the TV stock installed in BC Hydro customers' homes and factors involved in TV purchasing decisions. Qualitative information obtained through retailer interviews supplemented the survey results regarding trends in factors influencing TV purchases.

Objective 2 was addressed through several steps.

- Estimate TV sales in the BC Hydro service territory by quarter for the period January 2010 through March 2018.
- Determine power draw by model for all TVs sold from F2015 to F2018.

- Apply hours of use estimates from two metering studies of non-random samples of homes.
- Estimate electricity consumption per unit and per square inch by model for all TVs sold.
- Estimate average unit electricity consumption for the entire market.
- Conduct qualitative analysis of interviews with retailers and regulator representatives to explore the regulatory environment and current trends in the TV market.

Objective 3 was addressed using engineering algorithms that compared the market average energy consumption of TVs sold in the base period (defined as January to March 2010), to the market average energy consumption of TVs sold in each year from F2015 to F2018. Electricity savings were adjusted for cross effects and the proportion of the residential population in B.C. that is served by BC Hydro. As noted above, electricity savings are gross estimates, and do not include adjustments for attribution to the B.C. TV regulation or other influences.

4.3 Results

The results of the evaluation are presented by objective.

Objective 1: Demand-side Assessment

As of 2017, the majority of households in the BC Hydro service area (95 per cent) had at least one TV that was being used at least occasionally, with the average household using two sets. Reflecting the rapidly changing TV market, the type of TV installed in BC Hydro customers' homes has changed substantially over the past ten years. The most noteworthy change has been the replacement of the previously standard CRT TV by LCD TVs, and now by LED TVs. The rapid decline of the CRT TV is particularly evident, plummeting from 98 per cent of households in 2001 to 10 per cent of households in 2017. This decline was accompanied by a rapid increase in LCD and LED models, going from 8 per cent of households in 2006 to 85 per cent in 2017.

In the Consumer Electronics survey, customers who had recently purchased a TV (n=38) were asked to identify the most important factors in making their TV purchase decisions. Price emerged to be the most important factor, with 59 per cent of respondents selecting price as one of the top three factors, followed by size (34 per cent) and picture quality (29 per cent). Energy efficiency was indicated as one of the top three factors by 14 per cent of respondents—less important than other features, but more important than brand and manufacturer's warranty. Caution should be used interpreting these results due to the small sample size.

Interviewees representing retailer and regulator perspectives suggested that the importance of energy efficiency in TVs to consumers' purchase decisions has changed over time as technology has progressed and TVs have become more energy efficient. Energy efficiency of the older, mostly obsolete CRT models that dominated the market until around 2003 was thought to matter more to consumers than the efficiency of the newer types of TVs now available, and picture quality has become increasingly important.

Objective 2: Supply-side Assessment

Total annual TV sales peaked in F2012 at 530,336 units.[10] After that, there was a declining trend in the number of TVs sold until F2017 which saw an increase of 10 per cent over F2016. The number of TVs sold in F2017 and F2018 appeared to stabilize around 355,000.

It is well recognized that TV technology has advanced rapidly over the past five to ten years. The functionality of TVs has advanced with application-loaded Smart TVs becoming the norm and connectivity to the internet becoming increasingly important.

Results of the annual floor stock study reveal that Organic LED (**OLED**) and Ultra High Definition (**UHD**) TVs have a greater showroom presence than in previous years. From 2014 to 2017, the percentage of LED-HD TVs displayed in retailer showrooms fell from 85 per cent to 52 per cent, while UHD models increased from 18 per cent in 2015 to 44 per cent in 2017. Recent advances in the LED technologies, such as OLED, QLED (Quantum Dot LED) or UHD[11], provide higher image quality on larger screens sizes and have higher power draw.

As explained by the interview participants, advances in TV display technology have generally led to gains in energy efficiency over the years. Consumption per square inch of screen decreased four-fold from the end of F2010 to the end of F2014, levelling off in F2016 to around 120 W per year per square inch. However, although the new technologies are more energy efficient than the old CRT technology, TV power draw increases with screen size. The TV sales data for B.C. shows that TVs with smaller sized screens (i.e., 40 inches or less) are being replaced with larger sized screens. At the end of F2010, 8 per cent of TVs sold had a screen size of greater than 50 inches as compared to 35 per cent of sales at the end of F2018.

Overall, there has been a general decline since F2014 in the proportion of TVs sold in B.C. that are Energy Star rated. The reason for this trend cannot be ascertained by the evidence used in this evaluation. However, during the interviews, retailer and regulator representatives indicated that the test procedures for measuring the energy efficiency of TVs are not well-suited to some of the new technologies or functionalities, such as network connectivity, making it difficult to apply energy efficiency standards in the same manner as has been done historically.

As noted earlier, from F2011 to F2018, there were three versions of the TV regulation for energy efficiency in B.C. The previous evaluation of the TV market conducted a detailed examination of compliance with the province's 2013 TV regulation. In general it was found that the share of TVs that met or exceeded the efficiency level specified by the 2013 regulation increased over the period from F2010 to F2014. By the first quarter of 2012, immediately following the regulation taking effect, compliance had reached 92 per cent climbing to 97 per cent by the fourth quarter of 2014. The current evaluation period encompasses the change to the regulation implemented in 2015, which dropped the limit on power draw in on mode. The high rate of compliance to the regulation continued through to the end of F2018, reflecting the fact that most TVs complied with the limit on power draw in standby and off modes that remained in the regulation. Analysis revealed a steady decline in the percentage of TVs sold that met the previous limit on power draw in on mode.

10 Note that BC Hydro serves approximately 1.7 million residential accounts. Sales levels of 0.5 million per year imply that most BC Hydro residential customers had purchased at least one new TV between F2011 and F2014. The higher sales in F2011 and F2012 are most likely related to the switch from analog to digital broadcasting that began in 2010 and possibly the desirability of the new LCD/LED technology that was entering the market.

11 Note that Ultra High Definition models are also based on LED technology, while LED refers to standard High Definition models.

Objective 3: Gross Electricity Savings

The reported and evaluated gross electricity energy and peak demand savings are presented in Table 11.

Table 11 Summary of Energy and Peak Demand Savings

Fiscal Year	Gross Energy Savings (GWh/year)		Peak Demand Savings (MW)	
	Reported	**Evaluated**	**Reported**	**Evaluated**
F2015	64	50	15	12
F2016	65	45	15	11
F2017	69	42	16	10
F2018	64	33	15	8

Evaluated savings were 93 GWh/year less than the reported savings for the four year evaluation period. The evaluated gross savings were consistently lower than the reported savings, and the gap increased every year. In F2015 evaluated savings were 14 GWh/year lower than the reported savings for that year, followed by a gap of 20 GWh/year in F2016, 28 GWh/year in F2017 and 31 GWh/year in F2018.[12]

The main factors contributing to the variance between reported and evaluated savings are hours of use and annual sales figures. Reported savings were estimated based on 5.6 hours/day while evaluated savings used 5.0 hours/day based on more recent data. Projected TV sales used for reported savings were consistently higher than actual sales, by 11 per cent to 32 per cent depending on the year. By adjusting the assumptions used to calculate reported savings, it was estimated that, together, these two factors account for approximately 72 per cent of the variance.

The remaining 28 per cent of the variance can be attributed to several recent changes to TV characteristics, in particular the increase in screen size over the four year period and the introduction of slightly less energy efficient technology, both of which appear to have had the greatest impact in F2018. Note that increasing screen size has a negative influence on estimated savings because the baseline was taken as the market average consumption of models sold in F2010, which were on average smaller in size. A baseline that would have accounted for the steady trend of increasing screen size would produce a different result and larger savings.

Standby mode consumption was low (most were less than 0.5 watts per unit) and consistent across the evaluation years, and therefore, contributed only marginally to the variance.

[12] Differences from the above table are due to rounding.

4.4 Findings and Recommendations

Findings

Below are the main evaluation findings.

Demand Side Assessment

1. The type of TV installed in BC Hydro customers' homes has changed dramatically over the past ten years, reflecting the rapid changes in TV technologies. The most noteworthy change has been the move away from standard CRT TVs to LCD TVs and then to LED TVs.
2. Survey results for recent purchasers of new TVs revealed the top three drivers of TV purchase decisions to be, in order of importance: price, screen size, and picture quality. Energy efficiency was rated as a top consideration by only 14 per cent of survey respondents. These results were confirmed in interviews with TV retailers and regulators.

Supply Side Assessment

3. Overall, new TV sales have declined since 2012 and sales appear to have plateaued in F2017 and F2018.
4. The new TV market continues to change rapidly with the introduction of new technologies such as Smart TVs and Ultra High Definition.
5. New TV technologies are more efficient than the old CRTs, but larger screen sizes and improved picture quality require greater power. Therefore, although power draw per square inch has declined dramatically since 2010, the overall power draw of a television unit began to increase after 2015 as screen sizes got bigger and TV technology changed.
6. Since the beginning of F2015, there has been a decline in the proportion of new TVs sold that are Energy Star certified, from over 80 per cent to less than 50 per cent.
7. Retailers and regulators interviewed noted that energy efficiency of TVs is more complicated to measure because of new technologies, additional functionality and increase in screen size, and the tests need to be revised.
8. Compliance with the TV regulation has been over 90 per cent since the B.C. regulation took effect in 2012. Since 2015, when the on mode power limit was removed from the regulation, compliance has been almost 100 per cent. However, average power draw in on mode has begun to increase. From the start of 2016 to the end of 2018, the percentage of TVs sold with on mode power draw higher than the standard set forth in the previous regulation increased from 5 per cent to 25 per cent.

Gross Savings

9. Gross evaluated savings in the new TV market were 50, 45, 42, and 33 GWh/year, respectively, for each year from F2015 to F2018. In contrast, the reported savings for each year over the same period ranged from 64 GWh/year to 69 GWh/year.
10. The evaluated gross savings were consistently lower than the reported savings, and the gap increased in each year. In F2015 evaluated savings were 22 per cent lower than the reported savings for that year, followed by a gap of 31 per cent in F2016, 39 per cent in F2017 and 48 per cent in F2018. There were two main factors that contributed to the

variance. Reported savings were estimated based on 5.6 hours/day while evaluated savings used 5.0 hours/day based on more recent data. Projected TV sales used for reported savings were consistently higher than actual sales, by 11 per cent to 32 per cent depending on the year. Together, these two factors account for approximately 72 per cent of the variance. The remaining 28 per cent of the variance can be attributed to several recent changes to TV characteristics, in particular the increase in screen size over the four year period and the introduction of slightly less energy efficient technology, both of which appear to have had the greatest impact in F2018.

Recommendations

The following recommendations flow from the findings of this evaluation. Recommendations #1 and #2 are for the BC Hydro Codes and Standards group. Recommendation #3 is for Evaluation.

1. Given the rapid changes in TV technologies and features, review the assumptions and calculation inputs used in the energy savings forecast for the TV market on a regular basis.
2. Explore how standard test methods can be changed to better align with new TV technologies and uses.
3. Consider undertaking survey and/or residential monitoring or metering studies to examine and better understand current TV-usage behaviours and hours of use among BC Hydro customers.

4.5 Conclusions

The new TV market continues to change rapidly and new technologies are resulting in homes using larger screen sizes that provide high quality picture and additional features that are important to consumers. Energy efficiency has begun to decline in the on power mode, but efficiency in the off and standby power modes remains high. The changes in the TV market resulted in evaluated savings being lower than reported savings in the F2015 to F2018 period.

Glossary

Baseline: A baseline is the initial condition occurring when a DSM activity begins. It may be a market share for equipment, a current standard, or a current average behaviour.

Cross Effects: Cross effects (also known as interactive effects) refer to the effect that some energy conservation measures (**ECMs**) have on other electricity end uses beyond what the ECM itself produces. An obvious example is building lighting. As more efficient lighting is installed, less heat is generated by the lighting system. This means that less heat must be removed from the building by the air conditioning system during the cooling season, but more heat needs to be supplied by the heating system during the heating season.

Demand Side Management (DSM): The definition of Demand Side Management is the same as the definition of "demand-side measures" set out in section 1 of the *Clean Energy Act*, which is "a rate, measure, action or program undertaken; (a) to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand, but does not include (d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or (e) any rate, measure, action or program prescribed".

End Use: The final application or final use to which energy is applied. Recognition of the fact that electric energy is of no value to a user without first being transformed by a piece of equipment into a service of economic value. For example, office lighting is an end use, whereas electricity sold to the office tenant is of no value without the equipment (light fixtures, wiring, etc.) needed to convert the electricity into visible light. End use is often used interchangeably with energy service.

ENERGY STAR®: ENERGY STAR® is the mark of high-efficiency products in Canada that meet strict technical specifications for energy performance—tested and certified. These products save energy without compromising performance in any way. Typically, an ENERGY STAR® certified product is in the top 15 to 30 per cent of its class for energy performance.

Expected Savings: Estimate of gross energy savings based on customer initially reported savings, engineering review and site inspection. These estimates represent the unverified savings.

Free Riders: Free riders are program participants who would have taken the DSM action, even in the absence of the DSM program. They are a part of the reference case. These actions are not attributable to the program.

Gigawatt Hour (GWh): One billion watt-hours; one million kilowatt hours.

Gross Savings: The change in energy consumption and/or associated demand that results directly from program-related action taken by the participants in the demand side management program irrespective of why they participated.

Market Transformation: Market Transformation refers to a permanent change in the structure or functioning of markets, including more energy-efficient behaviour among customers and higher market penetration of energy-efficient products, as a result of DSM programs that reduce barriers to energy efficiency. These market changes are likely to persist in the absence of continued program activity.

Net savings: The change in energy consumption and/or associated demand that is attributable to the utility DSM program. The change in consumption or associated demand may include the effects of free riders and spillover.

Net-to-gross ratio: A factor representing net demand side management program savings divided by gross program savings that is applied to gross program impacts to convert them into net program load impacts. The factor is made up of a variety of factors that create differences between gross and net savings, commonly including free riders and spillover. Other adjustments may include rebound, cross effects and M&V results.

Peak Demand - Demand refers to the amount of electricity that is consumed at any instant in time, measured in multiples of watts. Peak demand savings are the reduction in amount of electricity that is consumed at system peak demand, which for BC Hydro occurs on a winter weekday between approximately 5 p.m. and 7 p.m.

Persistence: Refers to how long the energy savings are expected to be attributable to the demand side management activity.

Realization Rate: The ratio of initial estimates of savings to savings adjusted for data errors and M&V results. Does not reflect program attribution or influence on the savings achieved.

Reported Savings: Estimate of energy savings being recorded in the program tracking database. Reported savings are based on best information available from technical review of the initial engineering estimate, post implementation review of documentation and/or inspection, or M&V results, as well as, a forecast net-to-gross ratio applied.

Spillover: Refers to program participants and non-participants whose energy savings measures occur through actions that are not part of a program, but which were influenced by the program (also called free drivers or tag-ons). Participant spillover is the additional energy savings that occur when a program participant independently installs energy efficiency measures or applies energy savings practices after having participated in the efficiency program, as a result of the program's influence. Non-participant spillover refers to energy savings that occur when a program non-participant installs energy efficiency measures or applies energy savings practices as a result of a program's influence. Spillover is expressed as a fraction of the increase of energy savings due to spillover to the gross energy savings of the program participant. Spillover may not be permanent and may not continue in the absence of continued program activity.

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix AA

Attachment 3

Demand Side Management Milestone Evaluation Summary Report F2020

Fred James
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

January 22, 2021

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

**RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
2004/05 and 2005/06 Revenue Requirements Application
BCUC Decision: Order No. G-96-04, October 29, 2004,
Directive 66 (page 197)**

In compliance with Directive 66 of the BCUC Decision on BC Hydro's 2004/05 to 2005/06 Revenue Requirements Application, dated October 29, 2004, BC Hydro writes to submit its F2020 Demand Side Management Milestone Evaluation Summary Report dated December 2020.

Directive 66 directs BC Hydro to file the executive summaries of its milestone evaluation reports and full final evaluation reports for all its DSM programs.

The F2020 Demand Side Management Milestone Evaluation Summary Report summarizes the impact evaluations completed during F2020 for the following:

1. Commercial New Construction Program: F2012-F2016 (Final Full Evaluation Report is included in Attachment 1);
2. Leaders in Energy Management Industrial Transmission Program: F2015-F2017; and
3. Load Displacement Initiatives Impact Evaluation: F2021-F2018 (Final Full Evaluation Report included in Attachment 2).

For further information, please contact Chris Sandve at 604-974-4641 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

ls/ma

Enclosure

BC Hydro
Power smart

Demand Side Management Milestone Evaluation
Summary Report F2020

December 2020

This page left blank

Table of Contents

1.0 Introduction

This report summarizes the milestone evaluations of demand-side management (**DSM**) initiatives completed by BC Hydro in fiscal year 2020 (**F2020**). It is filed in compliance with Directive 66 of the British Columbia Utilities Commission (**BCUC**) decision on BC Hydro's F05/F06 Revenue Requirements Application (dated October 29, 2004), which "*directs BC Hydro to file the executive summaries of its milestone evaluation reports and full final evaluation reports of all its Power Smart programs*" (page 197).

BC Hydro evaluates its DSM initiatives to improve its estimates of realized DSM electricity savings and to improve their effectiveness and efficiency.

DSM evaluation activities are guided by the following six principles:

- Objectivity and Neutrality: Evaluations are to be objective and neutral.
- Professional Standards: Evaluation work is guided by industry standards and protocols.
- Qualified Practitioners: BC Hydro employs qualified staff and consultants to conduct evaluations.
- Appropriate Coverage: BC Hydro strives to achieve defined coverage levels for its evaluation of DSM initiatives.
- Business Integration: The evaluation function is integrated into BC Hydro's DSM business process of planning, implementation, reporting and evaluation.
- Coordination: BC Hydro evaluation work is coordinated with FortisBC and other DSM partners where feasible.

BC Hydro DSM evaluations are subject to an independent oversight process to ensure that they are neutral and unbiased, of sufficient quality for their intended purposes, and consistent with industry standards and protocols.

1.1 Completed Evaluations

Impact evaluations summarized in this report include the following:

- Commercial New Construction Program: F2012-F2016
- Leaders in Energy Management Industrial Transmission Program: F2015-F2017
- Power Smart Partners – Load Displacement Initiatives Impact Evaluation: F2012-F2018

2.0 Commercial New Construction Program: F2012-F2016

2.1 Introduction

This report presents an impact evaluation of the BC Hydro Commercial New Construction (**CNC**) program for BC Hydro fiscal years 2012 to 2016 (April 2011 to March 2016). The CNC program was targeted at developers and the building design community who play a role in building and expanding commercial buildings in BC Hydro's service territory. Market actors included developers, building owners, architects, engineers, energy modellers and consultants.

The program's key objective is to obtain electricity energy savings by supporting the design and implementation of cost-effective energy conservation measures beyond applicable building code requirements. There are associated capacity savings (MW) with this program that are derived from the energy savings resulting from the program's energy-focused DSM activities. These savings are not a result of capacity-focused DSM. The CNC program provides direct savings for BC Hydro by supporting the following:

- Energy Efficient Design: identify energy savings by promoting and funding the design of energy efficient buildings (i.e., more energy efficient than the minimum building code legislation requires);
- Energy Efficient Construction: acquire energy savings by promoting and funding the construction of energy efficient buildings and offer training and education on the efficient operation of new buildings; and
- Training and Recognition: enable transformation of the market by training a team of industry professionals to act as energy conservation "ambassadors" (i.e., advocates) on all new construction projects that they work on in the future. In addition, to publicly recognize energy efficient design teams and projects and create a market where consumers highly desire energy efficient buildings.

The program had four offerings:

1. Whole Building Design
    - Targeted at buildings over 50,000 square feet
    - Energy Modelling/Computer simulation of the whole building energy use
2. System Design
    - Targeted at improving the energy efficiency of selected building systems in buildings typically over 50,000 square feet
    - Energy use analysis of a specific system (e.g., lighting, refrigeration, HVAC)
3. Energy Efficient Lighting Design
    - Targeted at buildings typically over 10,000 square feet; and
    - Energy use analysis for lighting - reduction of light power density requirement from building code through design and controls

4. Program Enabled
   - Projects in which the customer engaged with BC Hydro, undertook a funded Energy Study and through this engagement the building design/equipment was influenced leading to energy savings
   - These measures did not receive a program incentive due to not meeting BC Hydro cost effectiveness ratios or due to failing to comply with program incentive offer timing and process

The CNC program is winding down, with all remaining applications scheduled to be completed in F2022. BC Hydro will continue to support the transformation of the commercial new construction market through codes and standards activities that support the B.C. Energy Step Code.

2.2 Approach

The evaluation objectives and research questions are shown below in Table 2.1, followed by the data sources and methods (Table 2.2).

Table 2.1. Evaluation Objectives and Research Questions

Evaluation Objective	Research Questions
1. Assess the participant experience	• What is the level of participant awareness of the various CNC program components? • How do participants rate their program experience and overall satisfaction? • How influential is the CNC program on participant decisions around energy efficiency?
2. Assess practices and opinions related to market transformation	• What are the most common types of design studies being conducted in view of helping to make new construction projects perform better than code? (e.g., whole building energy modelling, a refrigeration system design study, and/or a lighting design study) • What are the most common measures being implemented to help make new construction projects perform better than code? • To what extent do market actors believe the commercial new construction market in the province has improved over the last 10-15 years? • How much electricity do market actors believe new construction projects are saving relative to the energy efficiency requirements in the B.C. Building Code?
3. Assess the influence of the program on the adoption of energy efficiency measures beyond building code requirements	• To what extent has the CNC program developed support for design and construction of more energy efficient buildings (beyond code requirements) among commercial new construction market actors (designers, builders, mechanical engineers, architects etc.)? • To what extent and through which activities is the CNC program influencing building design practices and the new construction market beyond incented projects?
4. Estimate gross energy and peak demand savings	• What are the gross and peak demand savings?
5. Estimate net energy and peak demand savings	• What are the net energy and peak demand savings for the overall CNC program? • What are the free ridership, participant spillover and non-participant spillover rates?

The data sources and analytical methods used to address the objectives are summarized in Table 2.2, followed by a description for each objective.

Table 2.2. Evaluation Objectives, Data and Methods

Evaluation Objective	Data	Methods
1. Assess the participant experience	• Participant Survey (n=57)	• Cross tabulations
2. Assess practices and opinions related to market transformation	• Market Actor Survey (n=13-30)	• Cross tabulations
3. Assess the influence of the program on the adoption of energy efficiency measures beyond building code requirements	• Market Actor Survey (n=13-30)	• Cross tabulations
4. Estimate gross energy and peak demand savings	• Program tracking data • Measurement and verification (n=12)	• International Performance Measurement and Verification Protocol (IPMVP) Option A, B and D • Ratio estimation • Peak demand savings based on peak-to-energy factor
5. Estimate net energy and peak demand savings	• Statistics Canada data on commercial new construction activity, F2012-F2016 • Participating building area (square metres) • Conservation Potential Review (**CPR**) Energy Use Intensity (**EUI**) inputs • Results from Objective 4 • Participant survey (n=51) • Market actor survey (n=13-30)	• Survey based free ridership and participant spillover algorithms • Market Actor Survey based non-participant spillover algorithm

2.3 Results

The results of the evaluation are presented by each evaluation objective, below.

Results for Objective 1: Assess the participant experience

Among program participants, 79 per cent reported being aware of the CNC program offer by name. Of the individual program components, awareness, understanding and rating score was highest for the role that key account managers play as liaisons between the CNC program and participants.

Overall satisfaction was high for the CNC program at 80 per cent, comprised of 41 per cent stating they were very satisfied and 39 per cent stating they were somewhat satisfied. When asked the likelihood of recommending the program to others, 95 per cent indicated that they definitely (53 per cent) or probably (42 per cent) would, and 49 per cent reported that they had in fact already done so.

A total of 80 per cent of participants indicated that the CNC program was very (33 per cent) or somewhat (47 per cent) influential on the decision to implement the energy efficient measures at their site. Looking more broadly at conservation motivators, 60 per cent of participants indicated that the CNC program was a 'major factor' in the organization's effort to manage electricity use over the past year. In terms of barriers to managing electricity use, lack of funds for energy efficient retrofits/projects was noted as a 'major barrier' by 33 per cent of participants, followed by other operational priorities (29 per cent) and lack of financial incentives for conservation programs and energy efficiency (26 per cent).

Results for Objective 2: Assess practices and opinions related to market transformation

With regards to buildings that did not participate in the CNC program, but that market actors reported were performing better than the energy efficiency requirements of the B.C. Building Code, the most common type of design study conducted to help these buildings perform better than code was whole building design. On average, approximately two-thirds of respondents confirmed that at least some floor area of their 'better than code, non-participating projects' had come through this study type. This was followed by lighting design studies, with about 44 per cent of respondents, on average, confirming at least some floor area had come through this study type.

Again, with regards to buildings that did not participate in the CNC program but that were performing better than code, by far the most common measure being implemented to help make these buildings perform better than code was highly efficient lighting, with 83 per cent of respondents reporting that the measure was at least sometimes implemented in their 'better than code, non-participating projects. This was followed by HVAC measures at 64 per cent.

Market actors, including electrical engineers, mechanical engineers, energy modellers, architects and project managers, were asked how much they thought energy efficiency had improved in the entire commercial new construction market in B.C. over the past 10 to 15 years. All respondents thought that there had been some improvement over the past 10 to 15 years – although not necessarily beyond code – with the majority (55 per cent) reporting a 20 per cent improvement. Additionally, all thought that both their own buildings and those constructed by other firms were performing better than code specifically in regards to electricity savings. Savings were reported in the 1 per cent to 30 per cent range, with about half of respondents perceiving that their own buildings had 20 per cent to 30 per cent electricity savings relative to code, compared to only about one-third feeling the same way about buildings constructed by others.

Results for Objective 3: Assess the influence of the program on the adoption of energy efficiency measures beyond building code requirements

A total of 91 per cent of respondents had experience with at least one of the energy efficiency resources or touchpoints provided by the program. The most common were "discussions about projects with BC Hydro staff" (70 per cent) and "reviewing case studies/resource literature" (64 per cent). This was followed by 60 per cent who had "attended a program workshop or training session" and 40 per cent who had "reviewed the Building Envelope Thermal Guide". The least used resource was the "Enhanced Thermal Performance Spreadsheet", with only 21 per cent of respondents indicating they had reviewed it.

Market actors were asked to consider all of their various touchpoints with the program and the influence that these had on their design decisions to have non-participating projects perform better than the building code. A total of 60 per cent indicated that these program touchpoints were 'very' or 'somewhat' influential on their decisions to do so.

In order to understand program influence relative to other factors in the broader new construction context, market actors were asked to credit various factors for making non-program projects perform better than the B.C. Building Code, such that the factors summed to 100 per cent. On average, BC Hydro 'drivers' were given a net of 24 per cent of the credit for making projects perform better than code. It follows that non-BC Hydro drivers were given 76 per cent of the credit for buildings performing better than code.

Another approach to assessing program influence was to query market actors on how much of the improvement in the energy use over time – although not necessarily beyond code – could be attributed to BC Hydro's CNC program. About half (49 per cent) felt it was in the 20 to 30 per cent range, with the most common answer at 20 per cent.

Results for Objective 4: Estimate gross energy and peak demand savings

The evaluated gross savings in fiscal year covered by the evaluation period are presented in Table 23. Evaluated gross electricity savings ranged from 9.2 GWh/year to 24.2 GWh/year from F2012 to F2016, with the most savings occurring in F2014 and the least occurring in F2012.

Table 2.3. Summary of Evaluated Gross and Net Energy and Peak Demand Savings

Year	Evaluated Gross Energy Savings (GWh/year)	Evaluated Gross Peak Demand Savings (MW)	Calculated Net-to-Gross Ratio	Evaluated Net Energy Savings (GWh/year)	Evaluated Net Peak Demand Savings (MW)
F2012	9.2	1.3	0.91	8.4	1.2
F2013	19.9	2.8	0.96	19.2	2.8
F2014	24.4	3.5	0.93	22.7	3.2
F2015	18.8	2.7	0.95	17.9	2.6
F2016	20.6	3.0	0.99	20.4	2.9
CNC (F12-F16)	**92.9**	**13.3**	**0.95**	**88.6**	**12.7**

Results for Objective 5: Estimate net energy and peak demand savings

The evaluated net savings in fiscal year covered by the evaluation period are presented in Table 2.4. Evaluated net electricity savings ranged from 8.4 GWh/year to 22.7 GWh/year from F2012 to F2016, with the most savings occurring in F2014 and the least occurring in F2012.

Table 2.4. Summary of Net Energy and Peak Demand Savings

	Net Energy Savings (GWh/year)		Net Peak Demand Savings (MW)	
Fiscal Year	**Reported**	**Evaluated**	**Reported**	**Evaluated**
F2012	8.1	8.4	1.1	1.2
F2013	15.3	19.2	2.2	2.8
F2014	20.7	22.7	3.0	3.2
F2015	14.0	17.9	2.0	2.6
F2016	15.3	20.4	2.2	2.9
CNC (F12-F16)	**73.4**	**88.6**	**10.5**	**12.7**

The cumulative variance between the reported net energy savings and evaluated energy savings was 15.2 GWh/year. The largest variance occurred in F2016 with a difference of 5.1 GWh between reported and evaluated savings.

Overall, the program achieved 121 per cent of reported savings during fiscal years F2012 to F2016, showing the program performed better than reported. The variance between reported and evaluated net savings is primarily due to the impact of non-participant spillover which was estimated in the evaluation.

2.4 Findings and Recommendations

Findings

Participant Experience

1. Overall satisfaction was high for the CNC program at 80 per cent, comprised of 41 per cent stating they were very satisfied and 39 per cent stating they were somewhat satisfied.

2. The highest scores related to aspects of service/communications from BC Hydro, as well as service provided by contractors. Mid-range scores typically related to aspects of the program offer (variety of products and level of incentives) and the overall application procedures. The lowest scores were for length of time to receive the incentive, length of time for the project/process to be completed and direct mail/email about the program (which was not relied on heavily by this program).

3. Participants reported that the program had been influential on their decision to implement the energy-efficient measures, with 33 per cent indicating that it had been very influential and 47 per cent indicating it had been somewhat influential.

Market Transformation

4. All market actors thought that there had been some improvement in the entire commercial new construction market in B.C. over the past 10 to 15 years – although not necessarily beyond code – with the majority reporting a 20 per cent improvement in terms of energy use over time.

5. The most common types of design study conducted to help new construction projects perform better than code were whole building design and lighting design. The most common measures implemented to help projects perform better than code were lighting and HVAC.

Influence on Adoption of Energy Efficiency Measures Beyond Building Code Requirements

6. On average, BC Hydro 'drivers' were given a net of 24 per cent of the credit for making projects perform better than code, with the largest credit given to previous learnings and experience with the CNC program. The remaining 76 per cent of credit was given to non-BC Hydro drivers, with the largest given to general industry innovation/good practices and to clients directing the projects to be built as such.

Gross Electrical Energy Savings

7. The evaluated gross energy savings were 93 GWh/year.

8. The program gross realization rate calculated using the inspected and verified results, including cross effects, was 1.06, indicating that the energy conservation measures largely performed better than expected. The realization rates by program offer were 1.17, 1.04, 0.89 and 0.89 for whole building design, system design, lighting design and program enabled projects, respectively.

9. Expected energy savings averaged 18 per cent of site energy consumption across all participants during the five-year evaluation period.

Net Electrical Energy Savings

10. The evaluated net energy savings were 89 GWh/year.

11. The net-to-gross ratio was 95 per cent based on free ridership of 20 per cent, participant spillover of 1 per cent and non-participant spillover of 14 per cent.

12. Evaluated net savings during the evaluation period from F2012 to F2016 averaged 121 per cent of reported savings.

Recommendations

The following two recommendations are for future new construction initiatives:

1. Support and enabling activities for whole building energy modelling and integrated system approach to estimate a project's energy savings should continue and include the Building Envelope Thermal Bridging Guide and the Enhanced Thermal Performance Spreadsheet.

2. Future Market Actor surveys could be done more frequently so that respondents are better able to recall the projects they are being surveyed about.

2.5 Conclusions

BC Hydro's Commercial New Construction Program achieved high participant satisfaction. Evaluated net savings were 89 GWh/year, which is 121 per cent of reported savings. Evidence suggests that the program has supported the market in complying with and exceeding the energy efficiency requirements of the B.C. Building Code.

3.0 Leaders in Energy Management Industrial Transmission Program: F2015-F2017

3.1 Introduction

This report presents the results of an impact evaluation of the BC Hydro Leaders in Energy Management – Industrial Transmission (**LEM-T**) program for fiscal years F2015 to F2017 (April 2014 to March 2017).

The LEM-T program captures energy savings at large industrial facilities through energy efficiency retrofits, operational and maintenance changes, and behavioural changes. LEM-T program participants are large industrial customers receiving service at transmission voltages (> 60 kV) who belong to a variety of sectors, including pulp and paper, wood products, mining, oil and gas, chemical, cement and manufacturing.

The LEM-T program was built on a foundation of strategic energy management by providing training, energy managers, energy studies, audits, and other resources to enable large industrial customers to implement facility changes and benefit from the Transmission Service Rate (**TSR**) or leverage capital incentives. The main program components covered by this evaluation are described below.

- **Strategic Energy Management**: LEM-T provides funding to industrial transmission customers for a specially trained Industrial Energy Manager to embed strategic energy management (**SEM**) practices into their organizations. The energy managers conduct energy assessments to help customers gain energy insights, build executive support for energy efficiency and define the energy opportunity and value proposition for their company. They also have access to additional funding and resources to implement employee awareness initiatives and enhanced energy monitoring and targeting systems. In F2017, additional deemed savings for selected SEM participants were claimed for the first time. Prior to that, the program promoted and supported the implementation of SEM activities as a program influence factor but no additional savings were claimed for them.
- **Energy Studies**: LEM-T offers funding to identify energy-saving opportunities through plant-wide audits and end use assessments and to quantify opportunities and build the business case for implementing energy improvement projects through feasibility studies.
- **Custom Project Incentives:** Custom project incentives are financial incentives provided to large industrial customers to implement energy efficiency projects. These projects typically involved "hard-wired" changes to electrical equipment.
- **Self-serve Incentive Program (SIP):** The self-serve incentive component of LEM-T is designed to allow large industrial customers to apply for incentives for improvements to compressed air and lighting systems. The online application makes it quick and easy to apply.
- **Program Enabled (PE) Projects:** Program enabled projects are custom projects that did not receive direct capital incentive funding from BC Hydro, but were enabled by other BC Hydro resources and supports, such as energy managers and energy studies. Customers can claim savings from these projects by providing the appropriate documentation and project details.
- **New Plant Design:** The New Plant Design initiative offers industry expertise to provide an energy base line and energy-efficiency design support for new or expanding facilities. These projects are combined with custom project incentives or program enabled projects to encourage efficient designs that surpass industry standards.

3.2 Approach

The evaluation objectives and research questions are shown in the table below, followed by another table summarizing the data sources and methods for each objective.

Table 3.1. Evaluation Objectives and Research Questions

Evaluation Objectives	Research Questions
1. Examine participant and non-participant experience with the program	What was participant and non-participant awareness and understanding of the various program offers? What was participant satisfaction with the various program offers?
2. Assess outcomes influenced by SEM activities among BC Hydro's large industrial customers	What have been the trends and outcomes associated with strategic energy management over time (e.g., changes in sustainability management, capability, commitment, expectations, application of knowledge)? Were energy managers associated with increased project activities? What was the coverage of energy savings of facilities with energy managers compared to those without? To what extent did SEM lead to additional savings beyond project-based activities? Were the savings achieved in the form of a reduction in energy consumption or reduced energy use intensity? What have been the main barriers to and drivers of adopting and integrating strategic energy management into industrial organizations?
3. Evaluate deemed energy savings of SEM participants	What were the gross energy and peak demand savings from SEM participants with deemed savings? What were the net energy and peak demand savings from SEM participants with deemed savings?
4. Estimate gross electrical energy and peak demand savings due to the incentive offers and program enabled projects (excluding deemed savings of SEM participants)	What were the most common energy conservation measures by end use and customer site type among custom and prescriptive incentive projects, and program enabled projects? What were the evaluated gross energy and peak demand savings realized by custom and prescriptive incentive projects, and program enabled projects?
5. Estimate net electrical energy and peak demand savings due to the incentive offers and program enabled projects (including deemed savings of SEM participants)	How much free ridership occurred for custom and prescriptive incentive projects, and program enabled projects? How much participant and non-participant spillover occurred for the program overall? What were the evaluated net energy and peak demand savings for the combined effect of the LEM-T program and the TSR for custom and prescriptive incentive projects, and program enabled projects?

The following table summarized the data sources and methods used to address each evaluation objective and associated research question.

Table 3.2. Evaluation Objectives, Data and Methods

	Evaluation Objective	Data	Method
1.	Examine participant and non-participant experience with the program	• 2015, 2016, 2017 Participant surveys (n=59) • 2015, 2018 Non-participant survey (n=16)	• Cross tabulations; frequencies
2.	Assess outcomes influenced by SEM activities among BC Hydro's large industrial customers	• Program administrative data • Project files (including energy manager reports, Energy, Monitoring and Targeting (**EMT**) reports, etc.) • Interviews: Energy managers; corporate sponsors / representatives (n=9)	• Cross tabulations; frequencies • Portfolio or sample level modeling • Qualitative analysis
3.	Evaluate deemed energy savings of SEM participants	• Account billing data and TSR records (n=60) • Program administrative data	• Quasi-experimental design comparing SEM participants and non-participants
4.	Estimate gross electrical energy and peak demand savings due to the incentive offers and program enabled projects (excluding deemed savings of SEM participants)	• Project tracking data • Measurement and verification results • Account billing data and TSR records (n=60) • Project files & energy study reports	• Measurement and verification results based on the application of International Performance Measurement and Verification Protocol • File reviews and engineering desk review for projects without Measurement & Verification • Development of realization rates using stratified ratio estimation • Extrapolation of case study findings
5.	Estimate net electrical energy and peak demand savings due to the incentive offers and program enabled projects (including deemed savings of SEM participants)	• Results of Objective 4 • File review and case study results (n=14) • 2015, 2016, 2017 Participant surveys (n=59) • 2015, 2018 Non-participant surveys (n=16)	• Estimation of free ridership by triangulating results of participant surveys and case study reviews • Estimation of spillover for participants and non-participants from survey results and decision tree

3.3 Results

The results of the evaluation are presented by each evaluation objective, below.

Results for Objective 1: Examine participant and non-participant experience with the program

Overall awareness of BC Hydro's conservation programs for industrial customers was high among custom participants at 96 per cent and among SIP participants at 95 per cent. Among non-participants, overall awareness was lower at 75 per cent. In terms of individual program components, awareness, understanding and overall ratings were highest for the role that Key Account Managers play as liaisons for the program, energy studies, and the incentive structures.

Overall satisfaction with the program was very high with 100 per cent of both custom and SIP respondents reporting that they were very or somewhat satisfied. This sentiment was very strong with 71 per cent of custom participants and 78 per cent of SIP participants reporting to be 'very satisfied'. Likewise, 100 per cent of both groups reported that they definitely or probably would recommend the program to others and in fact, 56 per cent of custom participants and 65 per cent of SIP participants reported that they had already done so.

In terms of program experience, 'service provided by BC Hydro personnel' and 'knowing how/who to contact at BC Hydro' were rated very favourably by both custom and SIP participants. Among custom participants, the ‘variety of products funded under the program’ and service provided by both suppliers/distributors and by contractors received strong ratings. Among SIP participants, the ‘level of incentives’ and ‘service provided by suppliers/distributors’ were rated highly. Aspects with the lowest rating scores for custom participants included those related to ‘length of time to receive incentive’ and ‘length of time to receive project approval’ as well as for ‘overall application procedures’. For SIP, the aspects with the lowest scores were ‘length of time to receive project approval’ and ‘length of time for the project to be completed’ as well as ‘clarity of communications from BC Hydro about the project’.

Results for Objective 2: Assess outcomes influenced by SEM activities among BC Hydro’s large industrial customers

Based on the interviews with Energy Managers and corporate sponsors, cost reduction was named as the main driver for adopting and integrating SEM into their respective organizations. Cost was also raised as one of the main barriers in implementing SEM, in addition to competition with other initiatives and overloaded resources.

Since the adoption of SEM, interviewees reported that corporate commitment and expectations regarding energy consumption have resulted in a number of positive developments, including more involvement and buy-in from senior management, more reporting and awareness of energy use, and more discussion about energy management throughout all levels of staff. Additionally, SEM principles were reported to be integrated into capital projects more often and some interviewees felt that there had been cultural shifts in their organizations in terms of conservation-mindedness. Most of the Energy Managers interviewed felt that in the absence of BC Hydro, SEM would not be implemented at their company.

On average, sites with Energy Managers completed over four times the number of projects per site relative to those without energy managers (4.6 projects per site compared to 1). Also, sites with an energy manager completed larger projects and achieved 1.7 times more energy savings per project. Overall, sites with Energy Managers achieved a 3.7 per cent reduction of site energy consumption through capital projects, compared to 0.9 per cent for sites without Energy Managers. Sites with Energy Managers and with active strategic energy management had over 5 per cent energy savings from capital projects implemented between F2015 and F2017.

Results for Objective 3: Evaluate deemed energy savings of SEM participants

Expected savings claimed by the program for this component were based on a deemed value of 2 per cent of site energy consumption for sites that met a pre-qualifying threshold of SEM practices. The average site gross realization was estimated at 0.8 and the net to gross ratio at 0.9. The evaluated net energy savings from strategic energy management in F2017 ranged from a lower estimate of 0.7 per cent of site energy consumption (16 GWh/year) to an upper estimate of 2.0 per cent (43 GWh/year), with an average of 1.4 per cent for 30 GWh per year energy and 3.5 MW of peak demand savings. The following table summarizes the evaluated net SEM energy savings.

Table 3.3. Net Realization Rates and Lower and Upper Estimates of SEM Energy Savings

	Average Estimate	Lower Estimate	Upper Estimate
Expected energy savings (GWh/year)	43.4		
Net realization rate	0.7	0.4	1.0
Per cent savings of site energy consumption in F2017	1.4%	0.7%	2.0%
Evaluated net energy savings (GWh/year)	30	16	43
Peak demand savings (MW)	3.5	1.9	5.0

Results for Objective 4: Estimate gross electrical energy and peak demand savings due to the incentive offers and program enabled projects (excluding deemed savings of SEM participants)

The overall LEM-T program realization rate for the period F2015-F2017 was estimated as the ratio of evaluated to expected gross savings for all measures included in the evaluation analysis, but not including savings from strategic energy management. The gross realization rates of the two incentive program offers ranged from 0.90 to 0.96. The overall realization rate for capital projects was calculated at 94 per cent. This means that, on average, measures in the realization rate sample achieved 94 per cent of their expected savings. The following table provides the expected and evaluated gross energy and peak demand savings by fiscal year for capital projects.

Table 3.4. Expected and Evaluated Gross Energy and Peak Demand Savings from Capital Projects by Fiscal Year

Period	Number of Projects	Number of Measures	Expected Gross Energy Savings (GWh/year)	Calculated Realization Rate	Evaluated Gross Energy Savings (GWh/year)	Evaluated Gross Peak Demand Savings (MW)
F2015	115	175	145.2	0.98	142.2	16.6
F2016	123	197	102.7	0.90	92.6	10.8
F2017	107	142	145.8	0. 92	133.5	15.6
LEM-T (F15-F17)	**345**	**514**	**393.7**	**0.94**	**368.3**	**43.1**

Results for Objective 5: Estimate net electrical energy and peak demand savings due to the incentive offers and program enabled projects (including deemed savings of SEM participants)

Capital Projects

The overall level of free ridership was estimated at 20 per cent for the program, ranging from 5 to 52 per cent between program offers. Participant spillover was estimated at 11 per cent and non-participant spillover was estimated at 2 per cent, for a total estimated spillover effect of 13 per cent.[1] Together they result in a net-to-gross ratio from capital projects of 93 per cent as shown in Table 3.6. Results are summarized in the table below, where free ridership, spillover and the net-to-gross ratio are presented by offer.

[1] Spillover of SEM participants was estimated at zero per cent as it is included in the estimate of energy savings from strategic energy management.

Table 3.5. Free Ridership, Spillover, and Net-to-Gross Ratios by Program Offer

Program Offer	Incentive Custom	Incentive SIP	Program Enabled - Retrofit	Program Enabled - New Plant Design
Evaluated Gross Energy Savings (GWh/year)	94.6	21.9	149.8	101.9
Free Ridership (**FR**)	6%	5%	10%	52%
Spillover (**SO**)	13%	13%	13%	13%
Net-to-Gross Ratio (1 – FR + SO)	**107%**	**108%**	**103%**	**61%**
Evaluated Net Energy Savings (GWh/year)	101.3	23.7	154.3	62.2

Evaluated net energy savings from capital projects in each fiscal year were calculated using the evaluated gross energy savings of each project multiplied by the net-to-gross ratio of its program offer. These results are summarized in the following table.

Table 3.6. Evaluated Gross and Net Energy and Peak Demand Savings from Capital Projects

Year	Evaluated Gross Energy Savings (GWh/year)	Evaluated Gross Peak Demand Savings (MW)	Calculated Net-to-Gross Ratio	Evaluated Net Energy Savings (GWh/year)	Evaluated Net Peak Demand Savings (MW)
F2015	142.2	16.6	0.85	121.4	14.2
F2016	92.6	10.8	0.88	81.1	9.5
F2017	133.5	15.6	1.04	138.9	16.2
LEM-T (F15-F17)	**368.3**	**43.1**	**0.93**	**341.4**	**39.9**

Total Program Reported and Evaluated Net Savings

Reported and evaluated net energy and peak demand savings for LEM-T are shown below. Reported savings included the results of the best available estimate from either M&V, post-implementation review, and expected savings, as well as the deemed savings estimate for strategic energy management, and were adjusted by a forecast net-to-gross ratio of 0.908.

Table 3.7. Summary of Energy and Peak Demand Savings

	Net Energy Savings (GWh/year)		Net Peak Demand Savings (MW)	
Fiscal Year	Reported	Evaluated	Reported	Evaluated
F2015	134.2	121.4	15.7	14.2
F2016	91.3	81.1	10.7	9.5
F2017	163.0	169.4	19.1	19.8
LEM-T (F15-F17)	**388.5**	**371.9**	**45.5**	**43.5**

3.4 Findings and Recommendations

Findings

Below are the main evaluation findings.

Participant and Non-Participant Experience

1. Approximately two-thirds of all industrial transmission sites participated in the LEM-T program during the three-year evaluation period (F2015-F2017). Highest participation came from the pulp and paper, mining and wood products industry sectors.
2. Self-reported awareness and understanding of the various program components was high among participants, with the exception of the New Plant Design offer. Awareness and understanding among non-participants were expectedly lower, particularly for the incentive offers.
3. Overall satisfaction was very high with 100 per cent of both custom and SIP survey respondents reporting that they were very or somewhat satisfied with the program.
4. Among both custom and SIP participants, service provided by BC Hydro personnel and knowing how/who to contact at BC Hydro were the highest rated aspects of customer experience. Among custom participants, the variety of products funded under the program was also rated highly, as was the level of incentives among SIP participants. The lowest rated elements for both program offers were generally related to length of time aspects (length of time to receive project approval, length of time to receive incentive and length of time for the project to be completed).

Outcomes Influenced by Strategic Energy Management (SEM) Activities

5. The main motivator for organizations to participating in SEM was energy cost reduction. Costs were also cited as a main barrier to implementing SEM, in addition to competition with other corporate initiatives and overloaded resources.
6. Companies adopting SEM reported a number of positive developments in energy management, including more involvement and buy-in from senior management, increased reporting and awareness of energy use, SEM principles being integrated into capital projects, and cultural shifts in terms of conservation-mindedness. In the absence of BC Hydro support, most organizations felt that SEM would not have been implemented, resulting in sites having higher energy bills, being less successful at energy management and having less employee engagement around energy use.
7. Energy Managers played an important role in program participation. Energy Managers covered 83 per cent of projects among program participants. On average, sites with Energy Managers completed over four times as many projects than sites without Energy Managers.
8. Overall, from F2015 to F2017, sites with Energy Managers achieved a 3.7 per cent reduction of site energy consumption through capital projects, compared to only 0.9 per cent for sites without Energy Managers. Sites with Energy Managers and with active strategic energy management had the highest per cent reduction in site energy consumption, at over 5.5 per cent, when looking at the combined impact of capital projects and SEM.

Deemed energy savings for SEM participants

9. Evaluated net energy savings from strategic energy management were incremental to energy savings from capital projects and estimated in the range of 0.7 per cent to 2 per cent (average of 1.4 per cent) of energy consumption of participants with one year persistence. Energy savings from strategic energy management were weighted by site energy consumption.

Gross Electrical Energy Savings from Capital Projects

10. The realization rate among gross energy savings was 94 per cent, indicating that the energy conservation measures largely performed as expected. The most common reason why measures did not perform as expected was changes in operating conditions identified during post-implementation review.

11. Evaluated gross energy savings per year averaged 4.3 per cent of site energy consumption across all participants between F2015 and F2017, and capital project savings per site ranged from less than 0.1 per cent to over 16 per cent.

12. By including additional data sources in the evaluation review, such as TSR records and customer post-implementation data, the coverage of the gross realization rate sample was doubled from what it would have been using measurement and verification (**M&V**) results alone. However, the results of evaluation reviews are considered less rigorous than those of M&V analysis conducted in accordance with the IPMVP.

Net Electrical Energy Savings

13. The overall level of free ridership was estimated at 20 per cent for the program, ranging from 5 to 52 per cent between program offers. Participant spillover was estimated at 11 per cent and non-participant spillover was estimated at 2 per cent for a total of 13 per cent. Together they result in a net-to-gross ratio of 93 per cent.
14. Free ridership for program enabled new plant design projects was the highest at 52 per cent because case studies found that four of the six projects considered the existing older technology for the equivalent service alternative, although industry standard practice for new equipment had improved in energy efficiency, and there was potential for substantial non-energy benefits as a business driver.
15. Evaluated net energy savings for LEM-T were 121.4 GWh/year in F2015, 81.1 GWh/year in F2016, and 169.4 in F2017 which averaged 96 per cent of reported savings.
16. The average weighted persistence of all capital measures (i.e., the length of time that the savings are reported by the program) was 11.5 years during the evaluation period. When including savings from SEM participants, the average weighted persistence of all savings reported in LEM-T was 10.6 years.

Recommendations

Recommendations #1 and #2 are for program management:

1. In order to better estimate energy savings and document program influence in program enabled new plant design projects, consider the market baseline option of the process technology and include the relevant energy study or energy savings estimation in the project file prior to equipment purchase and project implementation.
2. In consultation with the evaluation department, consider ways to improve the evaluability of the strategic energy management initiative through documentation of the energy conservation measures leading to SEM savings with initial energy savings estimates.

Recommendations # 3 and #4 are for the evaluation team:

3. Work with the program to improve the evaluability of the strategic energy management initiative by developing standardized methods to monitor the progress of program participants for benchmarking impact of SEM activities and determining SEM energy savings.
4. Continue working with industry associations to explore energy savings methods to include natural conservation, market forces and business drivers, and persistence of SEM savings.

3.5 Conclusions

BC Hydro's Leaders in Energy Management – Transmission program achieved 96 per cent of reported savings during fiscal years F2015 to F2017. The program also achieved high levels of customer awareness and satisfaction. Strategic energy management contributed to significantly higher levels of program activity and additional energy savings among participants.

4.0 Power Smart Partners – Load Displacement Initiatives Impact Evaluation: F2012-F2018

4.1 Introduction

This report presents the results of an impact evaluation covering the eight load displacement projects implemented during the period from F2012 to F2016. Since the program has ended and no new projects were implemented in F2017 and F2018 and operational data was available for all the projects, the evaluation period covers F2012 to F2018.[2] The projects were funded through the Power Smart Partners-Transmission (PSP-T) Integrated Power Offer (IPO) or Load Displacement (LD) program offers and were not included in the scope of any previous impact evaluations.

Load displacement projects are customer-based generation projects that self-supply part of the customer's site electrical load. For these projects, industrial, commercial and institutional customers received BC Hydro funding and program support to generate their own electricity for self-supply and offset their electricity purchases from BC Hydro. All customer-based generation projects over 50 kW were reviewed through the Integrated Customer Solutions (ICS) process. The load displacement project enabling activities were specifically designed to operate under the ICS framework and remove technical and financial barriers specific to self-generation projects. Load displacement projects were treated as having reduced customer energy purchases similar to energy conservation project initiatives for industrial transmission customers.

4.2 Approach

The evaluation objectives and research questions are summarized in the following table.

Table 4.4 Evaluation Objectives and Research Questions

Evaluation Objective	Research Questions
1. Estimate gross electricity generation and peak demand impacts.	What were the evaluated gross electricity generation and demand impacts realized by load displacement projects aggregated by fiscal year and, to the extent possible, disaggregated by relevant factors*?
2. Estimate net electricity generation and peak demand impacts.	What were the relative magnitude of parasitic loads[3] and their energy use as related to the load displacement projects?
	What were the evaluated net electricity generation and demand impacts realized by load displacement projects aggregated by fiscal year and, to the extent possible, disaggregated by relevant factors?
	To what extent did parallel energy procurement initiatives[4] impact the net electricity generation of the load displacement projects?

* Relevant factors may include technology type, primary energy source, seasonal operating mode and operating strategy with other on-site process heat requirements that impact the net electricity generation.

2 The Load Displacement initiative was no longer available after F2017.

3 Parasitic load is the electrical energy that is required for the operation of the load displacement project.

4 Other energy procurement initiatives include electricity purchase agreements, contracted generation baseline loads, and tariff treatments.

The objectives, data sources and methods used for this evaluation are shown in Table 4.2.

Table 4.1. Evaluation Objectives, Data and Method

	Evaluation Objectives	Data	Method
1.	Estimate gross electricity generation and peak demand impacts.	• Project files • Self-generation eMetering • Customer process requirements • Billing records and Customer Baseline Load (CBL) Statements[5]	• Annual measurement and verification results and evaluation review • Self-generation load shapes, capacity factors and peak-to-energy factors • Engineering calculations
2.	Estimate net electricity generation and peak demand impacts.	• Load displacement feasibility studies • Reported savings • Project files	• Engineering estimates of parasitic loads • Annual measurement and verification results and evaluation review

Electricity self-generation impacts were evaluated over the period from F2012 to F2018 based on hourly interval data through annual measurement and verification or annual reconciliation of the site's total generation energy.

Objective 1: Estimate Gross Electricity Generation and Peak Demand Impacts

Evaluated gross electricity generation is the energy generated due to the program and estimated from the annual measurement and verification (M&V) results and billing records by fiscal year. Four of the eight projects underwent an annual measurement and verification process for the estimation of gross and net electricity generation. These four projects with M&V are load displacement projects where a new generator was installed. They are grouped in this evaluation under 'New Power Generation' and M&V results were used as the basis of the gross generation energy for evaluation review. The other four load displacement projects were due to refurbishment and upgrading of existing steam turbo-generators which resulted in incremental generation to already existing generation. These are grouped in this evaluation under 'Rebuilt Turbo Generator'. The annual gross incremental generation energy from the rebuilt units was verified by BC Hydro based on revenue metering data for each fiscal year and provided in the customer's billing records. For these projects, the customer's billing records were used as the basis of the gross generation energy for evaluation review.

The gross peak demand impact by the load displacement projects was estimated using the peak-to-energy factor of the total self-generation system at each site. These were evaluated based on hourly interval data during steady-state operations in winter by dividing the average generation power during peak periods by the load displacement project's annual generation energy.

Objective 2: Estimate Net Electricity Generation and Peak Demand Impacts

The net electricity generation is the difference between the energy delivered by the generator and the parasitic energy requirements. The evaluated parasitic energy was estimated based on recent actual performance as the most likely indicator of future performance of the load displacement project.

The parasitic energy estimate for the four New Power Generation projects with M&V was verified by the M&V group using engineering calculations and spot measurements when available. No M&V results were available for the four Rebuilt Turbo Generator projects and a deemed estimate of the incremental parasitic energy was applied based on the default assumption of 3 per cent of incremental gross generation energy[6] of the load displacement project.

---

[5] CBL Statements are issued annually by BC Hydro for each customer on stepped rate schedule (RS1823B) that includes any adjustment made to a customer's energy bill for the purpose of Customer Baseline Load (CBL) administration.

[6] U.S. Department of Energy (2017). *Uniform Methods Project, Chapter 23: Combined Heat and Power Evaluation Protocol.*

The evaluated net generation peak demand impact of the program was estimated using the same peak-to-energy factors determined for Objective 1, applied to the project-based M&V estimates for parasitic energy and metered load shapes of the generation energy. This assumed that the load shape of the parasitic energy is the same as the load shape of the generation energy.

It was not an objective of this evaluation to attribute changes in generation energy to the load displacement initiatives, which would take into consideration free ridership and spillover. In this evaluation, the term 'net generation impact' refers to the gross generation energy less parasitic energy and does not imply attribution to any intervening initiative. These load displacement projects were assumed to have no free ridership and non-existent spillover, for a net-to-gross ratio of one, for two reasons. First, all self-generation projects had to apply to BC Hydro for generator inter-connection and go through the integrated customer solutions process for review and evaluation. All of the eight load displacement projects in this evaluation were then directed to the load displacement capital incentive offer by BC Hydro and each project had its own business case developed with BC Hydro executive approval of the incentive amount. As a result of this process, BC Hydro does not expect that there was any free ridership with regard to the capital incentive. Second, all generation energy is metered and customers were required to service their self-generation contracts in a prescribed order which was verified by BC Hydro for billing purposes. As a result, any spillover of unreported generation energy is not considered to be possible.

4.3 Results

Results for Objective 1: Estimate Gross Electricity Generation and Peak Demand Impacts

Table 4.3 shows the number of load displacement projects implemented by fiscal year, as well as the cumulative rated capacity, the evaluated gross generation energy, and the evaluated gross peak demand impact. Results are given as cumulative due to the variation of project results with annual review through measurement and verification.

The peak-to-energy factor was evaluated for each project from hourly interval data based on the average power generated between December and February. Peak-to-energy factors are usually determined using winter weekday evening loads, to correspond with the BC Hydro system peak, but the variations of generated power between winter days of the week (weekday versus weekend) and winter hours of the day (evenings versus other hours of the day) were found to be negligible. The average evaluated peak-to-energy factor was found to be 0.126 MW per GWh, almost 8 per cent higher than the industrial transmission rate class average of 0.117 MW per GWh which is typically applied to energy conservation measures. This higher peak-to-energy factor resulted in a higher estimate of peak demand impact for load displacement projects.

A number of other factors were examined to assess the performance of load displacement projects in terms of system availability and capacity utilization. Detailed results discussed in the report indicate that all load displacement projects had excess capacity to potentially increase generation power and energy.

Table 4.3 Evaluated Cumulative Gross Generation Energy and Peak Demand Impact

Fiscal Year	Number of New Projects	Load Displacement Project Type	Cumulative Rated Capacity (MW)	Cumulative Evaluated Gross Generation Energy (GWh/year)	Cumulative Evaluated Gross Peak Demand Impact (MW)
F2012	2	2x Rebuilt Turbo Generator	26	167	21
F2013	1	1x New Power Generation	28	181	23
F2014	0	-	28	181	23
F2015	2	1x Rebuilt Turbo Generator 1x New Power Generation	31	204	25
F2016	3	1x Rebuilt Turbo Generator 2x New Power Generation	41	263	33
F2017	0	-	41	263	33
F2018	0	-	41	263	33

Objective 2: Estimate Net Generation Energy and Peak Demand Impacts

Table 4.4 summarizes key results by project type and shows the evaluated net generation energy after adjustment for parasitic energy.

Table 4.4. Net Generation Results by Project Type

	Group 1 Rebuilt Turbo Generator	Group 2 New Power Generation
Number of Projects	4	4
Rated Capacity (MW)	32.1	8.9
Evaluated Gross Generation Energy	204	59
Evaluated Net Generation Energy (GWh/year)	198	55
Parasitic Energy Factor	3%	6.5%
Peak-to-Energy Factor (MW/GWh)	0.129	0.117
Realization Rate[7]	91%	98%
Load displacement to facility energy ratio[8]	18%	14%
LD energy to total self-generation energy	25%	100%

Table 4.5 shows a summary of reported and evaluated net generation energy and peak demand by fiscal year. Year over year reporting of load displacement generation energy improved as the operation of the systems reached steady-state. However, there was a time lag because measurement and verification results or billing reconciliation for a given reporting year only became available after fiscal year-end and were then used as the best available estimate for the next year. Considering this time lag in reporting of variations in performance between fiscal years, the evaluated net generation energy was estimated on average to have achieved 96 per cent of the reported generation energy. The variance is primarily due to inconsistency in reporting of Rebuilt Turbo Generator projects, using their expected generation energy instead of the actual generation energy, and the lack of accounting of parasitic energy in reported savings for these projects. If the reported generation energy were adjusted for actual generation energy and estimated parasitic energy, the overall variance between reported and evaluated net generation energy of all eight load displacement projects would be reduced to less than one per cent.

---

7 Realization rate is the ratio of evaluated net energy generation to the expected generation energy, which is the contracted generation energy of the incentive agreement.

8 The load displacement to facility energy ratio indicates the proportion of site energy consumption that was displaced by the load displacement project on an annual basis.

9 The load displacement to total self-generation ratio indicates the proportion of total self-generation energy at the site that was contributed by the load displacement project on an annual basis.

Table 4.5. Summary of Net Generation Energy and Peak Demand Impact

Fiscal Year	Net Generation Energy (GWh/year)		Net Peak Demand Impact (MW)	
	Reported	Evaluated	Reported	Evaluated
F2012	254	162	30	20
F2013	254	176	30	22
F2014	195	176	23	22
F2015	215	196	25	25
F2016	271	253	32	32
F2017	260	253	30	32
F2018	262	253	31	32

4.4 Findings and Recommendations

Findings

1. Eight load displacement projects were evaluated for a total of 263 GWh per year in gross generation energy and 253 GWh per year in net generation energy. This resulted in 33 MW of gross peak demand impact and 32 MW of net peak demand impact.
2. Seven of the eight load displacement projects ranged from 1 MW to 5 MW in size and one exceeded 25 MW in rated capacity. Seven of the load displacement projects were considered combined heat and power and used biomass and bioenergy as the primary energy source.
3. The four Rebuilt Turbo Generator projects were found to have average availability, capacity and utilization factors of 94 per cent, 78 per cent and 72 per cent respectively. The other four projects were of the New Power Generation type and were found to have average availability, capacity and utilization factors of 91 per cent, 84 per cent and 76 per cent respectively.
4. The load displacement project realization ranged from 75 per cent to 107 per cent, with a weighted average project realization rate of 91 per cent for Rebuilt Turbo Generator and 98 per cent for New Power Generation type projects. The overall program realization rate was 92 per cent.
5. All projects undergo annual verification of the generation energy using hourly interval data. Rebuilt Turbo Generator load displacement projects had verification of actual gross generation energy recorded by BC Hydro, whereas New Power Generation projects underwent annual measurement and verification activities, recording both gross and net generation energy. The reported generation energy is adjusted yearly based on this annual review for all New Power Generation type projects but not for Rebuilt Turbo Generator type projects.
6. The generation energy provided in the customer's annual CBL Statements was found to be the best available estimate for projects without annual measurement and verification. These generation energy records explain most of the variance between reported and evaluated gross generation energy for Rebuilt Turbo Generator type load displacement projects.
7. The peak-to-energy factor was found to be 8 per cent higher than the industrial rate class average because six of the eight projects generated more power during BC Hydro's system

winter peak as a result of higher availability factors in winter months. Generator shutdowns and annual maintenance periods, which decreased overall availability, were observed to typically occur in the spring and summer months. Two projects had peak-to-energy factor lower than the industrial rate class average because of higher process heat requirements in winter.

8. Parasitic energy is the difference between gross and net generation energy and was evaluated at 3 per cent for Rebuilt Turbo Generator projects and 6.5 per cent for New Power Generation projects. New Power Generation projects have more auxiliary energy requirements than incremental generation projects from Rebuilt Turbo Generators. The parasitic energy explains most of the difference between reported and evaluated net generation energy.
9. The average weighted persistence of load displacement projects was estimated to be 16 years and ranging from 10 years to 20 years. The BC Hydro Persistence Standard indicates 20 years persistence for New Power Generation type projects and 15 years persistence for Rebuilt Turbo Generator projects. Any changes to generation energy and persistence are captured in the annual M&V and engineering review process.
10. The evaluation found evidence of continuous improvement of the utilization factor of three New Power Generation load displacement projects through the annual review and the M&V process. Project underperformance was observed due to restriction in condensing capacity, fuel supply, and electrical metering issues that were identified and corrected during the first three years of operating the load displacement projects.

Recommendations

The following recommendations are for the BC Hydro Load Displacement initiative managers based on the findings of this evaluation.

1. Continue to conduct annual review and measurement and verification of all load displacement projects for reporting of actual net generation energy per fiscal year.
2. The program should use the generation energy from customer's annual CBL Statements as the best available estimate when annual measurement and verification results are not available. These apply to Rebuilt Turbo Generator type projects at large industrial customer sites with transmission service that are on the stepped rate (RS 1823B).
3. The program should apply a 3 per cent reduction to the gross generation energy for projects without an engineering estimate of parasitic energy, i.e., load displacement projects of Rebuilt Turbo Generator type.

4.5 Conclusions

BC Hydro's load displacement initiatives achieved 92 per cent of expected generation energy during fiscal years F2012 to F2018. The New Power Generation projects achieved 98 per cent due to continuous improvement of project performance, whereas the Rebuilt Turbo Generator projects achieved 91 per cent due to overestimated utilization factor and underestimated parasitic energy. The evaluated net generation energy of both types of load displacement projects was found to produce an equivalent reduction in site energy purchases.

5.0 Glossary

ANCOVA: is a general linear model which blends analysis of variance (**ANOVA**) and regression to test the main and interaction effects of categorical variables on a continuous dependant variable, controlling for the effects of selected other continuous variables, which co-vary with the dependant.

Baseline: A baseline is the initial condition occurring when a DSM activity begins. It may be a market share for equipment, a current standard, or a current average behaviour.

Cross Effects: Cross effects (also known as interactive effects) refer to the effect that some energy conservation measures (**ECMs**) have on other electricity end uses beyond what the ECM itself produces. An obvious example is building lighting. As more efficient lighting is installed, less heat is generated by the lighting system. This means that less heat must be removed from the building by the air conditioning system during the cooling season, but more heat needs to be supplied by the heating system during the heating season.

Demand Side Management (DSM): The definition of Demand Side Management is the same as the definition of "demand-side measures" set out in section 1 of the Clean Energy Act, which is "a rate, measure, action or program undertaken; (a) to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand, but does not include (d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or (e) any rate, measure, action or program prescribed".

End Use: The final application or final use to which energy is applied. Recognition of the fact that electric energy is of no value to a user without first being transformed by a piece of equipment into a service of economic value. For example, office lighting is an end use, whereas electricity sold to the office tenant is of no value without the equipment (light fixtures, wiring, etc.) needed to convert the electricity into visible light. End use is often used interchangeably with energy service.

Expected Savings: Estimate of gross energy savings based on customer initially reported savings, engineering review and site inspection. These estimates represent the unverified savings.

Evaluated Savings: Savings estimates reported after the energy efficiency activities have been implemented and an impact evaluation has been completed.

Free Riders: Free riders are program participants who would have taken the demand-side management (**DSM**) action, even in the absence of the DSM program. They are a part of the reference case. These actions are not attributable to the program.

Gigawatt Hour (GWh): One billion watt-hours; one million kilowatt hours.

Gross Savings: The change in energy consumption and/or associated demand that results directly from program-related action taken by the participants in the demand side management program irrespective of why they participated.

Market Transformation: Market Transformation refers to a permanent change in the structure or functioning of markets, including more energy-efficient behaviour among customers and higher market penetration of energy-efficient products, as a result of demand-side management (**DSM**) programs that reduce barriers to energy efficiency. These market changes are likely to persist in the absence of continued program activity.

Net savings: The change in energy consumption and/or associated demand that is attributable to the utility DSM program. The change in consumption or associated demand may include the effects of free riders and spillover.

Net-to-gross ratio: A factor representing net demand side management program savings divided by gross program savings that is applied to gross program impacts to convert them into net program load impacts. The factor is made up of a variety of factors that create differences between gross and net savings, commonly including free riders and spillover. Other adjustments may include rebound, cross effects and M&V results.

Peak Demand: Demand refers to the amount of electricity that is consumed at any instant in time, measured in multiples of watts. Peak demand savings are the reduction in amount of electricity that is consumed at system peak demand, which for BC Hydro occurs on a winter weekday between approximately 5 p.m. and 7 p.m.

Persistence: Refers to how long the energy savings are expected to be attributable to the demand side management activity.

Quasi-experiment: In a quasi-experimental design, there is no random assignment, but treatment and comparison group members are matched on some relevant characteristic(s) and selected on a probabilistic basis.

Realization Rate: The ratio of initial estimates of savings to savings adjusted for data errors and M&V results. Does not reflect program attribution or influence on the savings achieved.

Reported Savings: Estimate of energy savings being recorded in the program tracking database. Reported savings are based on best information available from technical review of the initial engineering estimate, post implementation review of documentation and/or inspection, or M&V results, as well as, a forecast net-to-gross ratio applied.

Spillover: Refers to program participants and non-participants whose energy savings measures occur through actions that are not part of a program, but which were influenced by the program (also called free drivers or tag-ons). Participant spillover is the additional energy savings that occur when a program participant independently installs energy efficiency measures or applies energy savings practices after having participated in the efficiency program, as a result of the program’s influence. Non-participant spillover refers to energy savings that occur when a program non-participant installs energy efficiency measures or applies energy savings practices as a result of a program’s influence. Spillover is expressed as a fraction of the increase of energy savings due to spillover to the gross energy savings of the program participant. Spillover may not be permanent and may not continue in the absence of continued program activity.

Impact Evaluation of the Commercial New Construction (CNC) Program: F2012-F2016

January 23, 2020

Prepared by:

BC Hydro Conservation and Energy Management Evaluation

This page left blank

TABLE OF CONTENTS

This page left blank

Executive Summary

Introduction

This report presents an impact evaluation of the BC Hydro Commercial New Construction program for BC Hydro fiscal years F2012 to F2016 (April 2011 to March 2016). The CNC Program was targeted at developers and the building design community who play a role in building and expanding commercial buildings in BC Hydro's service territory. Market actors included developers, building owners, architects, engineers, energy modellers and consultants.

The program's key objective is to obtain electricity energy savings by supporting the design and implementation of cost effective energy conservation measures beyond applicable building code requirements. There are associated capacity savings (MW) with this program that are derived from the energy savings resulting from the program's energy-focused DSM activities, not a result of capacity-focused DSM. The CNC Program provides direct savings for BC Hydro by supporting the following:

- Energy Efficient Design: identify energy savings by promoting and funding the design of energy efficient buildings (i.e., more energy efficient than the minimum building code legislation requires);
- Energy Efficient Construction: acquire energy savings by promoting and funding the construction of energy efficient buildings and offer training and education on the efficient operation of new buildings; and
- Training and Recognition: enable transformation of the market by training a team of industry professionals to act as energy conservation "ambassadors" (i.e., advocates) on all new construction projects that they work on in the future. In addition, to publicly recognize energy efficient design teams and projects and create a market where consumers highly desire energy efficient buildings.

The program had 4 offerings:

1. Whole Building Design: targeted at buildings over 50,000 square feet;
    a. Energy Modelling/Computer simulation of the whole building energy use
2. System Design: targeted at improving the energy efficiency of selected building systems in buildings typically over 50,000 square feet;
    b. Energy use analysis of a specific system (e.g., lighting, refrigeration, HVAC)
3. Energy Efficient Lighting Design: targeted at buildings typically over 10,000 square feet; and
    c. Energy use analysis for lighting. Reduction of light power density requirement from building code through design and controls
4. Program Enabled.
    d. Projects in which the customer engaged with BC Hydro, undertook a funded Energy Study and through this engagement the building design/equipment was influenced leading to energy savings. These measures did not receive a program incentive due to not meeting BC Hydro cost effectiveness ratios or due to failing to comply with program incentive offer timing and process.

The Commercial New Construction program is winding down, with all remaining applications scheduled to be completed in F2022. BC Hydro will continue to support the transformation of the commercial new construction market through codes and standards activities that support the B.C. Energy Step Code.

Approach

The evaluation addressed five objectives each with related research questions, as presented in Table ES. 1.

Table ES.1. Evaluation Objectives and Research Questions

Evaluation Objective	Research Questions
1. Assess the participant experience	• What is the level of participant awareness of the various CNC program components? • How do participants rate their program experience and overall satisfaction? • How influential is the CNC program on participant decisions around energy efficiency?
2. Assess practices and opinions related to market transformation	• What are the most common types of design studies being conducted in view of helping to make new construction projects perform better than code? (e.g., whole building energy modelling, a refrigeration system design study, and/or a lighting design study) • What are the most common measures being implemented to help make new construction projects perform better than code? • To what extent do market actors believe the commercial new construction market in the province has improved over the last 10-15 years? • How much electricity do market actors believe new construction projects are saving relative to the energy efficiency requirements in the B.C. Building Code?
3. Assess the influence of the program on the adoption of energy efficiency measures beyond building code requirements	• To what extent has the CNC program developed support for design and construction of more energy efficient buildings (beyond code requirements) among commercial new construction market actors (designers, builders, mechanical engineers, architects etc.)? • To what extent and through which activities is the CNC program influencing building design practices and the new construction market beyond incented projects?
4. Estimate gross energy and peak demand savings	• What are the gross and peak demand savings?
5. Estimate net energy and peak demand savings	• What are the net energy and peak demand savings for the overall CNC program? • What are the free ridership, participant spillover and non-participant spillover rates?

The data sources and analytical methods used to address the objectives are summarized in Table ES.2.

Table ES.2. Evaluation Objectives, Data and Methods

Evaluation Objective	Data	Methods
1. Assess the participant experience	• Participant Survey (n=57)	• Cross tabulations
2. Assess practices and opinions related to market transformation	• Market Actor Survey (n=13-30)	• Cross tabulations
3. Assess the influence of the program on the adoption of energy efficiency measures beyond building code requirements	• Market Actor Survey (n=13-30)	• Cross tabulations
4. Estimate gross energy and peak demand savings	• Program tracking data • Measurement and verification (n=12)	• IPMVP Option A, B and D • Ratio estimation • Peak demand savings based on peak-to-energy factor
5. Estimate net energy and peak demand savings	• Statistics Canada data on commercial new construction activity, F2012-F2016 • Participating building area (square metres) • Conservation Potential Review (CPR) Energy Use Intensity (EUI) inputs • Results from Objective 4 • Participant survey (n=51) • Market actor survey (n=13-30)	• Survey based free ridership and participant spillover algorithms • Market Actor Survey based non-participant spillover algorithm

Results

The results of the evaluation are presented by objective.

Results for Objective 1: Assess the participant experience

Among program participants, 79 percent reported being aware of the CNC offer by name. Of the individual program components, awareness, understanding and rating score was highest for the role that key account managers play as liaisons between CNC and participants.

Overall satisfaction was high for CNC at 80 percent, comprised of 41 percent stating they were very satisfied and 39 percent stating they were somewhat satisfied. When asked the likelihood of recommending the program to others, 95 percent indicated that they definitely (53%) or probably (42%) would, and 49 percent reported that they had in fact already done so.

A total of 80 percent of participants indicated that CNC was very (33%) or somewhat (47%) influential on the decision to implement the energy efficient measures at this site. Looking more broadly at conservation motivators, 60 percent of participants indicated that the CNC program was a 'major factor' in the organization's effort to manage electricity use over the past year. In terms of barriers to managing electricity use, lack of funds for energy efficient retrofits/projects was noted as a 'major barrier' by 33 percent of participants, followed by there being other operational priorities (29%) and lack of financial incentives for conservation programs and energy efficiency (26%).

Results for Objective 2: Assess practices and opinions related to market transformation

With regards to buildings that did not participate in the CNC program, but that market actors reported were performing better than the energy efficiency requirements of the B.C. Building Code, the most common type of design study conducted to help these buildings perform better than code was whole building design, with on average approximately two-thirds of respondents confirming that at least some floor area of their 'better than code, non-participating projects' had come through this study type. This was followed by lighting design studies, with about 44 percent of respondents, on average, confirming at least some floor area had come through this study type.

Again, with regards to buildings that did not participate in the CNC program but that were performing better than code, by far the most common measure being implemented to help make these buildings perform better than code was highly efficient lighting, with 83 percent of respondents reporting that the measure was at least sometimes implemented in their 'better than code, non-participating projects. This was followed by HVAC measures at 64 percent.

Market actors, including electrical engineers, mechanical engineers, energy modellers, architects and project managers, were asked how much they thought energy efficiency had improved in the entire commercial new construction market in B.C. over the past 10 to 15 years. All had thought that there had been some improvement over the past 10 to 15 years – although not necessarily beyond code – with the majority (55%) reporting a 20 percent improvement. Additionally, all thought that both their own buildings and those constructed by other firms were performing better than code specifically in regards to electricity savings. Savings were reported in the 1 percent to 30 percent range, with about half of respondents perceiving that their own buildings had 20 percent to 30 percent electricity savings relative to code, compared to only about one-third feeling the same way about buildings constructed by others.

Results for Objective 3: Assess the influence of the program on the adoption of energy efficiency measures beyond building code requirements

A total of 91 percent of respondents had experience with at least one of the energy efficiency resources or touchpoints provided by the program. The most common were *discussions about projects with BC Hydro staff* (70%) and *reviewing case studies/resource literature* (64%). This was followed by 60 percent who had *attended a program workshop or training session* and 40 percent who had re*viewed the Building Envelope Thermal Guide*. The least commonly used resource was the *Enhanced Thermal Performance Spreadsheet*, with only 21 percent of respondents indicating they had reviewed it.

Market actors were asked to consider all of their various touchpoints with the program and the influence that these had on their design decisions to have non-participating projects perform better than the building code. A total of 60 percent indicated that these program touchpoints were 'very' or 'somewhat' influential on their decisions to do so.

In order to understand program influence relative to other factors in the broader new construction context, market actors were asked to credit various factors for making non-program projects perform better than the B.C. Building Code, such that the factors summed to 100 percent. On average, BC Hydro 'drivers' were given a net of 24 percent of the credit for making projects perform better than code. It follows that non-BC Hydro drivers were given 76 percent of the credit for buildings performing better than code.

Another approach to assessing program influence was to query market actors on how much of the improvement in the energy use over time – although not necessarily beyond code – could be attributed to BC Hydro's Commercial New Construction program. About half (49%) felt it was in the 20 to 30 percent range, with the most common answer at 20 percent.

Results for Objective 4: Estimate gross energy and peak savings

The evaluated gross savings in fiscal year covered by the evaluation period are presented in Table ES.3. Evaluated gross electricity savings ranged from 9.2 GWh/yr to 24.2 GWh/yr from F2012 to F2016, with the most savings occurring in F2014 and the least occurring in F2012.

Table ES.3. Summary of Evaluated Gross and Net Energy and Peak Demand Savings

Year	Evaluated Gross Energy Savings (GWh/yr)	Evaluated Gross Peak Demand Savings (MW)	Calculated Net-to-Gross Ratio	Evaluated Net Energy Savings (GWh/yr)	Evaluated Net Peak Demand Savings (MW)
F2012	9.2	1.3	0.91	8.4	1.2
F2013	19.9	2.8	0.96	19.2	2.8
F2014	24.4	3.5	0.93	22.7	3.2
F2015	18.8	2.7	0.95	17.9	2.6
F2016	20.6	3.0	0.99	20.4	2.9
CNC (F12-F16)	**92.9**	**13.3**	**0.95**	**88.6**	**12.7**

Results for Objective 5: Estimate net energy and peak savings

The evaluated net savings in fiscal year covered by the evaluation period are presented in Table ES.4. Evaluated net electricity savings ranged from 8.4 GWh/yr to 22.7 GWh/yr from F2012 to F2016, with the most savings occurring in F2014 and the least occurring in F2012.

Table ES.4. Summary of Net Energy and Peak Demand Savings

	Net Energy Savings (GWh/yr)		Net Peak Demand Savings (MW)	
Fiscal Year	Reported	Evaluated	Reported	Evaluated
F2012	8.1	8.4	1.1	1.2
F2013	15.3	19.2	2.2	2.8
F2014	20.7	22.7	3.0	3.2
F2015	14.0	17.9	2.0	2.6
F2016	15.3	20.4	2.2	2.9
CNC (F12-F16)	**73.4**	**88.6**	**10.5**	**12.7**

The cumulative variance between the reported net energy savings and evaluated energy savings was 15.2 GWh/yr. The largest variance occurred in F2016 with a difference of 5.10 GWh between reported and evaluated savings.

Overall, the program achieved 121 percent of reported savings during fiscal years F2012 to F2016, showing the program performed better than reported. The variance between reported and evaluated net savings is primarily due to the impact of non-participant spillover which was estimated in the evaluation.

Findings and Recommendations

Findings

Participant Experience

1. Overall satisfaction was high for CNC at 80 percent, comprised of 41 percent stating they were very satisfied and 39 percent stating they were somewhat satisfied.

2. In terms of program experience, the highest scores related to aspects around service/communications from BC Hydro, as well as service provided by contractors. Mid-range scores typically related to aspects around the program offer (variety of products and level of incentives) and the overall application procedures. The lowest scores were for length of time to receive the incentive, length of time for the project/process to be completed and direct mail/email about the program (which was not relied on heavily by this program).

3. Participants reported that the program had been influential on their decision to implement the energy-efficient measures, with 33 percent indicating that it had been very influential and 47 percent indicating it had been somewhat influential.

Market Transformation

4. All market actors thought that there had been some improvement in the entire commercial new construction market in B.C. over the past 10 to 15 years – although not necessarily beyond code – with the majority reporting a 20 percent improvement in terms of energy use over time.

5. The most common types of design study conducted to help new construction projects perform better than code were whole building design and lighting design. The most common measures implemented to help projects perform better than code were lighting and HVAC.

Influence on Adoption of Energy Efficiency Measures Beyond Building Code Requirements

6. On average, BC Hydro 'drivers' were given a net of 24 percent of the credit for making projects perform better than code, with the largest credit given to previous learnings and experience with the CNC program. The remaining 76 percent of credit was given to non-BC Hydro drivers, with the largest given to general industry innovation/good practices and to clients directing the projects to be built as such.

Gross Electrical Energy Savings

7. The evaluated gross energy savings were 93 GWh/yr.

8. The program gross realization rate calculated using the inspected and verified results including cross effects was 1.06, indicating that the energy conservation measures largely performed better than expected. The realization rates by program offer were 1.17, 1.04, 0.89 and 0.89 for whole building design, system design, lighting design and program enabled projects, respectively.

9. Expected energy savings averaged 18 percent of site energy consumption across all participants during the five-year evaluation period.

Net Electrical Energy Savings

10. The evaluated net energy savings were 89 GWh/yr.
11. The net-to-gross ratio was 95 percent based on free ridership of 20 percent, participant spillover of 1 percent and non-participant spillover of 14 percent.
12. Evaluated net savings during the evaluation period from F2012 to F2016 averaged 121 percent of reported savings.

Recommendations

The following two recommendations are for future new construction initiatives:

1. Support and enabling activities for whole building energy modelling and integrated system approach to estimate a project's energy savings should continue and include the Building Envelope Thermal Bridging Guide and the Enhanced Thermal Performance Spreadsheet.
2. Future Market Actor surveys could be done more frequently so that respondents are better able to recall the projects they are being surveyed about.

Conclusions

BC Hydro's Commercial New Construction Program achieved high participant satisfaction. Evaluated net savings were 89 GWh/yr, which is 121 percent of reported savings. Evidence suggests that the program has supported the market in complying with and exceeding the energy efficiency requirements of the B.C. Building Code.

1.0 Introduction

Evaluation Scope

This impact evaluation presents the evaluated net electricity savings of the BC Hydro Commercial New Construction (CNC) program for fiscal years F2012 to F2016 (April 2011 to March 2016).

Due to the time it takes for construction, and occupancy of buildings, a fairly long delay was required before Measurement and Verification (M&V) of a representative sample of buildings that went through the CNC program could be completed. This is why the evaluation period goes back so far and stops at F2016. Additionally, this will mark the final evaluation of the CNC program as all active applications are scheduled to be completed in F2022 and no new applications are being accepted. Therefore, the remaining years of the program (F17-F22) will not be evaluated.

Organization of the Report

The organization of this report is as follows. Section 1 covers the evaluation scope, the organization of the report and the initiative description. Section 2 discusses the approach to the evaluation, including evaluation objectives, methodology review, data sources, and methods. Section 3 provides the results organized by evaluation objective. Section 4 provides findings and recommendations. Section 5 provides conclusions. Additional supporting material is contained in the appendices.

Initiative Description

The CNC Program was targeted at developers and the building design community who play a role in building and expanding commercial buildings in BC Hydro's service territory. Market actors included developers, building owners, architects, engineers, energy modellers and consultants. The key objectives of the CNC program were as follows:

1. Energy Efficient Design: Identify energy savings by promoting and funding the design of energy efficient buildings (i.e., more energy efficient than the building code legislation requires).
2. Energy Efficient Construction: Acquire energy savings by promoting the construction of energy efficient buildings and continued efficient operation.
3. Training and Recognition: Enable transformation of the market by training a team of industry professionals to act as energy conservation "ambassadors" (i.e., advocates) on all new construction projects that they work on in the future. In addition, publicly recognize energy efficient design teams and projects and create a market where consumers desire energy efficient buildings.
4. Advance Building Codes: Support the transformation of the new building market to higher sustained levels of energy efficiency and improved building code compliance. The program's activities help drive developer acceptance to a level where they are accepting of the next phase of more stringent building codes and standards introduced by government.

As noted in the fourth key objective above, the program was designed to support increases in the energy efficiency requirements in building codes. The term "code" or "building code" in this report refers specifically to the energy efficiency requirements of the B.C. Building Code or the Vancouver Building By-law. Although identified as part of the objective, any savings realized by meeting code requirements are not attributed to the program.

The program had 4 offerings:

1. Whole Building Design: Targeted at buildings over 50,000 square feet.
2. System Design: Targeted at improving the energy efficiency of selected buildings systems typically over 50,000 square feet.
3. Energy Efficient Lighting Design: Targeted at buildings typically over 10,000 square feet.
4. Program Enabled:
    - Projects in which the customer engaged with BC Hydro and undertook a funded Energy Study through which the building design/equipment was influenced, leading to energy savings. The savings for this offer were from customer-funded energy conservation measures. These measures are not incented due to not meeting BC Hydro cost effectiveness ratios or due to failing to comply with program incentive offer timing and process.

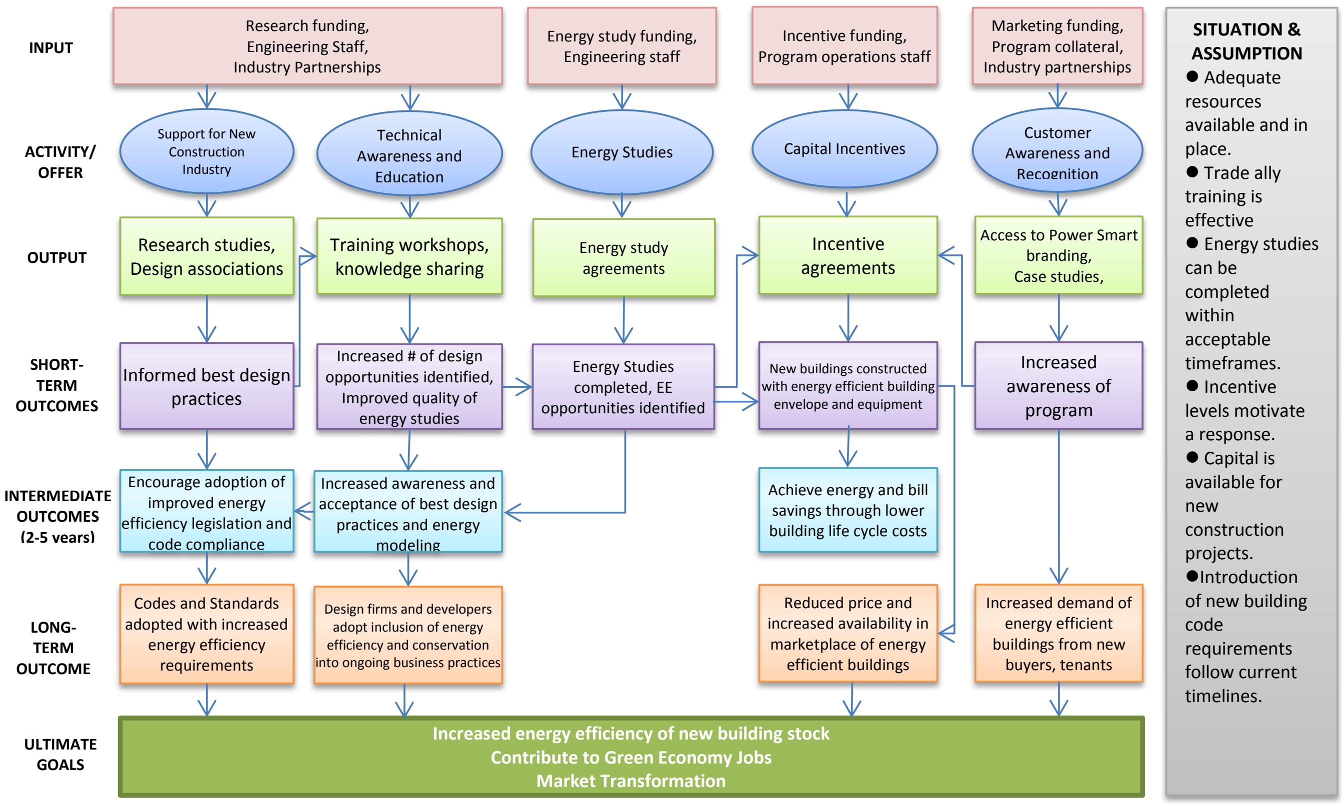
Table 1.1 Program Offers

	Whole Building Design ("Leaders')	System Design (Identified Too Late, Immature Mindshare)	Energy Efficient Lighting Design
Overview	Computer simulation of the whole building energy use	Energy use analysis of a specific system (e.g. lighting, refrigeration, HVAC)	Energy use analysis for lighting. Reduction of light power density requirement from building code though design and controls.
Target Market	• > 50,000 ft^2 ~> 50,000 kWh savings • Buildings with complicated systems • Engineered buildings • Market Leaders • Engaged developers in EE • Part 3 building code • Includes major renovations or major leasehold improvements	• >50,000 kWh savings • Buildings with complicated systems • Market Leaders & Followers • Engaged developers • Part 3 building code	• > 10,000 kWh savings • ~> 10,000 ft2
Building Types	• Office • Institutional • Multi unit residential building (MURB) • Commercial • Large retail	• Office • Institutional • MURB • Commercial • Large retail • Recreation • Supermarket	• Office • Institutional • MURB • Commercial • Large retail • Recreation • Supermarket
Applicable Components	• All electrical energy conservation measures, including building envelope	• All electrical conservation systems: o Lighting o HVAC o Refrigeration	• Lighting • Lighting controls
Incentive	• Fund Energy Study (100%) • Tiered Capital Incentive based on kWh saving	• Fixed Incentive based on kWh Saving • Select study funding (cap at $10k) on complex systems	• Fund lighting calculator (up to $1K) • Fixed Incentive based on kWh Saving

As noted above, the Commercial New Construction program is winding down, with all remaining applications scheduled to be completed in F2022. BC Hydro will continue to support the transformation of the commercial new construction market through codes and standards activities that support the B.C. Energy Step Code.

The program logic model depicts the main inputs, activities and outputs associated with program design and delivery as well as their connection to and the interconnections between the expected short, medium and longer-term outcomes. The logic model for CNC can be found below.

Figure 1.1. Logic Model



2.0 Approach

Evaluation Objectives

The evaluation addressed five objectives and their related research questions as presented in Table 2.1.

Table 2.1. Evaluation Objectives and Research Questions

Evaluation Objective	Research Questions
1. Assess the participant experience	• What is the level of participant awareness of the various CNC program components? • How do participants rate their program experience and overall satisfaction? • How influential is the CNC program on participant decisions around energy efficiency?
2. Assess practices and opinions related to market transformation	• What are the most common types of design studies being conducted in view of helping to make new construction projects perform better than code? (e.g., whole building energy modelling, a refrigeration system design study, and/or a lighting design study) • What are the most common measures being implemented to help make new construction projects perform better than code? • To what extent do market actors believe the commercial new construction market in the province has improved over the last 10-15 years? • How much electricity do market actors believe new construction projects are saving relative to the energy efficiency requirements in the B.C. Building Code?
3. Assess the influence of the program on the adoption of energy efficiency measures beyond building code requirements	• To what extent has the CNC program developed support for design and construction of more energy efficient buildings (beyond code requirements) among commercial new construction market actors (designers, builders, mechanical engineers, architects etc.)? • To what extent and through which activities is the CNC program influencing building design practices and the new construction market beyond incented projects?
4. Estimate gross energy and peak demand savings	• What are the gross and peak demand savings?
5. Estimate net energy and peak demand savings	• What are the net energy and peak demand savings for the overall CNC program? • What are the free ridership, participant spillover and non-participant spillover rates?

Methodology Review

A methodology review covering evaluation protocols and standards, as well as completed evaluations was undertaken to assess common methods used for evaluations of commercial new construction programs. Evaluations were identified through a search of various industry associations and energy program organizations, such as the U.S. Department of Energy, the California Measurement Advisory Council (CALMAC), the U.S. Department of Energy's Uniform Methods Project (UMP), the International Energy Program Evaluation Conference (IEPEC), the American Council for an Energy Efficient Economy (ACEEE), and the Northwest Energy Efficiency Alliance (NEEA). Past BC Hydro evaluations were also reviewed. Recommended evaluation methods are summarized below, along with common methods used in other evaluations.

In general, the recommended approach to estimating evaluated gross energy savings for new construction is to conduct M&V of a sample of projects, and extrapolate findings to the population of all projects. M&V methods included calibrated whole building modelling as well as sub-metering of individual energy end uses and systems, guided by the International Performance Measurement and Verification Protocol (IPMVP). The U.S. Department of Energy's Uniform Methods Project includes several protocols for determining energy efficiency savings for a variety of commercial and industrial end-uses and equipment measures including a protocol for new construction[1].

A literature review of evaluations from BC Hydro and other jurisdictions was conducted to inform this evaluation. The purpose of the literature review was to understand the scope, and evaluation methods employed in recent evaluations of new commercial construction programs. Studies were identified for potential inclusion in the literature review through a search of energy efficiency association websites as well as an internet search. To be included in this literature review, the study had to meet the following criteria: (1) the scope and objectives of the study had to be clear and well defined; and (2) the methods used to evaluate net and gross energy savings had to be clearly identified and transparent.

All of the studies examined focussed on verifying installation of equipment receiving an incentive, estimating gross savings for a sample of projects using suitable M&V methods, and aggregating individual project savings to estimate total gross savings. Most studies estimated a net-to-gross ratio using information from participant and trade ally surveys, typically multiple questions with an algorithm used to aggregate responses. The methods used to estimate gross savings were generally consistent with the IPMVP. Comparison and control groups were not employed in any of the evaluations reviewed.

The Uniform Methods Project protocol for evaluating net savings requires that, at a minimum, a free ridership adjustment is applied to evaluated gross savings[2]. The protocol also indicates that gross savings can be adjusted for spillover (participant and non-participant), but this is discretionary. An acceptable method outlined in the protocol for estimating free ridership and spillover is to use survey responses of program participants regarding the decisions they would have made in the absence of the program and how much the program influenced their decision to undertake specific energy savings activities. Free ridership estimates for programs that involved projects with complex, lengthy, multi-party decision making are increasingly derived using multiple lines of evidence. These lines of evidence commonly include participant survey data supplemented by information from sources such as program files, vendor surveys, or case studies. Using multiple lines of evidence to estimate free ridership in these complex situations has been the approach taken in BC Hydro's recent evaluations of its large industrial and new plant design programs due to small sample sizes and the complexity of decision-making around projects. Less common in other impact evaluations was the inclusion of an adjustment for spillover savings for participants and, particularly, for non-participants. Similar to the estimation of free ridership, the most common approach to estimating spillover was to use surveys of decision makers. Spillover was estimated this way for BC Hydro's most recent impact evaluations of BC Hydro's commercial and industrial programs[3].

[1] Uniform Methods Project: Chapter 15: Commercial New Construction Evaluation Protocol (September 2017)
[2] Uniform Methods Project, Chapter 21: Estimating Net Savings - Common Practices (October 2017)
[3] BC Hydro (2019). Leaders in Energy Management – Commercial: F2013-F2017; BC Hydro (2018). *Power Smart Partner – Industrial Distribution: F2011 to F2016*. BC Hydro (2017). *Power Smart Partner – Industrial Transmission: F2012 to F2014*.

Methodology

The data sources and methods used to address each evaluation objective are summarized in Table 2.2.

Table 2.2. Evaluation Objectives, Data and Method

Evaluation Objectives	Data	Method
1. Assess the participant experience	• Participant Survey (n=57 respondents)	• Cross tabulations
2. Assess practices and opinions related to market transformation	• Market Actor Survey (n=13-30)	• Cross tabulations
3. Assess the influence of the program on the adoption of energy efficiency measures beyond building code requirements	• Market Actor Survey (n=13-30)	• Cross tabulations
4. Estimate gross energy and peak demand savings	• Program tracking data • M&V (n=12)	• IPMVP Options A, B and D • Probability Proportional to Size (PPS) ratio estimation • Peak demand savings based on peak-to-energy factor
5. Estimate net energy and peak demand savings	• Statistics Canada data on commercial new construction activity, F2012-F2016 • Participating building floor area (sq. metres) • CPR, EUI inputs • Results from Objective 4 • Participant survey (n=51 projects) • Market actor survey (n=13-30)	• Survey based free ridership and participant spillover algorithms • Market Actor Survey based non-participant spillover algorithm

Data and Methods for Objective 1: Assess Participant Experience

The main source for addressing Objective 1 was an online survey of program participants, conducted in multiple waves. The first wave of the participant survey was fielded in May 2013 (covering projects completed in F2012), followed by a second wave in July/August 2014 (covering projects completed in F2013 and F2014). After that, the participant survey was conducted every six months on an ongoing basis in May and November (covering projects completed within the past 6 months). Details on the survey method are included in Appendix C.1 and questionnaire is included in Appendix F.

A total of 57 surveys were completed by F2012-F2016 program participants, representing an overall response rate of 41 percent and covering 20 percent of all square footage that came through the program. Although the returned sample was generally representative of the population based on known population parameters, the data were statistically weighted to further align it with the known population (by square footage and industry sub-sector for cross tabulations and by project savings for free ridership). Note that of the 57 survey respondents, only 51 were able to fully answer the free rider section. These 51 projects represented 17 percent of total projects completed and 18 percent of energy savings reported by the program during the evaluation period. The survey sample and population sizes by program offer are summarized in Table 2.3 on the following page.

Table 2.3. Participant Sample Size and Population

	Eligible Population	Surveys Sent	Responses Received	Response Rate	Margin of Error at the 95% Confidence Level
CNC Participants	284 sites	140	57	41%	+/- 11.6%

Data and Methods for Objective 2: Assess Practices and Opinions Related to Market Transformation

Objective 2 was addressed through results of a Market Actors Survey. This survey was administered in March 2018, aiming to solicit the views of professionals in British Columbia's commercial new construction industry who had decision making roles regarding the extent that their past projects would be energy efficient.

If not a key decision maker, candidates for this research were also screened based on the requirement to have held positions whereby they regularly provided inputs, alternate options and/or their opinions on the extent that their past new construction projects – those that became occupied between 2012 and 2016 – would be energy efficient.

The survey was conducted online due to the fact that a self-administered approach afforded these professionals the flexibility to complete it at their leisure and the time to formulate and express well-considered responses to the number of comprehensive questions being asked of them.

Potential candidates for this research were sourced via two parallel and complementary methods – one direct and one indirect. First, survey invitations were directly emailed to approximately 300 industry professionals for which business contact information (i.e., email addresses) was ascertained from internal databases and publicly available lists. Second, an invitation to participate in this research was indirectly made by embedding the communications into various industry association e-newsletters and online bulletin boards.

Ultimately, the final sample was comprised of 30 such professionals, primarily electrical engineers, mechanical engineers, energy modellers, architects and project managers. An accompanying response rate and margin of error is not presented due to the nature of the methodology and the fact that the total population size of eligible professionals is not specifically known with any certainty.

See Appendix C for more details in regards to this survey and Appendix E for the survey instrument.

Data and Methods for Objective 3: Assess the Influence of the Program on the Adoption of Energy Efficiency Measures Beyond Building Code Requirements

Objective 3 was addressed with the Market Actors Survey discussed above. Specifically, the survey asked industry professionals about drivers for making projects perform better than the energy efficiency requirements in the B.C. Building Code and BC Hydro influence.

Data and Methods for Objective 4: Estimate Gross Energy and Peak Demand Savings

In order to address Objective 4 and understand the estimation of evaluated gross savings, it is useful to understand the steps in the BC Hydro project cycle through which energy savings were initially estimated, then reviewed and verified for the different program components. The approach to estimate the evaluated gross energy savings include the following four steps and highlights the three components of the gross realization rate:

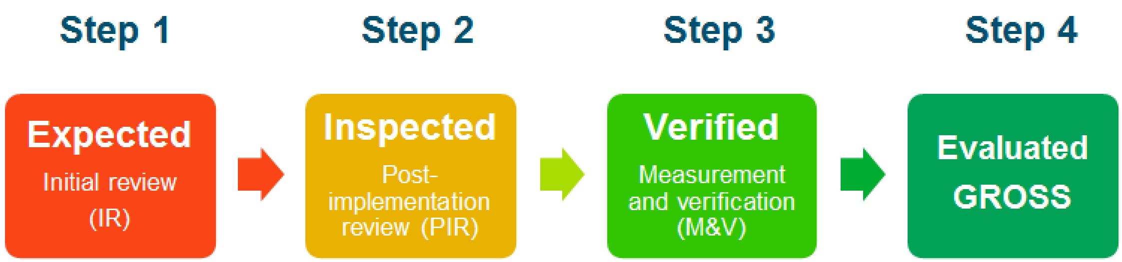
Step 1: Expected savings and initial engineering review.

Step 2: Inspected savings and component of realization rate for projects without post-implementation review.

Step 3: Verified savings and component of realization rate for projects without M&V.

Step 4: Evaluated savings and component of realization rate for cross effects where applicable.

Figure 2.1. Estimating Energy Savings Steps



In mathematical form, the gross evaluated savings were calculated by program offer according to the following equation.

Equation 1

$$Gross\ Evaluated\ Savings_j = Expected_i \times \left(\frac{Inspected}{Expected}\right)_j \times \left(\frac{Verified}{Inspected}\right)_j \times (1 - Cross\ Effects_j)$$

where $Expected_i$ is the expected savings for all projects (i) and the ratios were estimated from a sample of projects within each program offer (j)

Step 1: Expected Savings by Initial Review (IR)

All projects in the evaluation scope had an engineering review conducted by BC Hydro staff which was considered the expected energy savings for each measure in the project. In general, the initial engineering estimate of a project's energy savings was based on a technical application of engineering principles to forecast assumptions of hours of use and energy performance data. For the Whole Building Design and System Design offers, this estimate was documented in an energy study and resulted from whole building energy modelling or integrated system based energy calculation during design and construction. For the Lighting Design offer, the initial engineering estimate was based on a custom prescriptive approach and calculated by measure in the program lighting calculator tool using the applicable energy code as the baseline. For program enabled projects, the initial energy savings estimate was also based on an engineering estimate of a project's predicted energy savings before project implementation. Table 2.4 on the next page lists the count of projects, the count of measures and the expected savings by program offer.

Table 2.4. Expected Energy Savings by Program Offer

Program Offer	Approach	Count of Projects	Count of Measures	Expected Savings (GWh/yr)
Whole Building Design	Whole building energy modelling	95	665	53.4
Lighting Design	BC Hydro Lighting Calculator Tool	169	300	29.2
System Design	System based energy calculation	13	25	2.9
Program Enabled	Energy modelling or system calculation	7	35	1.8
Overall CNC F12-F16		**284**	**1,025**	**87.3**

Step 2: Inspected Savings by Post-implementation Review (PIR)

Energy savings estimates for most of the projects were refined through a post-implementation review (PIR). The purpose of the review is to confirm equipment installation and operation through various means such as examining customer-submitted project records and photos or physical site inspections. Not all projects in the Lighting Design offer were selected for post-implementation site inspections, especially if these projects were smaller in size and involved technologies with well-established engineering estimates.

Tag-on savings are energy savings that are generated above and beyond a project's original contract scope, for example when additional products are installed by the customer compared to what was outlined in the agreement. Tag-on savings do not impact incentives, but are recognized and reported by the program during post implementation review of lighting projects only. Tag-on energy savings were identified during post-implementation review on 11 projects for a total of 1,335 MWh per year.

Energy savings of projects without PIR were estimated based on the ratio of PIR over IR savings using ratio estimation method. The following table provides an overview of the coverage and method for estimation of these results.

Table 2.5. Coverage and Method of Post-implementation Review Savings by Program Offer

Program Offer	Coverage of Number of Projects with PIR	Coverage of Energy Savings with PIR	Method for estimation of (PIR/IR) ratio
Whole Building Design	100%	100%	Calculated
Lighting Design	89%	71%	Ratio estimation
System Design	100%	100%	Calculated
Program Enabled	100%	100%	Calculated

Step 3: Verified Savings by M&V

A subset of Whole Building Design and System Design projects was subject to M&V to validate the energy savings of the implemented measures. M&V was undertaken in accordance with the International Performance Measurement and Verification Protocol (IPMVP) for whole building design projects and inspired by IPMVP principles for system design projects. M&V involved energy modelling and simulation of variables that have a significant impact on energy consumption combined with post-implementation energy metering. To conduct this impact evaluation, a sample of twelve projects was selected for M&V. The sampling method used stratified sampling by savings magnitude and program offer for an overall target confidence of 80 percent and relative precision of 20 percent.

The fundamental equation for estimating energy savings is given by the following equation.

Equation 2: M&V Savings Estimation

$$\text{kWh Savings} = (\text{kWh}_{baseline} - \text{kWh}_{energy\ efficient}) \pm \text{Routine Adjustments} \pm \text{Non-Routine Adjustments}$$

where:

$\text{kWh}_{baseline}$ is the estimated baseline energy consumption of the system as determined by the energy study and/or engineering review completed as a condition of program participation

$\text{KWh}_{energy\ efficient}$ is the M&V estimate of consumption of the installed energy efficient system. This estimate is based on data collected using power meters, current transformer meters, or hours of use loggers, as well as verification of equipment counts through site visit.

Routine Adjustments are for any energy-governing factors, expected to change routinely during the reporting period, such as weather or schedule of operation.

Non-Routine Adjustments are for those energy-governing factors which are not usually expected to change, such as: the facility size, the design and operation of installed equipment, the number of weekly production shifts, or the type of occupants. These static factors must be monitored for change throughout the reporting period.

The approach to M&V differed between projects that went through the program's system design and whole building design offers.

System Design

Three projects that had participated in the system design offer underwent M&V using principles of IPMVP Option A and D[4]. Each project consisted of one or more conservation measures in energy efficient refrigeration systems at a unique building site. The M&V approach involved continuous measurements on a sample of components of the refrigeration system for a duration of three months, followed by engineering analysis to estimate the electricity savings from the energy conservation measures.

Whole Building Design

Nine building parcels that had participated in the whole building design offer underwent M&V using Option D of the IPMVP. The Cadmus Group and RDH Building Engineering Ltd. (RDH) were retained by BC Hydro to undertake this work. Under this approach, an "as-built" whole building energy simulation model was

[4] A combination of the concept of measure isolation (Option A) and calibrated simulation (Option D) was considered an acceptable approach as the engineering principles of the measures and systems are well established and control for the interactive effects within the system boundary through computer simulation.

developed based on the actual construction, systems, and operation of the building. The model was then calibrated such that it aligned with metered energy consumption data for the building. Once an acceptable calibration was achieved, a baseline model was developed by removing the energy conservation measures (ECMs) that went beyond building code requirements from the calibrated as-built model. Savings were determined by subtracting energy consumption for the calibrated as-built model from the calibrated baseline model. This M&V methodology is broken down into the following steps.

1. Data Collection: Information on the building is collected, including the design, as-built, and operating conditions, as well as metered utility energy consumption data (electricity and thermal energy). A site visit is conducted to meet with the building manager and review operational conditions.
2. Whole Building Energy Modelling: An energy simulation model of the building is developed based on the as-built and as-operated conditions determined through the data collection task. The model is calibrated to align with utility-metered energy consumption data by adjusting inputs that are not known with a high degree of certainty, such as plug loads. Modelling uncertainty[5] was determined using ASHRAE Guideline 141 for calibrating to monthly utility bills. Once an acceptable calibration has been obtained, a baseline or reference model is developed by removing energy conservation measures from the calibrated model.
3. Analyze results. Energy savings were determined by comparing the calibrated model to the baseline model and provide whole facility savings only. Energy savings of individual measures cannot be extrapolated due to the interactive effects.

Option D M&V controls for the effect of parallel DSM initiatives by using the measure level savings as an input to the analysis. The measure level savings were developed based on the engineering analysis of measures implemented through the CNC program, and only include savings that go beyond building code requirements. Option D M&V will produce savings estimates that include electricity cross effects, to the extent that they exist.

M&V Sample Coverage

The final M&V sample was assessed to compare it to the population of projects without M&V. The overall program M&V coverage was 7 percent in terms of electric energy savings, and it was estimated at 5 percent in terms of affected floor area. In order to extrapolate the M&V results to the population of projects that did not undergo M&V, projects were stratified according to the magnitude of their savings. The sample was drawn using the probability proportional to size method and the M&V results analyzed using ratio estimation by savings size in order to obtain the most reliable program realization rate estimate[6]. Results of sampling, confidence and precision are discussed in section 3.6.

[5] The Coefficient of Variation of the Root Mean Square Error (CVRMSE) must be less than 15%, while the Normalized Mean Bias Error (NMBE) must be less than 5%.

[6] The target for sampling error and ratio estimation is a confidence level of 80% or better with a relative precision of 20% or better.

The seven program enabled projects were a mix of whole building design and system design projects that were not included in the M&V sampling and therefore not evaluated using ratio estimation.

Table 2.6. Coverage and Method of M&V Savings by Program Offer

Program Offer	Coverage of Number of Projects with M&V	Coverage of Energy Savings with M&V	Method for estimation of (MV/PIR) ratio
Whole Building Design	9%	11%	Ratio estimation
Lighting Design	0%	0%	Estimated from LEM-C F13-F17
System Design	23%	18%	Ratio estimation
Program Enabled	0%	0%	Not evaluated

Ratio Estimation

Ratio estimation was used to calculate evaluated gross savings for three components of the program offers: PIR of Lighting Design projects, M&V of Whole Building Design projects, and M&V of System Design projects. Ratio estimation is a statistical method of extrapolating findings from projects with estimated results to projects without estimated results. Project samples of the three program offers were used to provide data inputs for ratio estimation for the components of realization rate. An overview of the steps involved in ratio estimation is provided below. For additional details, see Chapter 13 of the California Evaluation Framework[7]. The steps involved in determining evaluated gross savings using stratified ratio estimation are described below.

First, the realization rate sample for each of the three program offers was stratified to improve the statistical validity of the resulting estimate of evaluated gross savings. Three strata were selected, based on project savings size. These are shown in Table 2.7.

Table 2.7. Stratification of Components of Realization Rate by Project Size and Program Offer

Strata	Lighting Design Inspected Savings	Whole Building Design Verified Savings	System Design Verified Savings
1	< 0.07 GWh/yr	< 0.2 GWh/yr	< 0.1 GWh/yr
2	0.07-0.70 GWh/yr	0.2-0.75 GWh/yr	0.1-0.2 GWh/yr
3	0.70-2.3 GWh/yr	0.75-4.0 GWh/yr	0.2-0.4 GWh/yr

Second, case weights were calculated for each stratum. Case weights, also known as probability weights, are used to reduce bias when working with sample data. Case weights represent the probability that a project was selected into the ratio estimation sample from the population of projects in the strata, as per Equation 3. Higher case weights indicate that relatively few projects were found in the ratio estimation sample. Weightings applied to the savings in each stratum improve the statistical significance of the resulting ratio estimation.

[7] TecMarket Works, et. al., 2004.

Equation 3

$$Weighting\ (w_i) = \frac{N}{n}$$

Where: (N) is the number of measures in the population
(n) is the number of measures in the realization rate sample

Weightings for the ratio estimation samples are shown below.

Table 2.8. Weighting by Strata and Ratio Estimation Sample

	Lighting Design Inspected Ratio (PIR/IR)			Whole Building Design Verified Ratio (M&V/PIR)			System Design Verified Ratio (M&V/PIR)		
Strata	Population Count, N	Sample Count, n	**Weighting (N/n)**	Population Count, N	Sample Count, n	**Weighting (N/n)**	Population Count, N	Sample Count, n	**Weighting (N/n)**
1	89	89	**1.0**	27	2	**13.5**	3	1	**3.0**
2	76	58	**1.3**	48	3	**16.0**	5	1	**5.0**
3	4	4	**1.0**	20	4	**5.0**	5	1	**5.0**

Third, the required ratios were calculated according to Equation 4.

Equation 4

$$Ratio\ Estimate\ (RE)_j\ = \frac{\sum_{i=1}^{n} w_i y_i}{\sum_{i=1}^{n} w_i x_i}$$

Where: The summation is over all projects from the ratio estimation sample for program offer (j)
w_i is the case weighting of the stratum for project (i), derived from Equation 1
y_i is the known PIR or M&V savings for project (i) in the realization rate sample
x_i is the known IR or PIR savings for project (i) in the ratio estimation sample

Fourth, each of the three ratio estimation results was tested for statistical validity. Equation 5 was used to estimate the standard error of the ratio estimate, Equation 6 was used to estimate the error bounds at the 90 percent confidence level, and Equation 7 was used to estimate the relative precision, also at the 90 percent confidence level. The definitions of the terms in Equation 5 are the same as for Equations 3 and 4.

Equation 5

$$Standard\ error\ of\ GRR, se(GRR)_j = \frac{1}{\sum_{i=1}^{n} w_i x_i}\sqrt{\sum_{i=1}^{n} w_i(w_i - 1)(y_i - bx_i)^2}$$

Equation 6

$$Error\ bounds, eb(GRR)_j = \pm 1.645 * se(GRR)$$

Equation 7

$$Relative\ precision_j = \frac{eb(GRR)}{GRR}$$

Step 4: Evaluated Savings and Gross Realization Rates

Finally, the gross realization rate was estimated for each of the four program offers using the three components of realization rate and calculated according to Equation 8.

Equation 8

$$Gross\ Realization\ Rate\ (GRR)_j = \left(\frac{PIR}{IR}\right)_j \times \left(\frac{MV}{PIR}\right)_j \times (1 - CE_j)$$

Where: *Gross realization rate* was calculated for each program offer (j) and
(PIR/IR) is the ratio of post-implementation review savings to the initial review savings;
(MV/PIR) is the ratio of M&V savings to the post-implementation review savings;
and *CE* is the factor for cross effects where applicable.

Cross Effects (CE)

Gross savings for Lighting Design projects were adjusted for cross effects in accordance with BC Hydro's Standard Procedure for Cross Effects[8]. BC Hydro's commercial programs apply cross-effects only to lighting end-uses. Cross effects are estimated by breaking down lighting savings by building type and computing a weighted average HVAC Interactive factor for each building type based on tabulated values of HVAC interactive factors for different HVAC system types, weighted according to the prevalence of each HVAC system type in the commercial sector. Cross effect assumptions were applied only to evaluated gross savings of the lighting design projects.

The following table provides the summary of the applicability and method for cross effects by program offer.

Table 2.9. Applicability and Method for Cross Effects by Program Offer

Program Offer	Applicability of Cross Effects (%-Lighting savings)	Method for estimation of Cross Effects (CE)
Whole Building Design	30%	Included in M&V
Lighting Design	100%	BC Hydro Standard: Cross Effects
System Design	0%	Included in M&V
Program Enabled	28%	Not evaluated

[8] BC Hydro Standard Procedure: Cross Effects, August 2013

The table below summarizes how the parameters of the gross realization rate were determined for each program offer (i.e., calculated directly or through ratio estimation, included in M&V, or estimated from other data sources).

Table 2.10. Components of Gross Realization Rate by Program Offer

Program Offer	Step 1 Expected Savings	Step 2 (PIR/IR)	Step 4 (M&V/PIR)	Step 4 (CE)
Whole Building Design	Program data	Calculated	Ratio Estimation	Included in M&V
Lighting Design	Program data	Ratio estimation	Assumed*	Estimated
System Design	Program data	Calculated	Ratio Estimation	Included in M&V
Program Enabled	Program data	Calculated	Not evaluated	Not evaluated

* Assumed from BC Hydro LEM-Commercial Impact Evaluation F2013-F2017

The last step was to calculate the evaluated gross energy savings of the program from the gross realization rate and expected savings for all projects in each of the four program offers according to the following equation.

Equation 9

$$Evaluated\ Gross\ Savings_j\ \left(\frac{GWh}{yr}\right) = \sum Expected\ Savings_i\ \left(\frac{GWh}{yr}\right) \times GRR_j$$

Where the summation is over all projects (i) in each program offer (j).

Gross Peak Demand Savings

Peak demand savings were estimated by applying an average peak-to-energy factor derived by CEM Strategic Planning from the commercial rate class load shape, as more refined data on peak savings was not available. For the purpose of this evaluation, the average peak-to-energy factor was 0.143 MW per GWh. This approach introduces uncertainty because it relies on the assumption that energy savings have the same annual shape as the associated load shape, but this may not be true for unique projects and sites.

Baselines

The baseline represents the energy that would have been used without implementation of the energy efficiency project. The baseline energy consumption of a new commercial building is, by necessity, theoretical. Baselines were determined through engineering analysis during the building design, using the building code and relevant codes and standards that were in place at the time of building design as input into the selected building energy modeling software to determine the baseline consumption.

Threats to Validity

Projects without M&V results were the main threat to the validity of evaluated gross savings. Evaluated gross savings for whole building design and system design projects without M&V results were estimated using a gross realization rate, as described above. This can create some uncertainty if the realization rate is not representative of the population. M&V results were only available for a small sample of projects. To mitigate this threat to validity, the gross realization rate was segregated in its three components and each component was tested through estimation of its relative precision.

There were no M&V results available for any Lighting Design projects in the program which introduces uncertainty in the component of gross realization rate for this program offer. To mitigate this threat to validity, the (M&V/PIR) results of similar lighting projects from the recent impact evaluation of the BC Hydro commercial program[9] were used.

Peak demand savings were estimated by applying a peak-to-energy factor derived from the commercial rate class load shape. This approach introduces uncertainty because it relies on the assumption that energy savings have the same annual shape as the associated load shape, but this may not be true for unique projects and sites.

Data and Methods for Objective 5: Estimate Net Energy and Peak Demand Savings

Gross savings do not account for factors external to the program that could impact energy savings and may include energy savings that are not attributable to the program. The evaluated net savings are attributable to the program and include adjustments for free-ridership of participants and spillover of participants and non-participants. Net electricity savings were determined through the following equation:

Equation 10

$$Evaluated\ Net\ Savings\ = Evaluated\ Gross\ Savings\ \times\ (1 - Free\ Rider\ Rate + Spillover\ Rate)$$

Free Ridership

Online surveys of program participants were employed to estimate the savings that were attributable to the CNC program using a self-report approach. As mentioned previously, of the 57 survey respondents, only 51 were able to fully answer the free rider section. These 51 projects represented 17 percent of total projects completed and 18 percent of energy savings reported by the program during the evaluation period. To ensure that survey respondents had the appropriate level of decision making authority for the purpose of this study, a number of questions were asked to determine key characteristics of the respondent and of their facility. In order to estimate free ridership, program participants were asked a series of questions about the counterfactual – what the organization would have done at the site in the absence of the program. First, participants were reminded of the energy conservation measures that were undertaken at the site with assistance from the program. Participants were then asked a series of sequential questions about what they would have implemented without enabling activities or incentives from the program. A decision tree was used to assign free rider scores based on responses to these questions (see Appendix C.3). Free ridership results were weighted based on evaluated gross savings and extrapolated to the project population.

Participant Spillover

In order to estimate participant spillover, survey respondents were once again reminded about the projects they had already completed with assistance from the program. They were then asked to indicate the number of end-uses or technologies that they had upgraded on their own and a series of questions about the program's influence on their decision to do so. A decision tree was used to assign spillover scores based on responses to these questions (see Appendix C.3). Responses were then converted to a metric that is comparable with the free rider score by applying typical energy savings associated with the upgraded end-use or technology, adjusting those savings by the influence of the program, and then comparing those savings to total program savings.

[9] BC Hydro (2019) Leaders in Energy Management - Commercial Program Evaluation

Non-Participant Spillover

Non-participant spillover pertaining to the entire five year evaluation period of interest was estimated via a calculation involving both empirical and survey-based inputs.

To begin, the total commercial new construction building stock in British Columbia – projects that first became occupied between 2012 and 2016 – that could have possibly been influenced by BC Hydro's program was ascertained from Statistics Canada permit data together with costing estimates from Hanscomb Quantity Surveyors. Specifically, this estimate of the total building stock is measured in floor area and was computed by aggregating the dollar values of new construction permits issued for the buildings that became occupied during this period, and dividing this total dollar value by Hanscomb's estimate of construction costs given as dollars per square meter.

As shown in row A of Table 2.11, this total floor area is comprised of all new construction projects during this period – including those that may have received program funding (i.e., participants).

Next, the total commercial new construction building stock during this period that did receive program funding was ascertained from program tracking data. This too was summarized in floor area and is shown in row B.

Through the five years of the evaluation, the commercial new construction building stock that did not receive program funding – and was, therefore, eligible for non-participant spillover savings – is shown in row C as the value of A minus the value of B.

Table 2.11 Non-Participant Spillover Methodology

A.	Commercial new construction building stock in BC that could have been influenced by the program F12-F16 (m^2)	A
B.	Commercial new construction building stock that did receive BC Hydro program funding F12-F16 (m^2)	B
C.	Commercial new construction building stock that did <u>not</u> receive BC Hydro program funding F12-F16 (m^2)	C = A – B
D.	Percent of commercial new construction building stock that exceeds code F12-F16 (%)	D
E.	For commercial new construction building stock that exceeds the B.C. Building Code, the average unit electricity savings relative to the code (kWh/m^2)	E
F.	Attribution of electricity savings to BC Hydro's Commercial New Construction Program (%)	F
G.	Non-Participant Spillover F12-F16 (GWh)	$G = \frac{C \times D \times E \times F}{1,000,000}$

The Market Actors Survey was then leveraged for three additional inputs. First, findings from the survey were used to estimate the percentage of commercial new construction floor area in this period that exceeded the B.C. Building Code (row D). Second, findings from the survey – together with end-use intensity data from BC Hydro's 2016 Conservation Potential Review (CPR) – were used to estimate average unit electricity savings for the floor area that exceed the code (row E). Third, findings from the survey were used to estimate the attribution of gross electricity savings from non-participants back to the Commercial New Construction Program (row F).

It follows that non-participant spillover (row G) was estimated as the product of the values in rows C, D, E and F, divided by 1,000,000 to yield gigawatt-hour savings (GWh).

See Appendix C.3 for more details about this estimation of non-participant spillover, particularly in regards to the calculation of the inputs D, E and F.

Threats to Validity

Threats to the validity of the survey-based methods to estimate free ridership, participant spillover and non-participant spillover in this study were tied to three types of potential bias: 1) response bias, 2) recall bias, and 3) non-response bias.

1. Response Bias

Response bias can occur when the structure of the survey, the presentation of information in the survey, the survey questions and/or the response options influence the responses of customers away from accurate or truthful responses. This potential source of bias was mitigated in the Participant Survey and the Market Actors Survey by administering what is believed to be well-structured, well-ordered, unambiguous and non-leading questions together with balanced response scales that covered the potential range of customer opinion.

One particular type of response bias is 'social desirability response bias' whereby respondents provide answers that they believe an interviewer may want to hear and/or answers that they believe are consistent with the preferred outcome of the study. For each of the two surveys, this potential source of bias was mitigated by utilizing self-administered online surveys rather than an interviewer led approach.

2. Recall Bias

Recall bias – in the most typical of scenarios – can occur when respondents' recollection and opinions of events and/or experiences from the past are 'clouded' by the passage of time giving way to potentially inaccurate responses.

For the Participant Survey, this potential source of bias could emerge if respondents do not remember the project in question and the accompanying approval process. However, it was managed first by administering the survey every six months through the evaluation period whereby customers that completed projects were queried about them no more than six months thereafter. Additionally, the survey presented respondents with detailed descriptions of their projects undertaken at their site. If respondents were not aware of the project, they were skipped around the section on free ridership, and were excluded from the free rider calculation.

As the Market Actors Survey was administered just once at the end of this evaluation period, the sample and findings were potentially prone to recall bias as respondents were asked about their projects that became occupied from 2012 through to 2016. This necessarily meant them trying to recollect design decisions that were made two to three years even before construction and subsequent occupation. This potential source of bias was mitigated by the intuitive layout and flow of the survey, presenting questions in a series of small, logical steps to solicit recollections and opinions.

Additionally, because the survey was self-administered, it afforded respondents the flexibility and time to retrieve and review planning files pertaining to their past commercial new construction projects. In fact, there is anecdotal proof that many respondents did just this.

3. Non-Response Bias

Non-response bias can occur when subjects comprising the final survey sample are significantly different in the key exploratory parameters of interest than eligible subjects in the same population who did not complete a survey. These responders may be different than non-responders on these exploratory parameters because their demographic, geographic, attitudinal or behavioural makeup is different. This can render the survey sample not wholly representative of the population.

For the Participant Survey, this potential source of bias may materialize if the survey respondents and their views are significantly different than all others, particularly if they are not qualified in the first place to be commenting on their organization's decision-making criteria. This potential source of bias was mitigated in two ways. First, it was managed by sending the survey to all available program participants and promoting high response rates through survey completion incentives and multiple reminders to complete the survey. Second, it was further managed by screening respondents by job title and decision-making authority. See Appendix C.1 for this information.

For the Market Actors Survey, non-response bias was plausible due in large part to the fact that the sample was comprised of 30 industry professionals of interest – a fraction of the likely hundreds of them working in British Columbia's commercial new construction marketplace. In fact, some of the inputs into the calculation of non-participant spillover were based on the responses of as few as 13 individuals. Their views in regards to the industry and their attribution of the advancement of energy efficiency back to BC Hydro may not be representative of all professionals who were eligible to complete the survey.

However, proving the existence or non-existence of non-response bias in a survey sample requires either 1) a follow-up survey sample of the non-responders or 2) an understanding of the true population distribution of the exploratory parameters of interest. Follow-up surveys with non-responders are very rarely conducted because they often incur additional costs, extend research timelines, and most often come with their own group of non-responders. Having an understanding of the true population distribution of the exploratory parameters before embarking on a survey is generally rare – the absence of this information is the very reason for conducting the survey in the first place.

Alternative Methodologies

An alternative approach explored in the estimation of gross realization rates for the CNC program was to use M&V results at the energy conservation measure level to estimate separate gross realization rates by end use. This approach was abandoned due to the cost of conducting the M&V at the measure level instead of the project level, concerns about the small number of measures with M&V results in each sample, and the difficulty in estimating the cross effects between end uses.

Analysis of load shapes and interval data of buildings together with benchmarking energy use indices for buildings was also considered but many of the buildings were multi or mixed-use and therefore difficult to compare by building type and space function.

3.0 Results

Participant Experience

Program Components. Among program participants, 79 percent reported being aware of the CNC offer by name. Of the individual program components, awareness was highest for the role that key account managers play as liaisons between CNC and participants at 74 percent. Awareness of the basics of the energy study component and the project incentive structure were equal at 63 percent each.

Table 3.1. Awareness of Program and Components

	CNC Participants (n=57)
Overall awareness of CNC offer	**79%**
Key Account Managers' role as liaison between CNC and participants (among those with a KAM; n=45)	74%
Energy study component of CNC	63%
Project incentive structure of CNC	63%

Among those aware of individual program components, the highest level of understanding was for the role that key account managers play as liaisons between the program and participants with 87 percent reporting an excellent or good understanding. Understanding of the energy study component was more moderate at 72 percent, followed by understanding of the project incentive structure at 66 percent.

Table 3.2. Understanding of Program Components (Excellent + Good)

	CNC Participants (n=57)
Key account mangers' role as liaison between CNC and participants (among those with a KAM; n=33)	87%
Energy study component of CNC	72%
Project incentive structure of CNC	66%

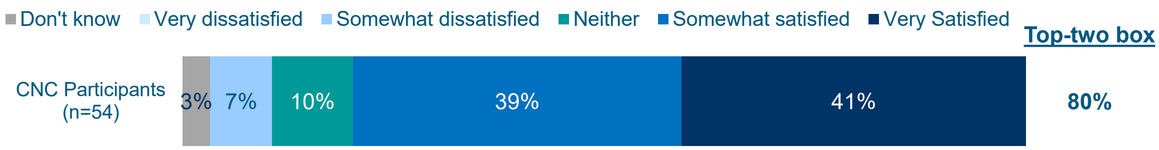
The rating of key account managers in relation to their support of participation in CNC was very high with 100 percent providing an excellent (60%) or good (40%) rating. The overall rating of the project incentive structure was also high with 83 percent providing favourable rating, but with only a small proportion providing an excellent rating (3%) and the balance (80%) providing a good rating. Although the energy study component had a lower combined excellent plus good rating of 72 percent, it had a higher proportion rating it as excellent (20%).

Table 3.3. Rating of Program Components (Excellent + Good)

	CNC Participants (n=57)
Key account managers in relation to their support of participation in CNC (among those with a KAM; n=33)	100%
Project incentive structure of CNC	83%
Energy study component of CNC	72%

Overall Satisfaction. Overall satisfaction was high for CNC at 80 percent, comprised of 41 percent stating they were very satisfied and 39 percent stating they were somewhat satisfied. Results were examined by year, but there were no clear trends over time. When asked the likelihood of recommending the program to others, 95 percent indicated that they definitely (53%) or probably (42%) would, and 49 percent reported that they had in fact already done so.

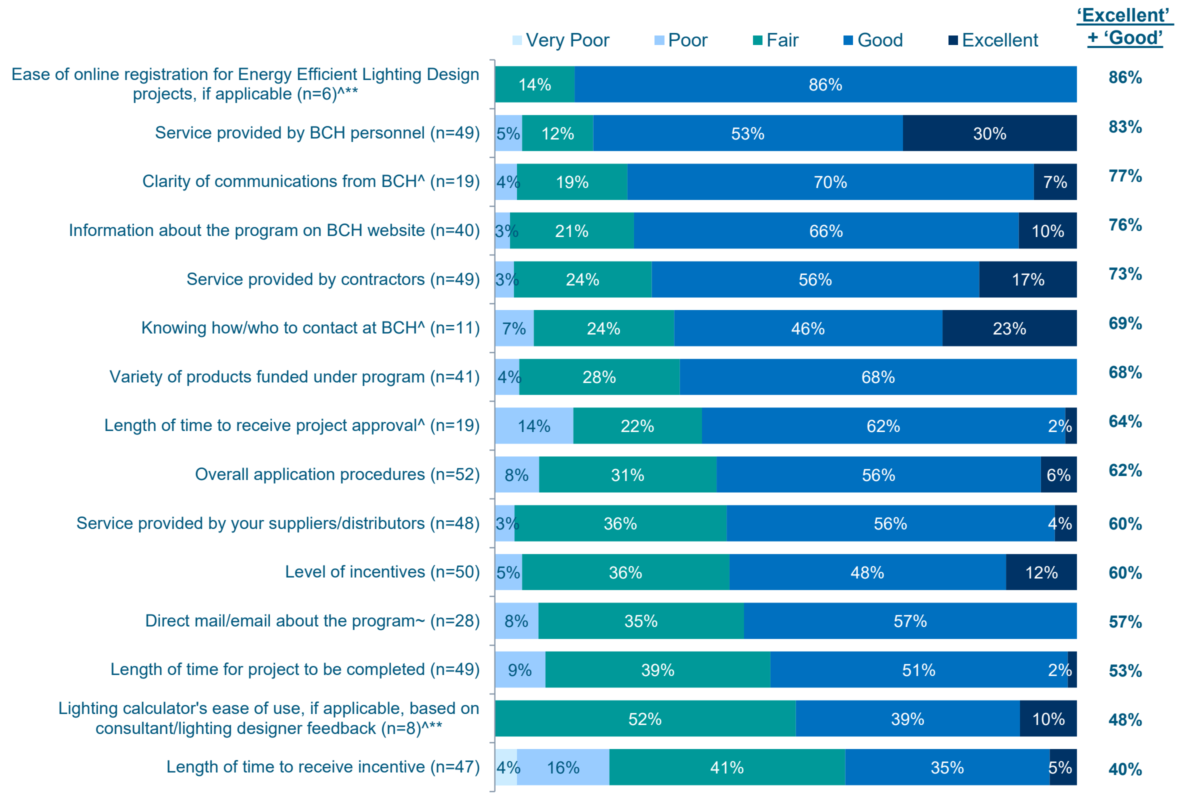
Figure 3.1. Overall Satisfaction



Program Experience. Program participants were asked to provide an overall rating from 'very poor' to 'excellent' on a five-point scale for various aspects of their experience with the program.

- **Service** – While service provided by BC Hydro personnel rated very favourably with 83 percent rating it as excellent or good, service provided by contractors and suppliers/distributors was lower at 73 percent and 60 percent, respectively. Service provided by BC Hydro had the highest excellent score of all individual aspects at 30 percent.
- **Customer Contact** – 'Clarity of communications from BC Hydro' also rated well with 77 percent rating it as excellent or good. Although 'knowing who to contact at BC Hydro' rated lower at 69 percent, it had a higher proportion rating it as excellent (23%).
- **Program Information** – Both 'information about the program on the website' and 'information about program via direct mail/email' had a large proportion of respondents answering 'don't know' to these questions (25% and 43%, respectively), presumably because they had not looked for program information on the website or did not recall receiving any direct mail/email about the program. Among those providing a rating, information on the website was rated favourably at 76 percent, while directly mail/email, which was not relied on heavily by the program, was rated lower at 57 percent.
- **Program Offer** –The 'variety of products funded under the program' and 'level of incentives offered' were rated moderately at 68 percent and 60, respectively.
- **Application Process** – The 'overall application procedures to receive funding' was also rated moderately with 62 percent rating it as either excellent or good.
- **Length of Time** – Aspects related to length of time were among the lowest rated of all aspects, with 'length of time to receive project approval' at 64 percent, 'length of time for project/process to be completed' at 53 percent, and 'length of time to receive incentive' receiving the lowest score of all aspects at 40 percent.
- **Lighting design** – Two new questions about lighting design projects were added to the survey in F2016. Although sample sizes for these questions are small and the results should be interpreted with caution, directionally, the results suggest that 'ease of online registration for Energy Efficient Lighting Design projects' was rated more favourably than the 'lighting calculator's ease of use' (based on feedback they had received from their consultant/lighting designer).

Figure 3.2. Ratings of Program Experience



Note: 'Don't know' responses are excluded and range from 3% to 43%. ^New questions added in F2015 and F2016. ~Wording updated to include 'email' in F2016. **Small sample size.

Influence of CNC on Energy Efficiency Decisions. The influence of the CNC program on participant decisions around energy efficiency can be gleaned from various questions in the participant survey. A direct question asking about program influence on the decision to implement the specific energy efficient measures funded by the program was used in the decision tree for calculating free ridership. For this question, a total of 80 percent of participants indicated that CNC was very (33%) or somewhat (47%) influential on the decision to implement the energy efficient measures at this site (n=51).

To understand changes in customer awareness of energy conservation measures and opportunities, participants were asked about their organization's prior experience with the energy-efficient measure or technology that was installed though the program. While 10 percent had a great deal of experience and 39 percent had a fair amount of experience, similar amounts had only a little (37%) or no experience at all (12%) with the energy-efficient measure (n=51).

Looking more broadly at conservation motivators, 60 percent of participants indicated that the CNC program was a 'major factor' in the organization's effort to manage electricity use over the past year (n=10)[10]. In terms of barriers to managing electricity use, lack of funds for energy efficient retrofits/projects was noted as a 'major barrier' by 33 percent of participants, followed by there being other operational priorities (29%) and lack of financial incentives for conservation programs and energy efficiency (26%) (n=22).

See Appendix D for additional findings from the survey research.

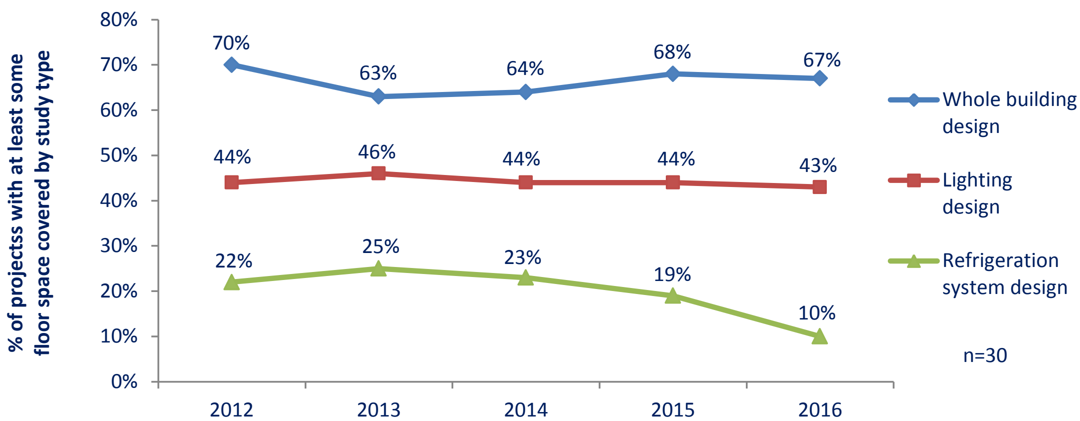
[10] The small sample size is due to a change in the response scale for this question during the evaluation period (from a 5-point influence scale to a 3-point major/minor scale) and due to the motivators/barriers question not being asked each wave due to survey length.

Practices and Opinions Related to Market Transformation

This section assesses the extent and the ways through which the new construction market is performing better than the B.C. Building Code.

With regards to buildings that did not participate in the CNC program, but that market actors reported were performing better than the energy efficiency requirements of the B.C. Building Code , the most common type of design study conducted to help these buildings perform better than code was whole building design, with on average approximately two-thirds of respondents confirming that at least some floor area of their 'better than code, non-participating projects' had come through this study type. This was followed by lighting design studies, with about 44 percent of respondents, on average, confirming at least some floor area had come through this study type. It comes expectedly that refrigeration system design studies were the least common given that not all construction projects would have had this end use.

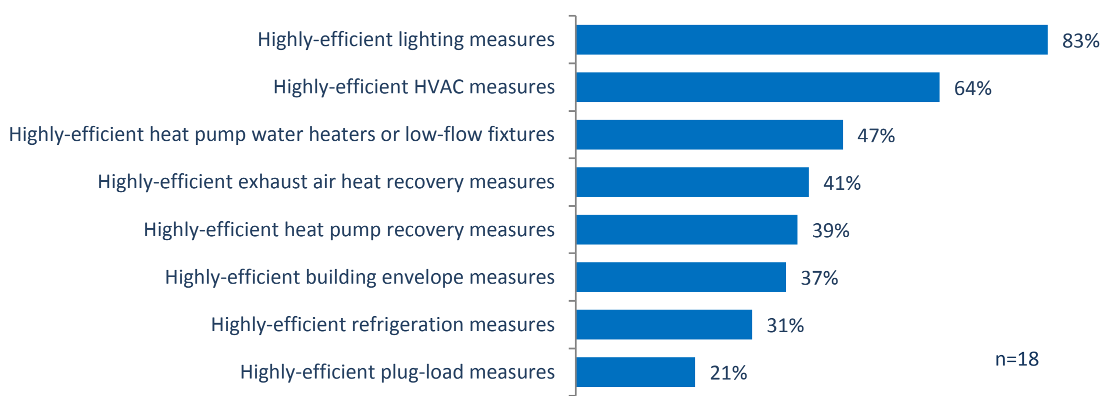
Figure 3.3. Most Common Types of Design Studies (percent of respondents with 'better than code, non-participating projects' that had at least some floor area receive the study type)



Note: because some respondents answered 'don't know' to these questions, results shown are for confirmed studies, and values thus could measure higher.

Again, with regards to buildings that did not participate in the CNC program but that were performing better than code, by far the most common measure being implemented to help make these buildings perform better than code was highly efficient lighting, with 83 percent of respondents reporting that the measure was at least sometimes implemented in their 'better than code, non-participating projects'. This was followed by HVAC measures at 64 percent; all remaining measures were below 50 percent.

Figure 3.4. Measures Implemented in 'Better than Code, Non-Participating Projects' (percent of respondents reporting that the measure was at least sometimes implement in their 'better than code', non-participating projects)



Market actors were asked how much they thought energy efficiency had improved in the entire commercial new construction market in B.C. over the past 10 to 15 years. All had thought that there had been some improvement – although not necessarily beyond code – with the majority (55%) reporting a 20 percent improvement in terms of energy use over time.

Table 3.4. Perceived Improvement in Energy Efficiency in Terms of Energy Use of Entire Commercial New Construction Market in B.C. Over Time (2012 – 2016 compared to 2005 – 2011)

	n=30
0% - no better	0%
1% - 9% better	5%
10% better	15%
20% better	55%
30% better	10%
40% better	10%
50% + better	4%
Don't know	3%

Market actors were also asked how much they thought projects completed by their own organization and by other organizations were performing relative to the energy efficiency requirements of the B.C. Building Code in terms of electricity savings. All thought that both their own buildings and those constructed by other firms were performing better than code, with organizations perceiving their own projects as performing better than those constructed by others. Savings were reported in the 1 percent to 30 percent range, with about half of respondents perceiving that their own buildings had 20 percent to 30 percent electricity savings relative to code, compared to only 36 percent feeling the same way about buildings constructed by others.

Table 3.5. Perceived Electricity Savings of Commercial New Construction Projects Relative to the Energy Efficiency Requirements in the B.C. Building Code (2012 to 2016)

n=23	Own Projects		All Other Projects in B.C.	
0% electricity savings (the projects would be performing to the energy efficiency requirements in the B.C. Building Code)	0%		0%	
1% - 9% electricity savings	18%		26%	
10% electricity savings	13%		13%	
20% electricity savings	35%	**48%**	27%	**36%**
30% electricity savings	13%		9%	
40% electricity savings	0%		0%	
50% + electricity savings	0%		0%	
Don't know	21%		24%	

Influence of the Program on the Adoption of Energy Efficiency Measures Beyond Building Code Requirements

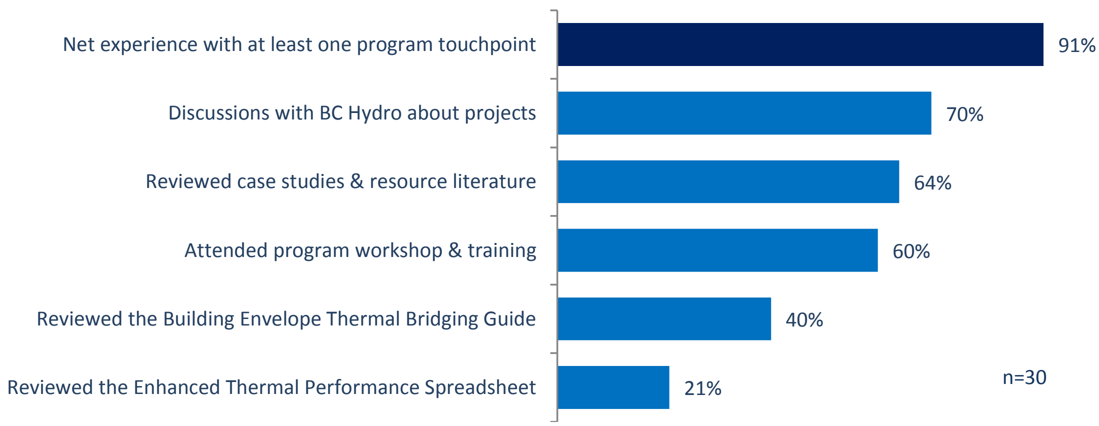
This section assesses the extent to which the CNC program has influenced building design practices and the new construction market beyond incented projects.

The CNC program developed tools to support the industry design and construct more energy efficient buildings (beyond code requirements), including:

- Workshops and training – sometimes in partnership with industry associations – in regards to new building construction;
- Case studies and resource literature in regards to new building construction posted on BC Hydro's website;
- The Building Envelope Thermal Bridging Guide[11] which BC Hydro sponsored and contributed to, and which details how the commercial new construction market can effectively account for the impact of thermal bridging as part of meeting the challenges of reducing energy use in buildings;
- The Enhanced Thermal Performance Spreadsheet[12], which BC Hydro provided technical support and funding for and which is included in BC Hydro's energy modelling guidelines; and
- Discussions with BC Hydro staff about projects aside from the interactions at workshops and other formal events.

A total of 91 percent of respondents had experience with at least one of the energy efficiency resources or touchpoints provided by the program. The most common were *discussions about projects with BC Hydro staff* (70%) and *reviewing case studies/resource literature* (64%). This was followed by 60 percent who had *attended a program workshop or training session* and 40 percent who had re*viewed the Building Envelope Thermal Guide*. The least commonly used resource was the *Enhanced Thermal Performance Spreadsheet*, with only 21 percent of respondents indicating they had reviewed it.

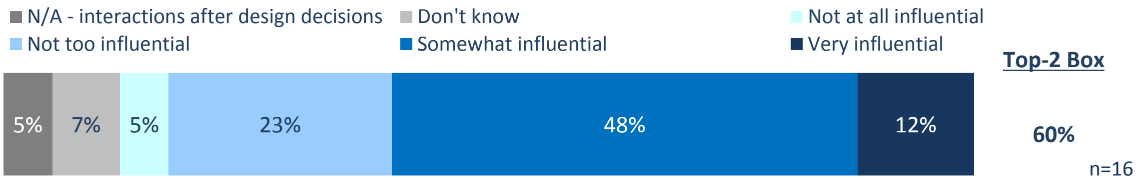
Figure 3.5. Experience with Program Resources (multiple response question)



[11] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/power-smart/builders-developers/building-envelope-thermal-bridging-guide-1.1.pdf
[12] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/power-smart/builders-developers/betbg-enhanced-spreadsheet.xlsm

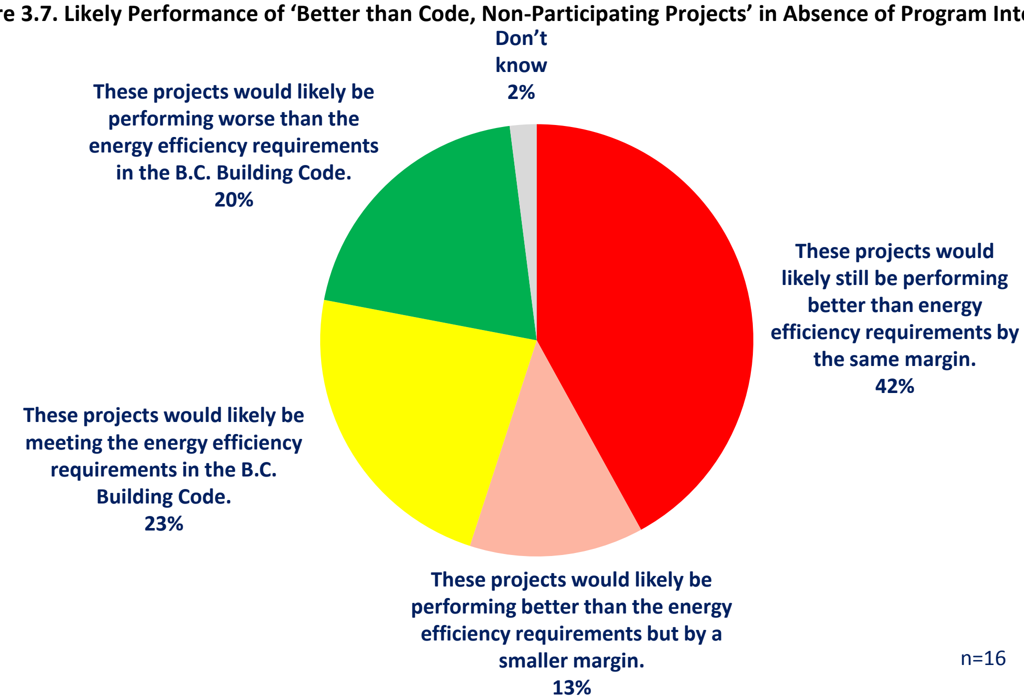
Market actors were asked to consider all of their various touchpoints with the program and the influence they had on their design decisions to have non-participating projects perform better than the building code. A total of 60 percent indicated that these program touchpoints were 'very' or 'somewhat' influential on their decisions to do so, while 28 percent indicated that the program had been 'not too influential' or 'not at all influential'. A further 7 percent did not know, while the remaining 5 percent indicated that the interaction(s) had occurred after the design decisions were made for these projects.

Figure 3.6. Influence of BC Hydro Program Interactions on Decisions to have Non-Participating Projects Perform Better than Requirements in the B.C. Building Code



Market actors were asked to think about influence from another perspective – the likely energy efficiency of their 'better than code, non-participating projects' had they not (nor any of their colleagues) had any interactions with BC Hydro's CNC program and its resources and touchpoints. While 42 percent of respondents indicated that these projects would likely still be performing better than building code energy efficiency requirements and by the same margin, a total of 56 percent indicated that these projects would likely be performing with lower energy efficiency had they not experienced these program touchpoints. This was comprised of 13 percent that felt their projects would still be performing better than the energy efficiency requirements in the B.C. Building Code but by a smaller margin, 23 percent that felt that their projects would have just met the requirements, and 20 percent that felt that their projects would likely be performing worse than the requirements. This is generally consistent with the 60 percent of respondents indicating the program had been somewhat or very influential in Figure 3.6 above.

Figure 3.7. Likely Performance of 'Better than Code, Non-Participating Projects' in Absence of Program Interactions



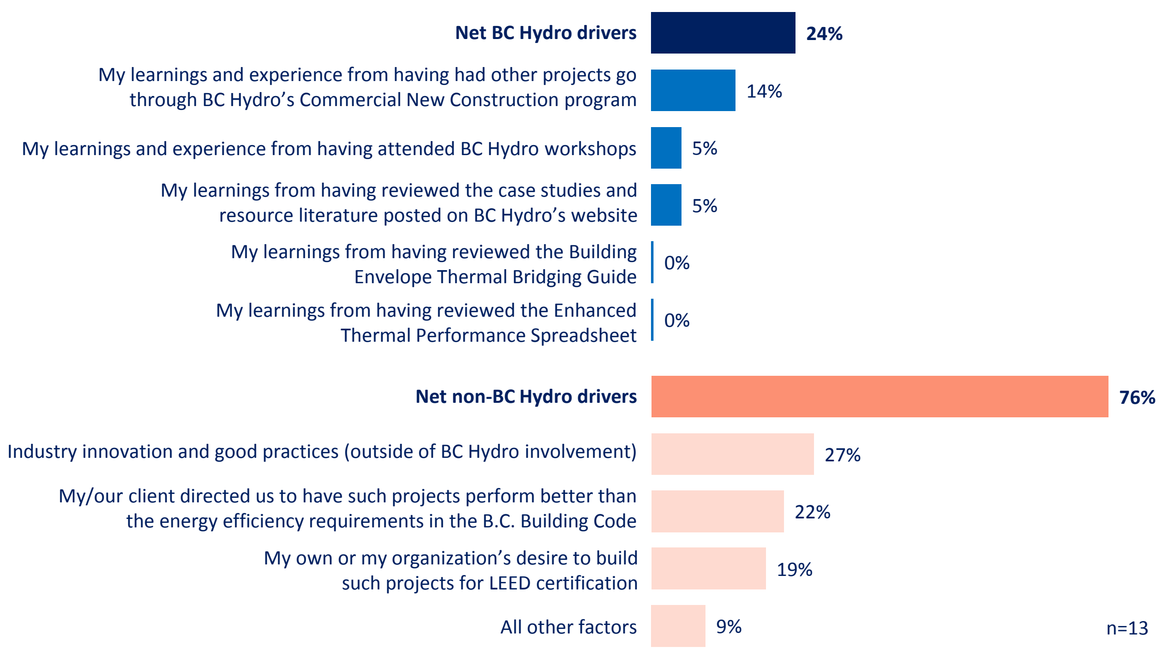
In order to understand program influence relative to other factors in the broader new construction context, market actors were asked to credit various factors for making non-program projects perform better than the B.C. Building Code, such that the factors summed to 100 percent.

Note that after excluding industry professionals who did not report any 'better than code, non-participating projects' during the evaluation period, as well as several more who were unable to provide estimates, a total of 13 respondents in the sample weighed in on this question.

On average, BC Hydro 'drivers' were given a net of 24 percent of the credit for making projects perform better than code. Specifically, previous learnings and experience with the CNC program was given the highest credit at 14 percent, followed by learnings from workshops at 5 percent and learnings from case studies/resources on the website, also at 5 percent. None explicitly gave credit to the Building Envelope Thermal Bridging Guide or to the Enhanced Thermal Performance Spreadsheet despite some respondents reporting having reviewed these resources; however, this may be due to these resources becoming available late in the evaluation period.

It follows that non-BC Hydro drivers were given 76 percent of the credit for buildings performing better than code, with the highest credit given to general industry innovation and good practices (27%) and clients directing the projects to be built as such (22%). There is a possibility that some of these non-BC Hydro factors were – to some extent – influenced by market effects ultimately tied to the Commercial New Construction Program. Should this in fact be the case, the estimate of attribution back to the program could be a conservative one as could be the overall estimate of spillover savings.

Figure 3.8. Drivers for Making Non-Participating Projects Perform Better than the Requirements in the B.C. Building Code



Another approach to assessing program influence was to query market actors on how much of the improvement in the energy use of the entire commercial new construction market in the B.C. (participant and non-participant buildings) over time could be attributed to BC Hydro's Commercial New Construction program. About half (49%) felt it was in the 20 to 30 percent range, with the most common answer at 20 percent. These results are generally consistent with findings from Figure 3.7 above on drivers where 24 percent of credit was given to BC Hydro for savings beyond code.

Table 3.6. Attribution of Savings of the Entire B.C. Commercial New Construction Market to BC Hydro's Commercial New Construction Program – For All Buildings Occupied in 2012-2016 Compared to Those Occupied in 2005 to 2011

	n=25
0% of the improved energy use in the province is attributable to BC Hydro's program	0%
1% - 9%	18%
10%	10%
20%	41%
30%	8%
40%	3%
50% + of the improved energy use in the province is attributable to BC Hydro's program	3%
Don't know	18%

Gross Electrical Energy and Peak Demand Savings

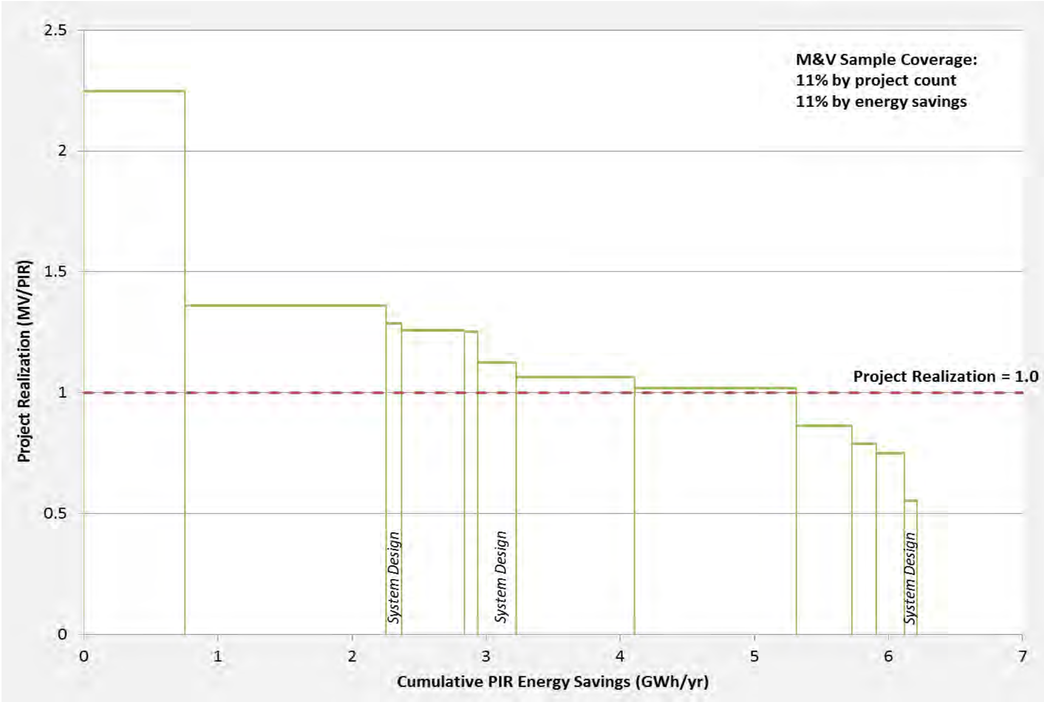
Gross electricity savings are the change in energy consumption that results directly from the program related actions taken by participants in CNC. As detailed in Section 2.3, the evaluated gross energy savings were determined through four steps (and three components of realization rate) for each of the four program offers. The four steps described were expected, inspected, verified and evaluated savings. The general approach for each step and program offer was to use a sample of projects and extrapolate to the remaining projects in the population.

Overall CNC projects involved lighting with 52 percent of the expected savings, HVAC with 37 percent, and the remaining savings distributed among building envelope improvements (5%), hot water and low-flow fixtures (2%), and refrigeration (4%) measures. The twelve projects with M&V results covered whole building design and system design projects with inclusion of interactive effects but without insight into individual measure performance by end use. Therefore, gross realization rates were evaluated by program offer.

The figure below shows the distribution of the twelve projects with M&V. Nine projects were from the Whole Building Design offer and three projects were from the System Design program offer. First, the project realizations were sorted in descending order to graphically illustrate their range and distribution. Each column in the graphs represents a single project, with the height of the column representing the project realization and the width of the column representing the project's inspected energy savings. A project realization of 1.0 indicates that the verified savings were equal to the inspected savings. The results are graphically divided into those with measure realizations above 1.0 (over performing) and below 1.0 (under performing).

The whole building design project with the highest realization rate was found to consume twice the electricity as the original model because of increased internal loads and extended hours of operation. This presented a greater opportunity for the efficient as-built HVAC systems to realize energy savings over the baseline.

Figure 3.9. M&V Results by Project Realization and Savings Size



Evaluated gross savings were analyzed to understand the breakdown by program offer between the components of realization rate. The table below summarizes the results of the components of realization rate and the overall gross realization rate by program offer. This analysis revealed that the component of realization rate for the inspected savings was between 0.89 and 0.99, whereas the component of realization rate for the verified savings was between 0.98 and 1.18. Cross effects were assumed to be embedded in the M&V results for whole building design and system design projects. An additional adjustment for cross effects was necessary for the lighting design offer and estimated at 5 percent cross effect based on the BC Hydro Standard for Cross Effects and found similar to a recent LEM-C evaluation. Of the four program offers, the whole building design offer achieved the highest gross realization rate (1.17), while the program enabled offer and the lighting design offer had the lowest realization rate (0.89).

Table 3.7. Components of Gross Realization Rate by Program Offer

Program Offer	Step 1 Expected Savings (GWh/yr)	Step 2 Factor Inspected (PIR/IR) [A]	Step 3 Factor Verified (MV/PIR) [B]	Step 4 Factor Cross Effects (CE) [C]	Gross Realization Rate [A]x[B]x[C]	Step 4 Evaluated Gross Savings (GWh/yr)
Whole Building Design	**53.4**	0.991 Calculated	1.181 Ratio Estimation	Included in M&V	**1.17**	**62.4**
Lighting Design	**29.2**	0.948 Ratio estimation	0.984 Assumed*	1-0.05 Estimated	**0.89**	**25.9**
System Design	**2.9**	0.948 Calculated	1.096 Ratio Estimation	Included in M&V	**1.04**	**3.0**
Program Enabled	**1.8**	0.887 Calculated	Not evaluated	Not evaluated	**0.89**	**1.6**
Overall CNC (F12-F16)	**87.3**	**0.973**	**1.111**	**0.014**	**1.06**	**92.9**

* Assumed from BC Hydro LEM-Commercial Impact Evaluation F2013-F2017

The following table provides the expected and evaluated gross energy and peak demand savings by fiscal year. Electricity savings are presented as incremental savings achieved within each fiscal year and expressed as an annual rate of savings (also known as run rate savings).

Table 3.8. Expected and Evaluated Gross Energy and Demand Savings All Participants (F2012-F2016)

Period	Number of Projects	Number of Measures	Expected Gross Energy Savings (GWh/yr)	Calculated Realization Rate	Evaluated Gross Energy Savings (GWh/yr)	Evaluated Gross Peak Demand Savings (MW)
F2012	47	134	9.2	1.00	9.2	1.3
F2013	60	226	18.3	1.08	19.9	2.8
F2014	58	186	23.8	1.03	24.4	3.5
F2015	67	272	17.7	1.06	18.8	2.7
F2016	52	207	18.3	1.13	20.6	3.0
CNC (F12-F16)	**284**	**1,025**	**87.3**	**1.06**	**92.9**	**13.3**

As noted above, the overall gross realization rate of the program was 1.06. This realization rate estimate is statistically valid across all projects over the five years evaluated. In order to report evaluated savings by year, as required for business purposes, annual realization rates were also calculated. These annual estimates reflect information on the types of projects reported each year, and their evaluated performance. The annual estimates do not have the statistical validity of the overall estimate, and should be treated as informative rather than conclusive. The use of annual realization rate estimates introduces some uncertainty to the annual evaluated gross savings result. An alternative approach would have been to apply the overall realization rate of 1.06 to each year evaluated. However, this approach was not taken because it would mask the year-over-year variations in participation by program offer.

Net Electrical Energy and Peak Demand Savings

Net electricity savings are the change in energy consumption attributable to the program. Net savings exclude free riders and include spillover.

Free ridership provides an estimate of the proportion of savings that were reported by the CNC program but are not attributable to it. Free ridership in this context may also be referred to as natural conservation due to market forces beyond the influence of BC Hydro.

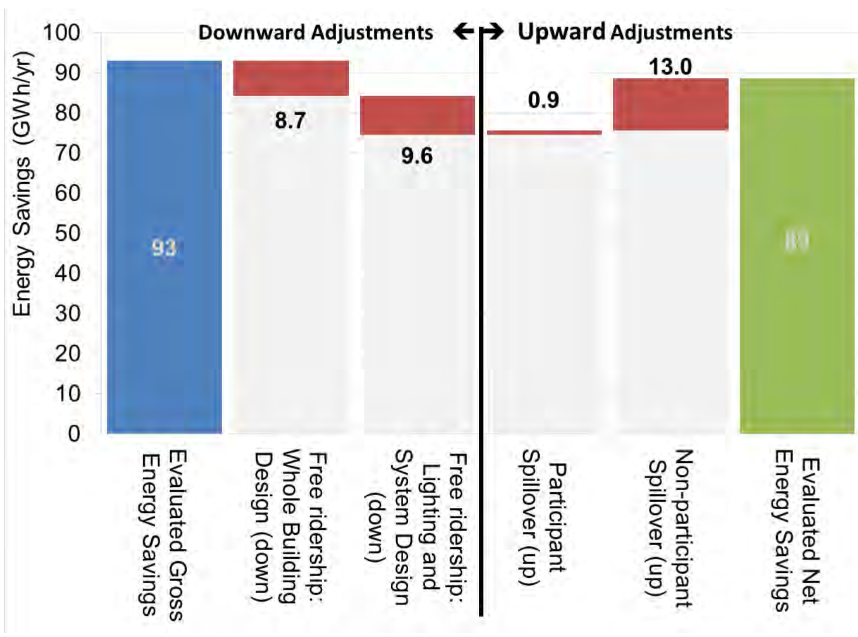
The overall level of free ridership is estimated at 20 percent for the program. Free ridership was estimated at 14 percent for whole building design and 32 percent for lighting and system design projects. Participant spillover was estimated at 1 percent and non-participant spillover was estimated at 14 percent, for a total of 15 percent. Together they result in a net-to-gross ratio of 95 percent.

Table 3.9. Free Ridership, Spillover, and Net-to-Gross Ratio

	CNC
Evaluated Gross Energy Savings (GWh/yr)	93 GWh/yr
Free Ridership (FR)	20%
Spillover (SO)	15%
Participant Spillover	*1%*
Non-Participant Spillover	*14%*
Net-to-Gross Ratio (1 – FR + SO)	**95%**
Evaluated Net Energy Savings (GWh/yr)	89 GWh/yr

The figure below illustrates both the overall effect of downward and upward adjustments to the evaluated gross energy savings from free ridership, and spillover.

Figure 3.10 Net-to-Gross Adjustments to Evaluated Gross Energy Savings



Evaluated net energy savings in each fiscal year were calculated using the evaluated gross energy savings of each project multiplied by the net-to-gross ratio of its program offer. Electricity savings are presented as incremental savings achieved within each fiscal year and expressed as an annual rate of savings. Peak demand savings were calculated using the same peak-to-energy factor as for gross demand savings. The yearly net-to-gross ratio varied slightly due to changes in the mix of projects by program offer and their respective level of energy savings. These results are summarized in the following table.

Table 3.10. Evaluated Gross and Net Energy and Peak Demand Savings

Year	Evaluated Gross Energy Savings (GWh/yr)	Evaluated Gross Peak Demand Savings (MW)	Calculated Net-to-Gross Ratio	Evaluated Net Energy Savings (GWh/yr)	Evaluated Net Peak Demand Savings (MW)
F2012	9.2	1.3	0.91	8.4	1.2
F2013	19.9	2.8	0.96	19.2	2.8
F2014	24.4	3.5	0.93	22.7	3.2
F2015	18.8	2.7	0.95	17.9	2.6
F2016	20.6	3.0	0.99	20.4	2.9
CNC (F12-F16)	**92.9**	**13.3**	**0.95**	**88.6**	**12.7**

Reported and evaluated net energy and peak demand savings for CNC are shown below. Reported savings included the results of post-implementation review and tag-on savings, where available, and were adjusted by a forecast net-to-gross ratio of 0.85. Evaluated net energy savings provide an estimate of evaluated savings that are attributable to CNC. Electricity savings are presented as incremental savings achieved within each fiscal year and expressed as an annual rate of savings (also known as run rate savings). Overall, the program achieved 121 percent of reported savings during fiscal years F2012 to F2016, showing the program performed better than reported. The variance between reported and evaluated net savings is primarily due to the impact of non-participant spillover which was estimated in the evaluation.

Table.3.11. Summary of Net Energy and Peak Demand Savings

Fiscal Year	Net Energy Savings (GWh/yr)		Net Peak Demand Savings (MW)	
	Reported	Evaluated	Reported	Evaluated
F2012	8.1	8.4	1.1	1.2
F2013	15.3	19.2	2.2	2.8
F2014	20.7	22.7	3.0	3.2
F2015	14.0	17.9	2.0	2.6
F2016	15.3	20.4	2.2	2.9
CNC (F12-F16)	**73.4**	**88.6**	**10.5**	**12.7**

Confidence and Precision

Relative precision indicates how much random error exists in an estimate derived through sampling, with lower values aligning with better precision. In impact evaluations of DSM programs and initiatives, BC Hydro targets relative precision of 20 percent or better at a confidence level of 80 percent or better.[13] For small samples, the sample to population size is weighted. If the minimum levels are not achieved, the results are considered to be inconclusive.

In the case of realization rates, relative precision provides a measure of how well the realization rate sample represents the population by savings size. As shown below, the relative precision of the three components of realization rates by program offer is 4 to 15 percent at a 90 percent confidence level, which exceeds BC Hydro's minimum target.

[13] Standard for Impact Evaluation, BC Hydro Power Smart, Conservation and Energy Management , February 2016.

Table 3.12. Confidence and Relative Precision of Gross Realization Rates

Statistical Parameter	Result for Inspected Savings in Lighting Design	Result for Verified Savings in Whole Building Design	Result for Verified Savings in System Design
Gross Realization Rate	0.95	1.18	1.10
Standard Error	0.022	0.011	0.070
Error Bound	0.036	0.182	0.116
Error Ratio	0.282	0.282	0.111
Confidence Level	90%	90%	90%
Relative Precision	**0.038**	**0.154**	**0.106**

See Table 2.3 in the methodology section for the margin of error for participant survey results.

Limitations

Limitations of the work are presented below.

1. The participant survey results for F2012 to F2014 have the potential for recall bias because the surveys were administered up to two years after the decisions that the survey queried. The magnitude and direction of any recall bias is unknown. Since F2015, the participant survey has been conducted every 6 months, mitigating the possibility for recall bias.
2. M&V coverage of whole building design and system design offers was representative by project savings size, and exceeded the target confidence and precision levels. However, the M&V coverage for lighting design projects was zero. The realization rate was assumed to be similar to the one found in the most recent evaluation of lighting projects in the BC Hydro commercial retrofit program, which introduced an unknown level of uncertainty to the evaluated gross savings.
3. Some components of the gross realization rate such as the estimation of M&V and cross effects of program enabled projects were not evaluated and add uncertainty to the results. However, the limited number of program enabled projects and the small relative magnitude of associated energy savings, compared to other program offers, limits the impact on the overall evaluated program results and did not justify further refinement of the energy savings evaluation for this program offer.
4. Demand savings could not be estimated with available data sources because project demand savings are often not reported in the program tracking data. The use of an average peak-to-energy factor based on the commercial rate class load shape for new construction sites adds uncertainty to the estimates of peak demand savings, because it relies on the assumption that the program's energy savings have the same shape as the associated load shape.
5. Due to the high cost of M&V and the lack of willing participants allowing their buildings for additional data collection and to be modelled, the evaluation lacked a representative number of M&V results which introduces uncertainty in the component of gross realization rate that it may not be representative of the population.

4.0 Findings and Recommendations

Findings and recommendations are presented below.

Findings

Participant Experience

1. Overall satisfaction was high for CNC at 80 percent, comprised of 41 percent stating they were very satisfied and 39 percent stating they were somewhat satisfied.

2. In terms of program experience, the highest scores related to aspects around service/communications from BC Hydro, as well as service provided by contractors. Mid-range scores typically related to aspects around the program offer (variety of products and level of incentives) and the overall application procedures. The lowest scores were for length of time to receive the incentive, length of time for the project to be completed and direct mail about the program.

3. Participants reported that the program had been influential on their decision to implement the energy-efficient measures, with 33 percent indicating that it had been very influential and 47 percent indicating it had been somewhat influential.

Market Transformation

4. The most common types of design study conducted to help new construction projects perform better than code were whole building design and lighting design. The most common measures implemented to help projects perform better than code were lighting and HVAC.

5. All market actors thought that there had been some improvement in the entire commercial new construction market in B.C. over the past 10 to 15 years – although not necessarily beyond code – with the majority reporting a 20 percent improvement.

Influence on Adoption of Energy Efficiency Measures Beyond Building Code Requirements

6. On average, BC Hydro 'drivers' were given a net of 24 percent of the credit for making projects perform better than code, with the largest credit given to previous learnings and experience with the CNC program. The remaining 76 percent of credit was given to non-BC Hydro drivers, with the largest given to general industry innovation/good practices and to clients directing the projects to be built as such.

Gross Electrical Energy Savings

7. The evaluated gross energy savings were 93 GWh/yr.

8. The program gross realization rate calculated using the inspected and verified results including cross effects was 1.06, indicating that the energy conservation measures largely performed better than expected. The realization rates by program offer were 1.17, 1.04, 0.89 and 0.89 for whole building design, system design, lighting design and program enabled projects, respectively.

9. Expected energy savings averaged 18 percent of site energy consumption across all participants during the five-year evaluation period.

Net Electrical Energy Savings

10. The evaluated net energy savings were 89 GWh/yr.

11. The net-to-gross ratio was 95 percent based on free ridership of 20 percent, participant spillover of 1 percent and non-participant spillover of 14 percent.

12. Evaluated net savings during the evaluation period from F2012 to F2016 averaged 121 percent of reported savings.

Recommendations

The following two recommendations are for future new construction initiatives:

1. Support and enabling activities for whole building energy modelling and integrated system approach to estimate a project's energy savings should continue and include the Building Envelope Thermal Bridging Guide and the Enhanced Thermal Performance Spreadsheet.

2. Future Market Actor surveys could be done more frequently so that respondents are better able to recall the projects they are being surveyed about.

5.0 Conclusions

BC Hydro's Commercial New Construction Program achieved high participant satisfaction. Evaluated net savings were 89 GWh/yr, which is 121 percent of reported savings. Evidence suggests that the program has supported the market in complying with and exceeding the energy efficiency requirements of the B.C. Building Code.

Evaluation Oversight Committee Sign-Off

BC Hydro's Evaluation Oversight Committee is made up of stakeholders from various parts of the company and is mandated to ensure that BC Hydro's evaluations are objective, unbiased and of sufficient quality.

The Evaluation of the [Report name here including fiscal] meets the following criteria for approval by the Evaluation Oversight Committee:

- The evaluation complied with the defined scope.
- The evaluation methodology is appropriate given the available resources at the time of the evaluation.
- The evaluation results are reasonable given the available data and resources at the time of the evaluation.

Anthea Jubb
Anthea Jubb

for Serina Grahn, Finance manager, Business Services
Evaluation Oversight Committee Chair

January 23, 2020
Date

References

Abbreviations and Glossary

Baseline:	A baseline is the initial condition occurring when a DSM activity begins. It may be a market share for equipment, a current standard (e.g., building code), or a current average behavior.
Cross Effects:	Cross effects (also known as interactive effects) refer to the effect that some energy conservation measures (ECMs) have on other electricity end uses beyond what the ECM itself produces. An obvious example is building lighting. As more efficient lighting is installed, less heat is generated by the lighting system. This means that less heat must be removed from the building by the air conditioning system during the cooling season, but more heat needs to be supplied by the heating system during the heating season.
Demand Side Management (DSM):	"a rate, measure, action or program undertaken; (a) to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand, but does not include (d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or (e) any rate, measure, action or program prescribed". (*Clean Energy Act, s. 1*)
Expected Savings:	Estimate of gross energy savings based on the initial engineering estimates. These estimates represent the unverified savings.
Evaluated Savings:	Savings estimates reported after the energy efficiency activities have been implemented and an impact evaluation has been completed.
Free ridership:	Energy use of a program participant or ratepayer under a conservation rate who would have implemented the program conservation measure or practice in the absence of the program or rate.
Gigawatt Hour (GWh):	One billion watt-hours; one million kilowatt-hours.
Gross Savings:	The change in energy consumption and/or demand that results directly from program-related action taken by the participants in the demand side management program irrespective of why they participated.
Market Transformation:	Market Transformation refers to a permanent change in the structure or functioning of markets, including more energy efficient behaviour among customers and higher market penetration of energy-efficient products, as a result of demand-side management (DSM) programs that reduce barriers to energy efficiency. These market changes are likely to persist in the absence of continued program activity. The reference case is used to establish the level of market transformation over time.
Natural Conservation:	Natural conservation refers to those efficiency improvements that would occur in the absence of any DSM activity. This may be due to equipment efficiencies, behaviors, changes to codes and standards or simply reactions to general rate increases.
Net savings:	The change in energy consumption and/or demand that is attributable to the utility demand side management program. The change in consumption or demand may include the effects of free riders and spillover.

Net-to-Gross Ratio: The combination of free rider and spillover estimates which are then applied to the gross savings to provide an estimate of attributable net savings for the program. Reflects program influence, does not reflect project performance in terms of energy savings estimated or measured.

Peak-to-Energy Factor: Relates to BC Hydro's system peak demand in MW, to annual energy consumption, in GWh based on the load shape of a given sector.

Realization Rate: The ratio of initial estimates of savings to savings adjusted for data errors and M&V results. Realization rate does not reflect program attribution or influence on the savings achieved.

Reported Savings: Estimate of energy savings being recorded in the program tracking database. Reported savings are based on best information available from technical review of the initial engineering estimate, post-implementation review of documentation and/or inspection, or measurement and verification results, as well as a forecast net-to-gross ratio.

Spillover: Refers to program participants and non-participants whose energy savings measures occur through actions that are not part of a program, but which were influenced by the program (also called free drivers or tag-ons). Participant spillover is the additional energy savings that occur when a program participant independently installs energy efficiency measures or applies energy savings practices after having participated in the efficiency program, as a result of the program's influence. Non-participant spillover refers to energy savings that occur when a program non-participant installs energy efficiency measures or applies energy savings practices as a result of a program's influence. Spillover may not be permanent and may not continue in the absence of continued program activity.

Appendix A Results Summary

The purpose of this appendix is to summarize key numerical results from the CNC program evaluation for the period of F2012 to F2016. The following table present the savings summary.

Table A.1. Summary of Net Energy and Peak Demand Savings

	Net Energy Savings (GWh/yr)		Net Peak Demand Savings (MW)	
Fiscal Year	**Reported**	**Evaluated**	**Reported**	**Evaluated**
F2012	8.1	8.4	1.1	1.2
F2013	15.3	19.2	2.2	2.8
F2014	20.7	22.7	3.0	3.2
F2015	14.0	17.9	2.0	2.6
F2016	15.3	20.4	2.2	2.9
CNC (F12-F16)	**73.4**	**88.6**	**10.5**	**12.7**

Table A.2. Key Results of the CNC Program Evaluation F2012-F2016

Estimate	Result
Realization rate (evaluated gross as % of expected savings)	106%
Cross effects (calculated as % of expected savings of Lighting Design offer) To the extent they occurred, cross effects are included in evaluated gross savings for Whole Building Design and System Design program offers.	5%
Net-to-gross ratio (calculated as % of evaluated gross; excluding cross effects)	95%
Free ridership (calculated as % of evaluated gross)	20%
Participant spillover (calculated as % of evaluated gross)	1%
Non-participant spillover (calculated as % of evaluated gross)	14%
Rebound (% of evaluated gross)	Not required[1]
Peak-to-Energy Factor (MW/GWh)	0.143 MW/GWh
Weighted average persistence of program savings	15 years
Variance Factor (evaluated net as % of reported savings)	121%

[1] BC Hydro Standard for Rebound Effects (2011)

Appendix B Advisor Memos on Evaluation Report

January 24, 2020

To: BC Hydro
333 Dunsmuir St.
Vancouver, B.C.
V6B 5R3

From: Pierre Baillargeon
Evaluation Advisor
Vice President Econoler
160 Saint-Paul St., Suite 200
Quebec City, QC GIK 3W1

Re: Evaluation of the Commercial New Construction (CNC) Program: F2012-F2016

Dear Madam or Sir:

This advisory memo summarizes the opinions of the evaluation advisor on the evaluation work performed by the BC Hydro evaluation team for the abovementioned program. It takes into consideration the comments and answers from and exchanges with the evaluation team, which were incorporated into the final version of the evaluation report.

Overall appreciation of the report:

- Excellent quality in general. The report is easy to read and flows well. It clearly demonstrates the important impact of the initiative on the market, as well as the high participant satisfaction and high realization rate achieved.
- The advisor commends the evaluation team for the openness and transparency during the whole review process. Exchanges with the BC Hydro team were excellent. They provided clear and precise answers to all questions and additional information whenever necessary.

1. What is your assessment of the quality of the research design? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?
   - The quality of the research design is excellent and appropriate for a new construction program.
     - The program and how it operates to transform the market is well described;
     - The logic model clearly summarizes the program components, outputs, outcomes (short, intermediate and long-term objectives);
     - The evaluation objectives and research questions are clear.
2. What is your assessment of the quality of the input data? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?

- The advisor notes the significant effort that went into determining the savings of nine sites using Option D (calibrated simulation) of the International Performance Monitoring and Verification Protocol (IPMVP). While the sample is relatively small, this approach is complex and time consuming, which justify limiting the number of sites with calibrated simulation.
- The projects without full measurement and verification (M&V) went through an initial review of the expected savings; then a significant share of participants went through an additional post-implementation review. This is an appropriate approach for this type of program.
- The advisor expressed some concern about the small number of market actors that were interviewed to determine non-participant spillover. However, the report clearly states the limitation associated with this low number of respondents. Moreover, the advisor recognizes that market actor interviews to determine market trends and non-participant probable courses of action are always a difficult endeavour.

3. What is your assessment of the quality of the analytical methods? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?
   - The analytical method was good and appropriate for the type of evaluation conducted. The portion of participants evaluated through M&V are in line with international best practices for program evaluation. The lighting component of the program relies on initial and post-installation reviews and is acceptable since lighting is a less complex measure to evaluate.
   - The spillover calculations have some uncertainty due to the low number of respondents and a relatively complex questionnaire. The threat to validity and these limitations are well identified and discussed in the report.
4. How does the methodology compare to common industry practice for evaluations of similar initiatives?
   - The methodologies are in line with best evaluation practices. The report properly covers the review of literature for similar programs and identifies and applies recommendations from the Uniform Methods Project (UMP).
5. What are your suggestions for future evaluations of this DSM initiative?
   - The advisor is in agreement with the main recommendations for future evaluations included in the report by the BC evaluation team.
6. Do you have any other comments that you would like to make?
   - No, this evaluation effort is well done.

January 28, 2020

To: BC Hydro

333 Dunsmuir St.

Vancouver, B.C.

V6B 5R3

From: Rafael Friedmann

Evaluation Advisor

Oakland, California

Re: Evaluation of the Commercial New Construction (CNC) Program: F2012-F2016

1. What is your assessment of the quality of the research design? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?
    - The effort is appropriate to the research goals. Good description of both goals and CNC program. Good integration of a variety of information, both primary and secondary, to obtain a good understanding of changes in this varied customer segment and impact of BC Hydro's comprehensive mix of CNC offerings.

2. What is the assessment of the quality of the input data? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?
    - Data is drawn from a comprehensive and appropriate mix of program tracking data, M&V of specific projects, secondary data, and surveys of participants and market actors. Limited number of survey responses at times could affect the validity of results depending on how representative these are of the broader population. Data for M&V of specific projects very good. Data used for free ridership and spillover/market effects limited and more uncertain.

3. What is your assessment of the quality of the analytical methods? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluated results?
    - Market actor surveys provide insights on market changes and impacts to building codes. Methods for estimating gross savings draw from specific projects M&V based on IPMVP and UMP. Free ridership and Spillover (participant and non-participant) use surveys similar to those used in other BC Hydro evaluations and by other jurisdictions. All these methods are sound as long as respondents are a good representation of the broader population.

4. How does the methodology compare to common industry practice for evaluations of similar initiatives?
    - Methods used align well with those used elsewhere to address the evaluation questions. BC Hydro's efforts to estimate non-participant spillover go beyond usual practice and provide a better understanding of the CNC offerings impact.

5. What are your suggestions for future evaluations of this DSM initiative?
    - The CNC program is being phased out by 2022 and no more evaluations are being considered. Lessons from this evaluation that provide useful insights to consider in other similar evaluations include: 1) Study more why non-participants are not engaging with the program; 2) Consider doing

some sensitivity analyses on savings estimates; 3) Conduct ongoing market actor and participant satisfaction surveys soon after participation; 4) Examine more deeply spillover (participant & non-participant) to improve our understanding of how to foster it and also reduce the uncertainty in its savings estimates.

6. Do you have any other comments that you would like to make?
   - Well written, easy to follow report for a quite complex mix of program offerings to a varied customer base, over a long time period. Appreciate the added language in the final report on threats to validity and uncertainty in the results.

Appendix C Approach Details

C.1. Additional Details on the Participant Survey

Surveys were used as the main source of information for evaluation objective 1 (customer experience) and as a key input for objective 5 (net savings). An online survey of program participants and non-participants was employed, with the following main steps listed below.

An online methodology was selected for this survey for a number of reasons: 1) email addresses were available for the full participant population; 2) the online format better allowed for presenting detailed information on projects completed under the program (e.g., service address, types of upgrades completed, etc.) compared to most other methodologies; 3) the length and complexity of the survey was better suited to a format where the respondent could take the time to make well-considered responses and/or obtain information from others involved in the project; and 4) an online methodology was more cost-effective to collect large sample sizes as compared to telephone surveys.

- Draft survey instruments were prepared, reviewed with program stakeholders and revised to include additional questions of interest.
- The participant sample was developed to include all available CNC program participants. The sample excluded any contacts who had been surveyed within the past six months for any other BC Hydro survey (as per BC Hydro policy on customer contacts). The invitation email included text that asked respondents to forward the survey link to an individual who, in that person's opinion, may have more knowledge about their organization's participation in the program.
- The surveys were programmed in an online format and tested for ease of use and proper functionality.
- The participant surveys were fielded in:
    - May 2013 (for projects completed in F2012)
    - July/August 2014 (for projects completed in F2013 to F2014)
    - November 2014 (for projects completed in the first half of F2015)
    - May 2015 (for projects completed in the second half of F2015)
    - November 2015 (for projects completed in the first half of F2016)
    - May 2016 (for projects completed in the second half of F2016)
- Participants received an honorarium of a $50 gift card for completion of their survey. Multiple reminders were sent to increase the response rate.
- Data were cleaned and cross tabulations were prepared for the evaluation period.

To ensure that survey respondents had the appropriate level of decision making authority for the purpose of this study, a number of questions were asked to determine key characteristics of the respondent and of their facility. The tables below provide customer responses about their title/position within the company as well as decision making responsibilities.

Table C.1. Position/Title of Respondent

Position or Title	CNC Participants (n=57)
Project Manager	34%
Developer	16%
General manager	9%
Business owner or co-owner	8%
Energy Manager – hired as part of BC Hydro's PSP/Energy Manager Program	7%
Executive	6%
Energy Manager - unspecified if BCH funded (response option from prior to 2013)	6%
Site or property manager/supervisor	4%
Energy Manager – NOT hired as part of BC Hydro's PSP/Energy Manager Program	3%
Accountant/Bookkeeper	1%
Finance manager	1%
Other	6%
Total	100%

Table C.2. Primary or Joint Decision Maker (% yes)

Responsible for decisions related to…	CNC Participants (n=57)
Energy management	59%
Investments in equipment costing less than $100,000	58%
Investments in equipment costing $100,000+	51%
Capital investments in retrofitting existing sites/facilities or building new sites/facilities	37%
The operation and maintenance of sites/facilities	36%
The maintenance of equipment	31%

C.2. Additional Details on the Market Actors Survey

For many of the same reasons given in regards to the participant survey, the Market Actors Survey was conducted online. In the same way, the Market Actors Survey was designed by Evaluation staff, and reviewed and revised based on stakeholder feedback. Subsequent to that, the survey was programmed in the online format and tested in a first round by internal staff for its desired functionality, and tested in a second round by five external industry contacts to ensure the questions were meaningful, well-understood and unambiguous.

As already explained earlier in this report, industry professionals for this survey were targeted and sourced via two methods. In the first method, survey invitations were directly emailed to approximately 300 industry professionals for which business contact information (i.e., email addresses) was known. In the second method, an invitation to participate in this research was indirectly made by embedding communications into various industry association e-newsletters and online bulletin boards. These associations included:

- International Building Performance Simulation Association;
- Illuminating Engineering Society of BC;
- ASHRAE BC: American Society of Heating, Refrigerating and Air conditioning Engineers; and
- Architectural Institute of British Columbia.

A total of 30 eligible professionals completed the survey. In doing so, they considered and responded to lines of questions about energy efficiency design and decision making in British Columbia's commercial new construction industry in its broadest context, and also in regards to their own projects in a much narrower context. In this regard, they were funneled through an iteration of questions and grids that converged to be specifically about any of their projects that were designed to perform better than the B.C. Building Code, but did not come through BC Hydro's program. As illustrated in the survey document, this approach was conducted for each of the five years – concurrently – 2012 through to 2016. Note that the sample size decreased to 13-15 through some of these questions due to the fact that not all 30 respondents had 'better than code, non-participating projects' in these particular years.

Based on the input of experts who advised on this evaluation, the data was statistically weighted by the role of the industry professional, reflecting the fact that certain professions – their design roles and decisions – have a greater influence than others in the extent that a project is to be energy efficient. Specifically, three groups of respondents – electrical engineers, mechanical engineers, and energy modelers – were each assigned a 30 percent weighting in their opinions on any given question. All other respondents with other occupational roles in the design and decision process were collectively assigned the 10 percent balance of weight.

Table C.3 below details the role of the industry professionals in the survey sample before statistical weighting.

Table C.3. Role of Industry Professional

	Industry Professionals (n=30)
I was often a key decision maker regarding the extent that projects would be energy efficient	40%
I typically was not a key decision maker, but did provide inputs, alternate options and/or my opinions into the decision making process	60%
I typically had little or no role in the decision making process	0%

Percents are unweighted data.

Table C.4 below details the occupational title or role of the industry professionals in the survey sample before statistical weighting.

Table C.4. Position/Title of Industry Professional

	Industry Professionals (n=30)
Mechanical engineer	53%
Electrical engineer	17%
Energy modeller	17%
Project management	17%
Architect	13%
Real estate	7%
Specifications writer	7%
Project developer/development	3%
Other	20%

Percents are unweighted data.
Other is comprised of the following: Building Code / Fire Engineers; Energy Advisor; Facility Management; Mechanical Designer; Set energy performance standards; Turnkey system provider.

C.3: Additional Details on the Free Rider and Spillover Analysis

Free Ridership

The algorithm used to assign free rider scores for the decision maker survey is shown in the free rider decision tree (see below). For each organization, a free rider score was assigned according to the organization's answers to the survey questions shown in the decision tree. Free rider scores vary between 0.0 and 1.0; where a score of 1.0 represents a full free rider, a score of 0.0 represents a full non-free rider, and a score between 0.0 and 1.0 represents a partial free rider. An example of a full free rider would be an incentive project where the organization indicated that it would have completed the project on its own, at the same efficiency level and scale, even without the assistance of the program, and it was not at all influenced by the program, nor required program assistance to have met any financial criteria. An example of a partial free rider would be an incentive project where an organization indicated that it would have completed it on its own but at a lower efficiency level. An example of a full non-free rider would be a project that would not have been completed at all without the assistance of the CNC program. Spillover was estimated using a similar approach.

There were seven self-report parameters used to inform the free rider algorithm. The rationale for the various pathways and deductions that are shown within the free rider decision tree are described below.

a. Action the organization would have taken if the program had not existed (Steps 1 to 5)

- If the organization indicated that it DID NOT KNOW whether it would have completed the project in absence of the program (Step 2), the final free rider score depended on the organization's answer to the 'influence' question (Step 3). The answers to the influence question range from 0.0 to 1.0 with increments of 0.25, and 'don't know' scoring 0.5. These scores help differentiate between responses and permit the assignment of free rider scores (e.g., 'very influential' was assigned a lower free rider score than a 'somewhat influential' response; 0.0 versus 0.25, respectively).
- If the organization indicated that it WOULD NOT HAVE completed the energy efficiency project in absence of the program, it was assigned a final free rider score of 0.0 (Step 4). Organizations were not queried further because 'not completing a project' represented the path of least resistance from a planning perspective. No attempt was made to further 'test' their intentions, nor were they asked about program influence (an assumption was made that they would have answered that the program had been 'very influential').
- If the organization indicated it WOULD have implemented the energy efficient measures, it was assigned an initial free rider score of 1.0 (Step 5). Deductions to this score were then applied to reflect prior plans, efficiency and scale of the project had they completed it on their own (Steps 6 to 13). The algorithm 'chips away' their stated intention and their initial free rider score of 1.0 by considering their responses to these additional questions.

b. Prior plans to install energy efficient measures/technologies before becoming aware of the program (Steps 6 to 8)

- If the organization WOULD have implemented the energy efficient measures and had plans to do so BEFORE becoming aware of the program, no deductions were made to the free rider score in this step (Step 7). This group was not asked the influence question as their plans had been made before any interaction with the program. As such, it was assumed the program would have been 'not at all influential' on their basic plans to carry out some sort of upgrades.
- If the organization WOULD have implemented the energy efficient measure, but had made plans only AFTER the idea was first suggested by a BC Hydro-funded energy consultant, a BC Hydro-funded

Energy Manager or a BC Hydro representative (Step 8), the organization was then asked how influential the program was on the decision to implement the measure.

c. Influence of the program on the decision to install energy efficient measures/technologies (Step 9)

- For those organizations that made plans AFTER suggestion from BC Hydro, influence was taken into account to reflect the possibility of a causal relationship between 2nd or 3rd party 'suggestion' and the decision to implement the energy efficient measures. The rationale for utilizing the 'influence' question at this stage of the algorithm was that a suggestion could take many different forms, ranging anywhere from a simple verbal suggestion during a meeting, to an energy study. Based on professional judgment, points were deducted from the free rider score to reflect the fact that we were no longer 100% sure that the organization would have installed the measure in absence of the program:0.5 for VERY INFLUENTIAL, 0.35 for SOMEWHAT INFLUENTIAL, 0.15 for NOT TOO INFLUENTIAL, 0 for NOT AT ALL INFLUENTIAL and 0.25 for don't know responses The assumption was that the program was at least partially influential on the organization's decision to do so.

d. Financial criteria around site investment (Step 10)

- For incentive projects, if an organization indicated that its energy efficiency project would NOT have met their organization's financial criteria for site investments without assistance from the program, then the free rider score was reduced by an additional 0.5. Although for-profit businesses rely heavily on the financial bottom line, a project can still proceed even if it does not meet an organization's financial criteria due to other non-financial factors such as anticipated change of regulations, safety, market prices, etc. This suggests that a project can still be a partial free rider even if it requires an incentive payment from the program to meet the organization's financial criteria. If the organization believed their financial criteria would have been met, the free rider score was not adjusted. If the organization did not know, the free rider score was reduced by 0.25.

e. Energy efficiency level of new measures/technologies in absence of the program (Step 11)

- If an organization indicated that the energy efficiency of the project would have been AS EFFICIENT or MORE EFFICIENT in absence of the program, no points were deducted.
- A deduction of 1.0 was made if the organization would have completed a LESS ENERGY EFFICIENT project in absence of the program. For CNC, baselines are determined through BC Hydro Conservation & Energy Management Engineering review. In cases where several different options are available to the customer that range in efficiency, Engineering calculates gross energy savings using a baseline of what the customer would have likely done without the influence of the program. In other words, only savings that go beyond common market practice (natural conservation) are claimed by the program. Therefore, a participant who reports that they would have done something less efficient in the absence of the program is a 0 percent free rider on this specific aspect of free ridership (i.e., a 1.0 deduction).
- A deduction of 0.5 was made if the organization DID NOT KNOW what level of energy efficiency the project would have had. This value was used to maintain the average deduction between those organizations which would have implemented a measure with the same or higher efficiency and those organizations which would have implemented a measure with less efficiency.

g. Percent of the project that would have been completed in absence of the program (Step 12)

- A final adjustment to the free rider score was made based on the percentage of the project that would have been completed if no assistance had been provided through the program, e.g., if 40 percent of the project would have been completed in absence of the program, the free rider score was multiplied by 0.4. 'Don't know' response did not receive any adjustments, i.e., they were multiplied by 1.

h. Timing

- Note that while timing of the project was explored in the survey, it was excluded from the algorithm due to the nature of CNC projects. Due to the high cost and long lifespan of the types of projects CNC pertains to, if a particular energy efficient technology is not installed as part of the initial construction, it is unlikely that it would be brought in to replace a less efficient technology in the short to medium term. It would not be financially feasible to replace a recently installed technology with a more energy efficient one – it is either included as part of initial construction or not replaced again until the long term.

- After applying all of the adjustments, an individual free rider score was calculated for each site that responded to the survey. These scores were then weighted by savings and averaged to calculate a grand mean free rider score.

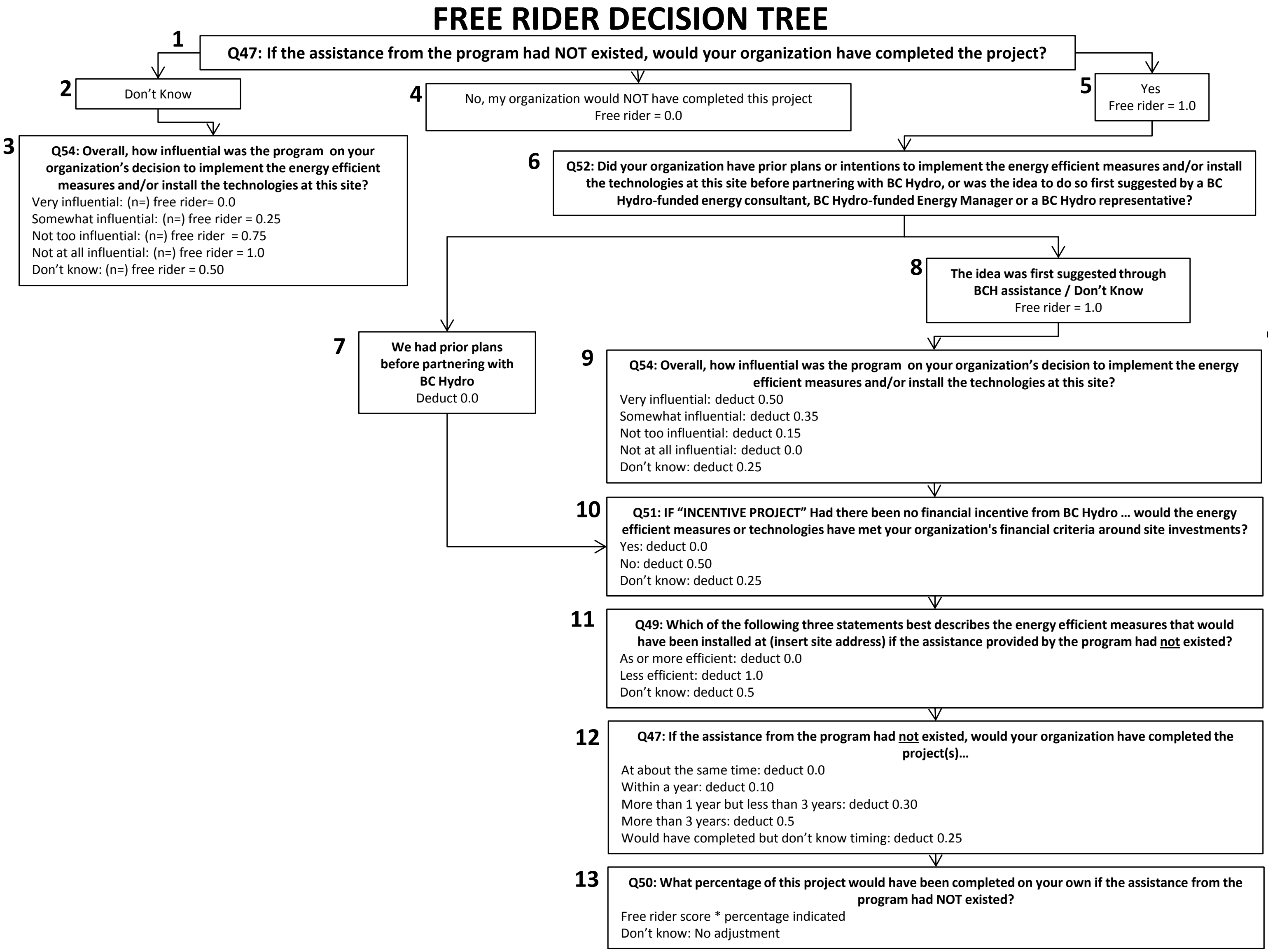


Figure C.1. Free Rider Decision Tree

Participant Spillover

The participant spillover decision tree logic is presented as Figure C.2. The rationale for the various pathways and additions on the spillover decision tree are described below. All organizations were initially assigned a spillover score of 0.0. Spillover points were then *added* – thereby crediting the program with additional savings – depending on responses a series of questions.

a. Additional energy efficient projects completed without assistance from CNC (Steps 1-4)

- Organizations that DID NOT KNOW whether any new energy efficiency projects were undertaken at a specified site were given a final spillover score of 0.0. This is because the program cannot claim additional savings for something that may or may not have been completed (Step 2).
- Organizations that indicated that NO additional energy efficiency projects had been undertaken were given a final spillover score of 0.0. A score of 0.0 indicated that no additional savings could be claimed by the program for this site and they were excluded from further analysis (Step 3).
- Organizations that indicated that additional energy efficiency projects HAD BEEN IMPLEMENTED without assistance from the program were asked to select the ones they installed from a list of common end-uses and technologies (e.g., lighting, cooling systems, heating systems, water heating, etc.). From this point forward, each end-use or technology that was upgraded was analyzed separately in order to assign a spillover score at a retrofit level.

b. Funding from other organizations (Steps 5 to 7)

- Projects that received assistance from a program offered by another organization were assigned a final spillover score of 0.0 (Step 6). While it was possible that the CNC program could have influenced these particular projects, these projects were removed from further analysis as it was not possible to reliably separate the level of influence from the different overlapping programs. This removal resulted in a more conservative spillover estimate.
- If no other funding was received, no credits were added, but the organization continued with additional questions.

c. Action the organization would have taken if the program had not existed (Steps 8 to 11)

- Energy-efficient retrofits or upgrades made without the assistance of another organization were then grouped using the ‘timing’ question. Those projects that would have NOT been completed at all if the organization had not participated in the program were giving a final spillover score of 1.0, fully crediting the program for the spillover savings associated with these projects.
- Those projects that would have gone ahead regardless of program participation continued with questioning regarding prior plans, influence, timing, efficiency and scale of the project. If the organization was unsure about whether the project would have been completed in absence of the program, it was also asked these additional questions – a more conservative approach – rather than being assigned any spillover additions at this point.

d. Prior plans and influence of the program on the decision to install additional energy efficient measures/ technologies (Steps 12 to 15)

- If an organization first had plans to implement the measure PRIOR to its participation in the program, it was not asked the influence question (Step 12). It was assumed that the influence would have been ‘not at all’ since their plans were in place before any interaction with the program.

- If the organization first made plans AFTER its participation in the program, it was asked how influential the program was on its decision to complete these additional projects. The spillover score at this step ranges from 0.0 to 1.0.

e. Timing of installing the additional energy efficiency measures/technologies in absence of the program (Step 16)

- If an organization would have completed the project AT THE SAME TIME or WITHIN A YEAR of when it was actually done, no credits were added to the spillover score. Also, no credits were added if the organization would have completed the project, but was unsure about the timing.
- For those organizations that would have completed the project, a credit of 0.1 was added for MORE THAN ONE YEAR BUT LESS THAN 3 YEARS and 0.3 was added for MORE THAN 3 YEARS. The higher credits for the projects originally planned further in the future reflects bringing those projects – and the associated savings – forward in time by a greater number of years. Similar to the free rider influence question, the credits are heuristics that help differentiate between responses and permit the assignment of spillover scores.

f. Energy efficiency level of the additional measures/technologies in absence of the program (Step 17)

- If the project would have been LESS ENERGY EFFICIENT had the organization not participated in the program, a credit of 0.5 was added to the spillover score.
- However, if the project would have been AS EFFICIENT or MORE EFFICIENT, no credits were added since the program interaction did not result in any additional savings beyond the organization's original plans. No credits were added for 'don't know' responses.

g. Amount or number of additional energy efficient measures/technologies that would have been completed in absence of the program (Step 18)

- If the organization originally intended to implement FEWER energy efficient measures prior to participating in/becoming aware of the program, the program was credited with the additional savings associated with the increased scale of the project through an addition of 0.25 points.
- If the SAME or MORE measures were originally planned, no credits were added to the spillover score.

In order to convert the spillover score into the same metric as the free rider score, a typical savings estimate was applied to each individual end-use that was upgraded, and then those savings were adjusted by the organization's final spillover score for that particular end-use. The adjusted spillover savings for each individual end-use for each organization were summed and then used to calculate an average spillover savings per site (including those sites that reported no spillover activity). This average was then used to extrapolate spillover savings to the entire participant population. Finally, the total spillover savings were expressed as a percentage of the total evaluated gross program savings.

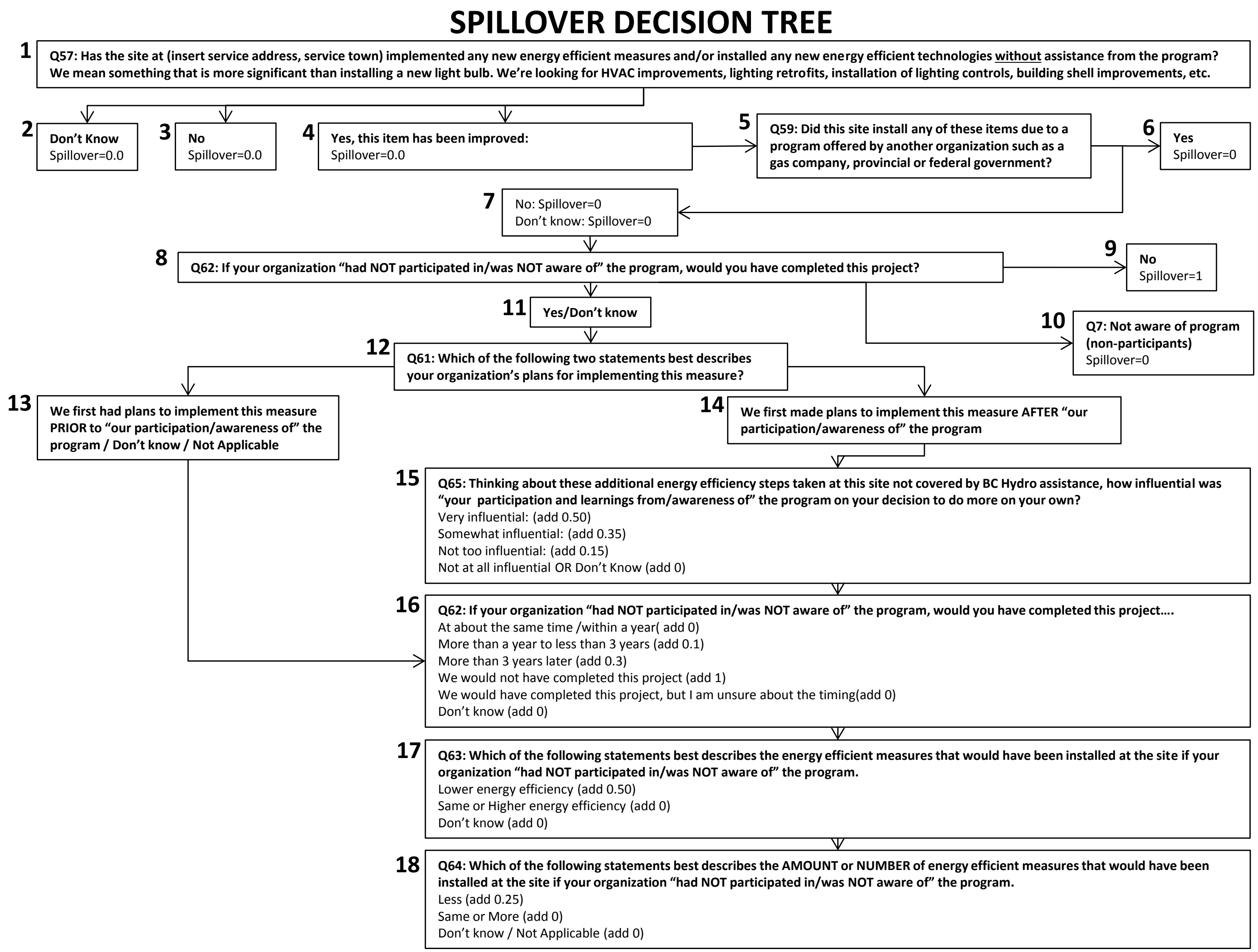


Figure C.2. Participant Spillover Decision Tree

Non-Participant Spillover

As already outlined in Section 2 and presented again in Table C.5 below, non-participant spillover pertaining to the entire five year evaluation period of interest was estimated via a calculation involving five inputs. The calculations of inputs D, E and F are further explained below.

Table C.5

A.	Commercial new construction building stock in B.C. that could have been influenced by the program F12-F16 (m^2)	A
B.	Commercial new construction building stock that did receive BC Hydro program funding F12-F16 (m^2)	B
C.	Commercial new construction building stock that did <u>not</u> receive BC Hydro program funding F12-F16 (m^2)	C = A – B
D.	Percent of commercial new construction building stock that exceeds code F12-F16 (%)	D
E.	For commercial new construction building stock that exceeds the B.C. Building Code, the average unit electricity savings relative to the code (kWh/m^2)	E
F.	Attribution of electricity savings to BC Hydro's Commercial New Construction Program (%)	F
G.	Non-Participant Spillover F12-F16 (GWh)	$G = \frac{C \times D \times E \times F}{1{,}000{,}000}$

Details of Input D: Percent of commercial new construction building stock that exceeds code

Findings from the Market Actors Survey were used to estimate the percent of commercial new construction floor area during the evaluation period that exceeded the B.C. Building Code (row D).

As this estimate was applied to the commercial new construction projects that did not receive program funding in the pursuit of non-participant spillover, it was ultimately based on survey respondents' non-participating projects. However, this estimate of the percent of commercial new construction floor area that exceeded code could only be distilled after respondents were taken through questions about all of their projects – some of which were in fact participating projects. As explained further below, such estimates that were later determined to include participating projects were excluded from further calculations.

Lines of questions in the survey solicited – for each of the five years 2012 through to 2016 – a respondent's total amount of commercial new construction floor area that they worked on and, through further calculation, the total amount of floor area that was designed and built to perform better than the energy efficiency requirement in the B.C. Building Code. The questions pertaining to each year were presented concurrently in a grid format.

For each year, a respondent then disaggregated their 'better than code' floor area – if there was any – into the amount that received program funding and the amount did <u>not</u> receive BC Hydro program funding[14].

[14] An alternate approach would have been to first ask survey respondents to estimate the total amount of their commercial new construction floor area that did not receive program funding, then to estimate the amount of that non-participating floor area that was designed and built to perform better than the B.C. Building Code. However, it was believed that this sequence of questioning and deduction would be less intuitive for most respondents.

For each year in which a respondent did not have any projects at all that received program funding, the percent of their commercial new construction floor area that exceeded the energy efficiency requirement in the B.C. Building Code was calculated as the total amount of their floor area in that year that exceeded the code divided by the total amount of floor area that they had worked on. Conversely, for any year in which a respondent did have at least some of their 'better than code' projects receive program funding, the estimate of the percent 'better than code' – intended to be applied strictly to non-participating projects for that year – was subsequently discarded. This was because for any given year, a respondent's 'better than code' floor area that did not receive program funding could not be disentangled from their 'better than code' floor area that did receive funding.

For each year, an average percent of commercial new construction floor area that exceeded code was then calculated as the average percent among all eligible respondents – weighted by the total built floor area that any one respondent had worked on.

Covering the entire five years of this evaluation period, the grand average of the percent of commercial new construction floor area that exceeded code was then calculated as the average percent from each individual year – weighted by the combined total built floor area for all respondents in each year.

Details of Input E: Average unit electricity savings for new construction building stock that exceeds code

Findings from the survey – together with end-use intensity data from BC Hydro's 2016 Conservation Potential Review (CPR) – were used to estimate average unit electricity savings for the floor area that exceed the B.C. Building Code (row E) over the five year evaluation period.

Survey respondents who reported having had commercial new construction projects over the five years that were designed to perform better than the B.C. Building Code and that did not receive BC Hydro program funding were asked a series of questions about their 'better than code, non-participating' projects.

These respondents were first asked to indicate which one(s) of eight different energy-efficient measures they at least sometimes designed or recommended to be implemented in their 'better than code, non-participating' projects.

Next, for each measure that was at least sometimes implemented, respondents were then asked to 1) estimate the percentage of their 'better than code, non-participating' floor area over the five years that either incorporated or benefitted from the measure, and 2) estimate the percent electricity savings from the measure as compared to a conventional measure that could have been implemented to just meet – not exceed – the energy efficiency requirements in the B.C. Building Code.

This information was then integrated with end-use intensity data from BC Hydro's 2016 Conservation Potential Review (CPR) to yield an estimate of the average unit electricity savings (kWh/m^2) – relative to the building code – for these 'better than code, non-participating' projects.

Details of Input F: Attribution of savings to BC Hydro's Commercial New Construction Program

Findings from the survey were used to estimate the attribution of gross electricity savings from 'better than code, non-participating' commercial new construction projects over the five year evaluation period back to the Commercial New Construction Program (row F).

Survey respondents were asked to reflect upon their new construction projects in B.C. – those that became occupied from 2012 to 2016 – that are performing better than the energy efficiency requirements in the B.C. Building Code and that did not receive BC Hydro program funding.

In doing so, they were asked to assess each of nine different factors in terms of the factors' influence on making these particular projects perform 'better than code'. As detailed on the following page, five of these factors were tied to BC Hydro's Commercial New Construction Program, its complementary offerings and the industry resources for which it played an integral role in developing. Four of the factors were categorized as non-BC Hydro factors.

Specifically, respondents were asked to record the percent share they would credit each of the nine factors for making their 'non-participating' projects perform 'better than code' such that the percent shares summed to 100 percent. Note that for any given respondent, a BC Hydro factor was not shown – via the survey's programming logic – if the respondent previously indicated having had no experience with the factor. In this scenario, the factor was effectively rendered a 0 percent share.

- BC Hydro Factors
  - My learnings and experience from having had other projects go through BC Hydro's Commercial New Construction program;
  - My learnings and experience from having attended BC Hydro workshops;
  - My learnings from having reviewed the case studies and resource literature posted on BC Hydro's website;
  - My learnings from having reviewed the Building Envelope Thermal Bridging Guide; and
  - My learnings from having reviewed the Enhanced Thermal Performance Spreadsheet.
- Non-BC Hydro Factors
  - Industry innovation and good practices (outside of BC Hydro involvement);
  - My own or my organization's desire to build such projects for LEED certification;
  - My/our client directed us to have such projects perform better than the energy efficiency requirements in the B.C. Building Code; and
  - All other factors.

For each respondent, the percent shares they credited to the five BC Hydro factors were added up to a net BC Hydro total – essentially, their attribution of their 'better than code, non-participating' projects during the evaluation period back to the Commercial New Construction Program. The grand average – the final point estimate of attribution (row F) – was then calculated as the equally weighted average among all eligible respondents.

Notably, this line of questioning around attribution was administered near the very end of the survey after respondents were taken through very comprehensive and algorithmic sets of questions about their commercial new construction projects that became occupied during the period of interest. It is believed that the sequencing and build-up of these prior questions set respondents up in a favourable position and mindset to make reliable, informed and unbiased assessments of the factors.

Appendix D Results Details

D.1 Additional Detail for Expected Energy Savings

The number of measures and expected energy savings by program offer and by industry sub-sector and end uses are given in the graphs below.

Figure D.1. Project and Savings Distribution by Program Offer

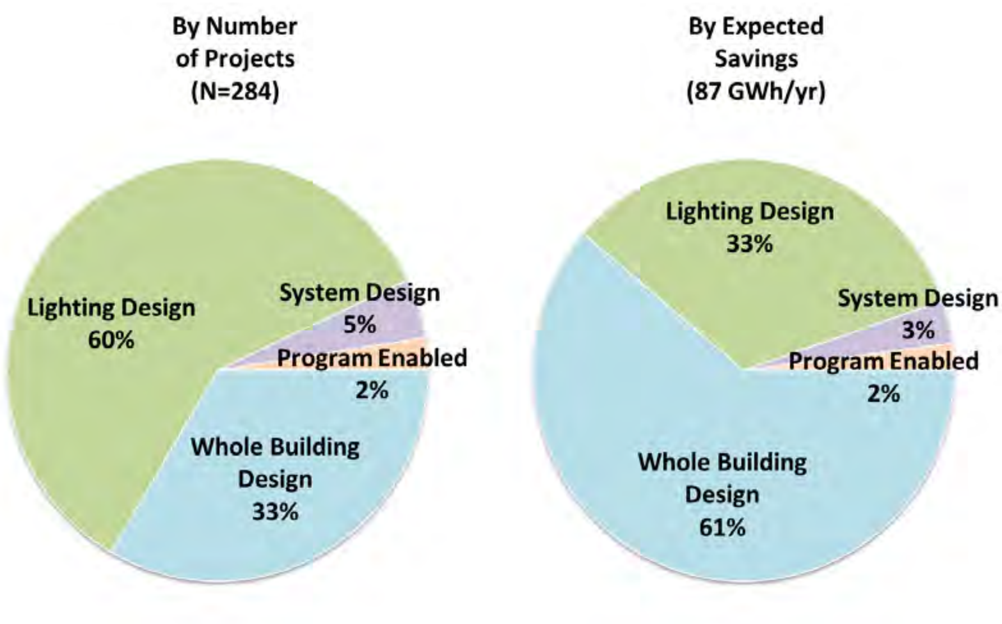


Figure D.2. Savings Distribution by Program Offers and Fiscal Year

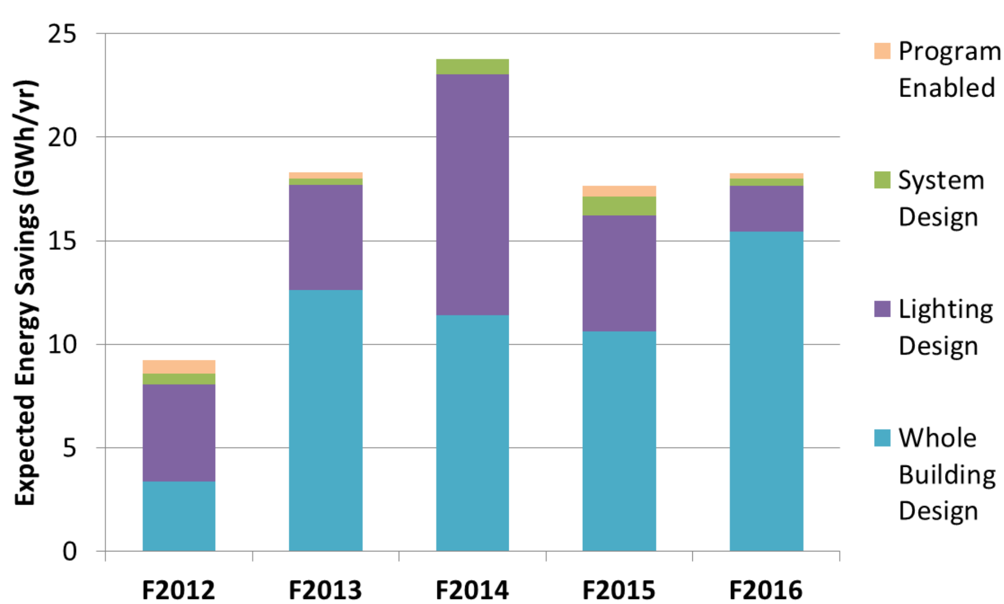


Figure D.3. Project and Savings Distribution by Sector

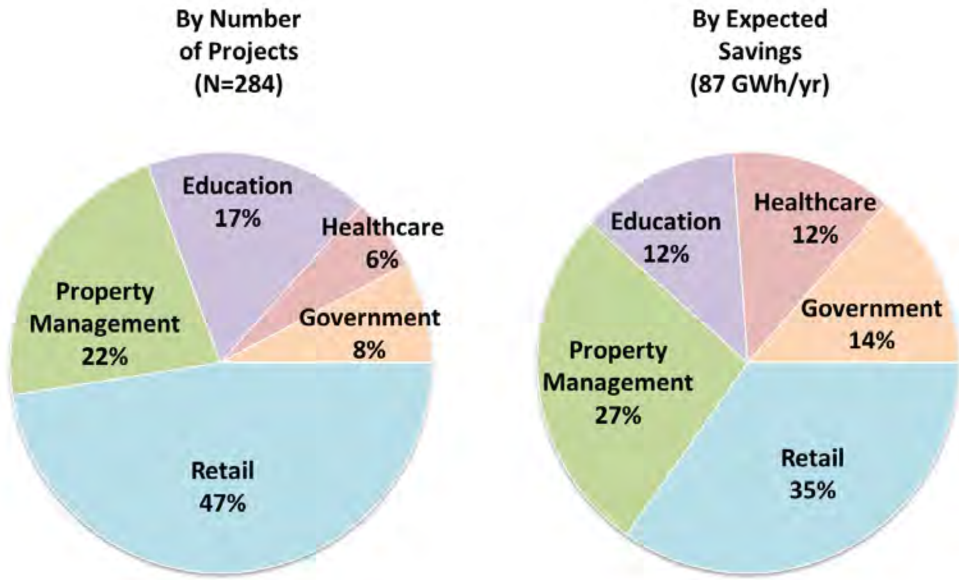


Figure D.4. Savings Distribution by Industry Sub-sector and Fiscal Year

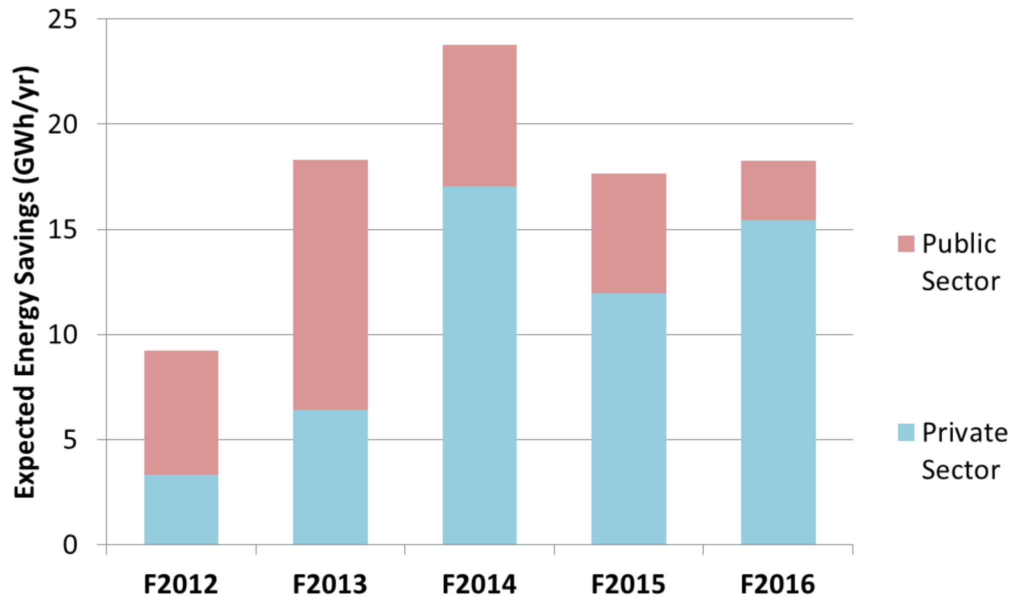
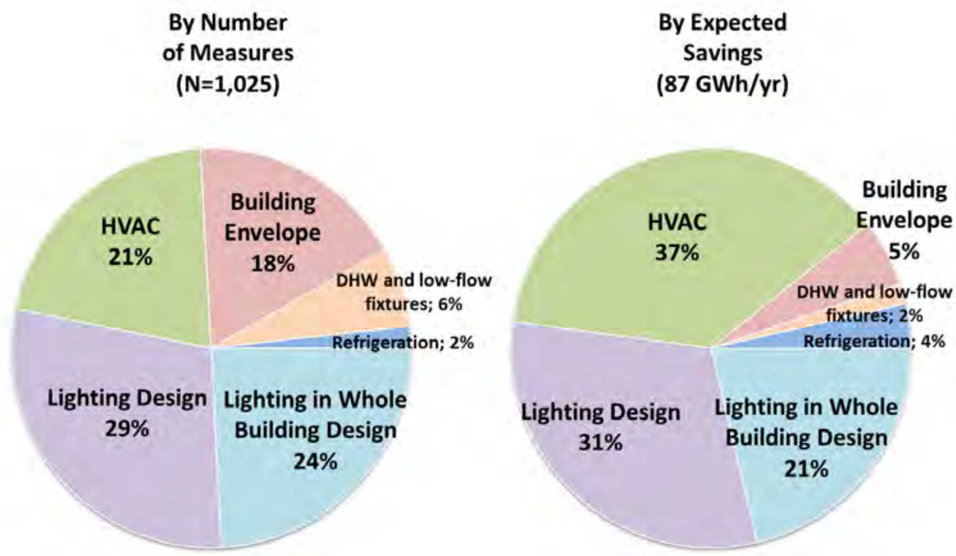
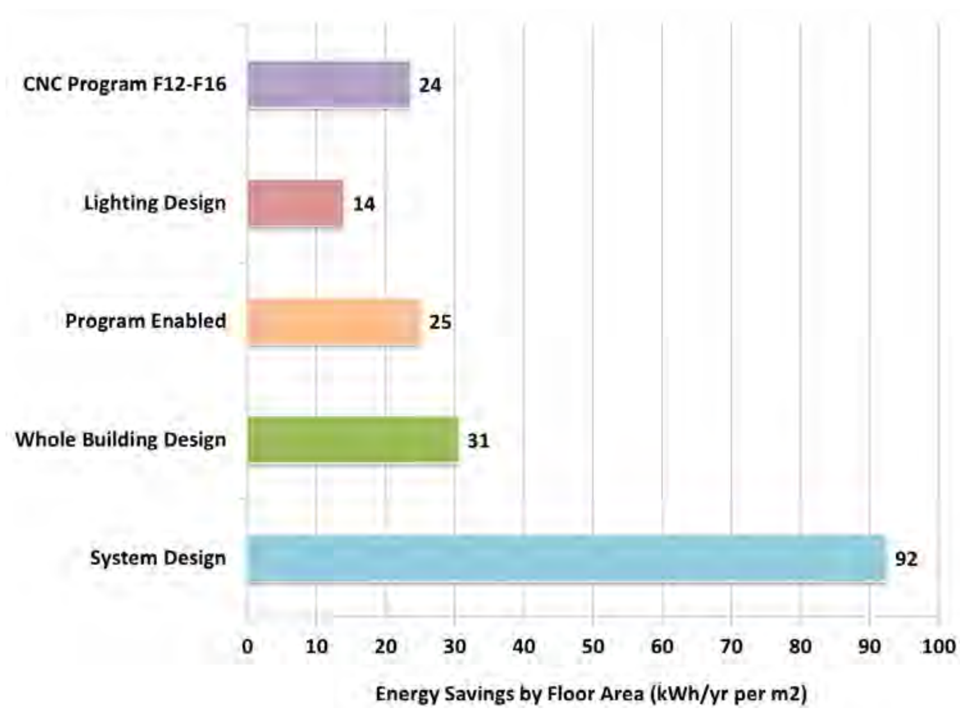


Figure D.5. Measures and Savings Distribution by End Use



The figure below illustrates the unit energy savings by affected floor area and program offer for the CNC program from F2012 through F2016. The figure shows the increasing unit energy savings from Lighting Design to Whole Building Design to System Design. Overall, the CNC program achieved building energy intensity savings of 24 kWh per year per square meter which is approximately 18 percent of the building's electricity consumption.

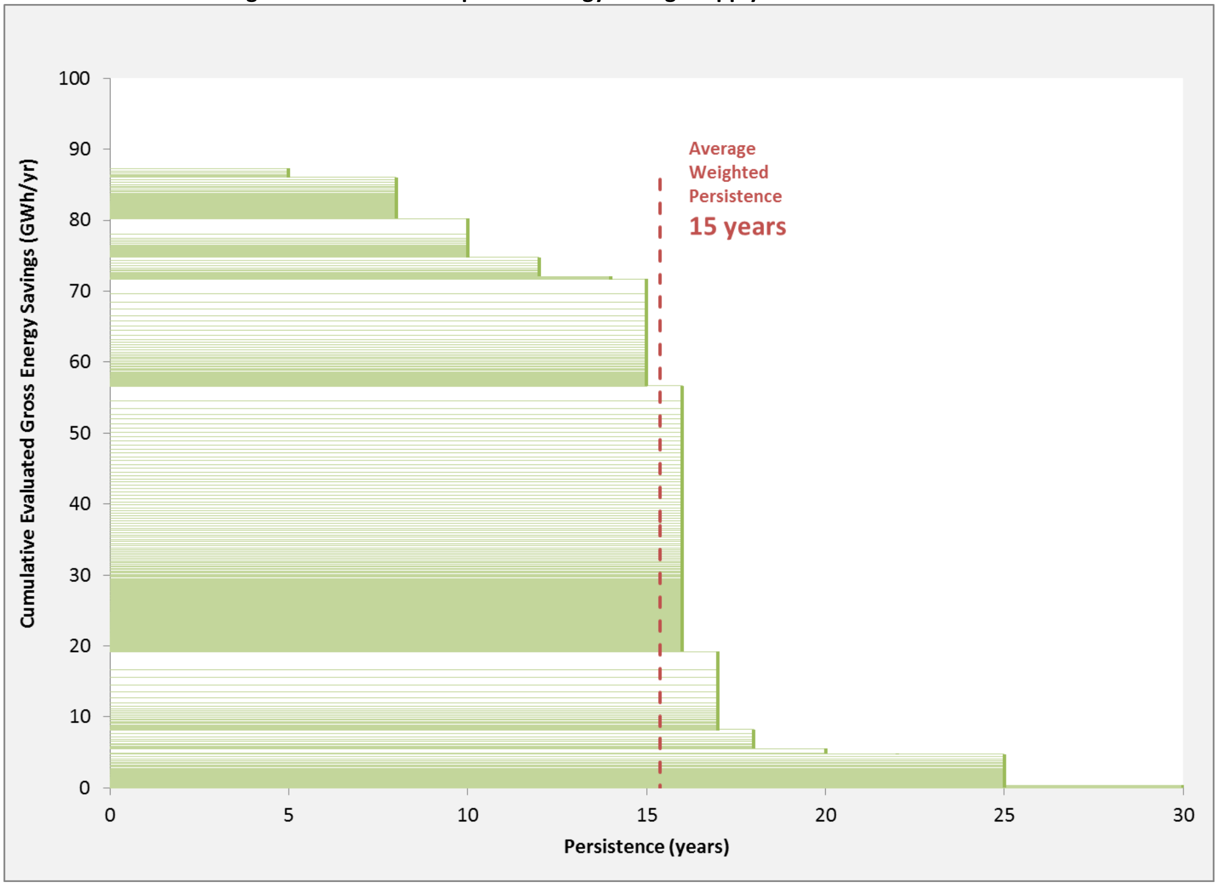
Figure D.6. Energy Savings by Affected Floor Area and Program Offer



D.3 Additional Results for Persistence

The persistence of measures was not evaluated but persistence values were assigned during the technical review of measures in accordance to the BC Hydro Persistence Standard[15]. The graph below illustrates the magnitude of expected energy savings of measures in order of increasing persistence. At the top of the chart are projects of lowest persistence (5 years) and at the bottom projects of highest persistence (30 years). In general, measures with 5 to 8 year persistence are lighting control measures; measures with 8 to 16-year persistence are hard-wired equipment and system measures; and measures with over 16 year persistence are typically upgrades to building envelope, or redesign of air distribution ductwork or water piping networks. The row height indicates the magnitude of savings. The weighted average persistence of energy savings from CNC in the F2012 – F2016 period was calculated to be 15.4 years as indicated by the dotted red vertical line.

Figure D.7. Measure Expected Energy Savings Supply and Persistence Curve



[15] BC Hydro DSM Standard: Effective Measure Life and Persistence – Revision 10, June 2016.

D.1 Additional Results from the Participant Survey

This section presents additional results from the participant survey.

Likelihood of Recommending the Program

Below are the full distributions of the likelihood of recommending the program to others and having already done so.

Figure D.8. Likelihood of Recommending the Program to Others

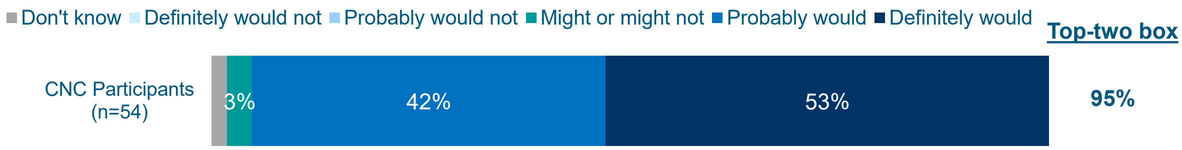
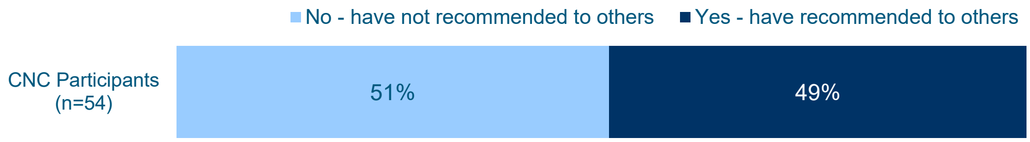


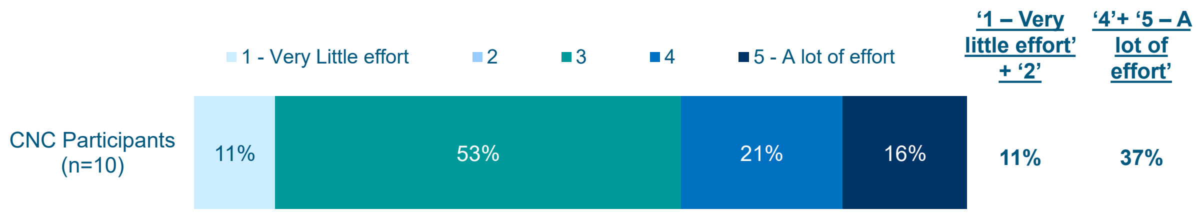
Figure D.9. Have Recommended the Program to Others



Level of Effort

Participants reported that they had put in moderate levels of effort to participate in CNC, with the bulk of respondents (53%) reporting a level of 3 on a 5-point scale. A further 37 percent reported having to put in a higher level of effort – a level of 4 or 5 on a 5-point scale. Very few (11%) reported having to put in very little effort in order to participate in the program – a score of 1 on the 5-point scale. Note that the sample size for this question is small because it was added to the survey in F2016.

Figure D.10. Level of Effort to Complete Participation in the Program



Suggestions for Improvement

Participants were asked to provide comments or suggestions about the program. In total, 25 percent of those who responded provided comments. Comments related to the process being too slow, the process being too complicated and communication issues emerged as main themes.

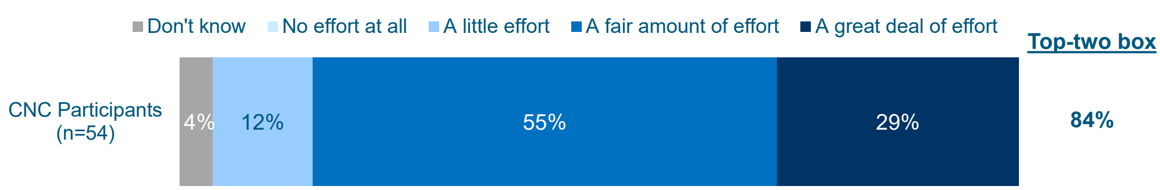
Table D.1. Comments/Suggestions for Improvement

	CNC Participants (n=15)
Process too slow / approvals take too long / speed up process	26%
Process/forms too complicated / create simpler process	24%
Communication issues / better communication with BCH/KAMs	14%
Website issues (hard to navigate, needs better info/tools)	8%
Increase variety of eligible products	4%
Increase incentive amounts	4%
Provide more information / training / seminars about program	3%
Want site visit/energy audit/in-person meeting	3%
Other program related	9%
Other non-program related	4%

Conservation Efforts and Momentum

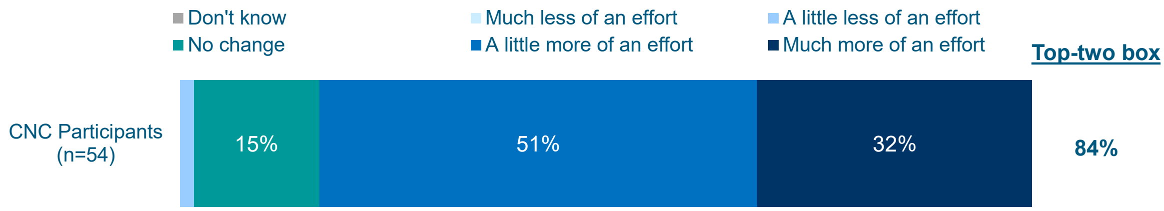
In total, 84 percent of CNC participants reported making either 'a great deal of effort' (29%) or 'a fair amount of effort' (55%) to conserve electricity over the past year. Only a small percentage reported making 'a little effort' (12%) and none reported making 'no effort at all'.

Figure D.11. Efforts to Conserve



Compared to efforts a year ago, 84 percent of participants reported increased levels of conservation effort, with 32 percent indicating that they had made 'much more of an effort' and 51 percent indicating that they had made 'a little more of an effort'. A further 15 percent indicated that there was 'no change', while only 2 percent indicated making less of an effort.

Figure D.12. Conservation Momentum



Energy Management Motivators

Participants were asked to rate various motivators to manage their use of electricity over the past year. 'Key account managers' and the 'CNC program' emerged as major factors. Other top motivators included 'reducing electricity use to make operating costs as low as possible' and an 'energy manager'. Note that the sample sizes for this question are small for two reasons: 1) the scale for this question was changed starting in F2013 (from an influence scale to a major/minor scale) and results from F2012 have thus been excluded and 2) due to the overall length of the survey, this bank of questions is not asked every survey wave.

Table D.2. Motivators to Manage Use of Electricity Over the Past Year

	Major Factor (n=10)
Key Account Manager (among those with a KAM; n=5)	65%
CNC program	60%
Reducing electricity use to make operating costs as low as possible	44%
Energy Manager	44%
Reducing electricity use to benefit the environment – it's just the right thing to do	37%
The incentive to conserve electricity that is built into BC Hydro's rate structure	37%
Overall level of electricity prices	34%
Increased funds within your company for energy-efficient retrofits	32%
Focus on cost cutting measures due to any economic downturn	23%
Federal, Provincial, or Local government initiatives	9%
Employees	9%
Contractors, vendors or customers	9%

Percentages shown are for 'major factor based on a 3-point labelled scale: major factor, minor factor, and not a factor. 'Don't know' responses are included in the calculation of percentages. Scale changed in F2013; responses from F2012 have been excluded.

Energy Management Barriers

Participants were also asked about barriers to manage electricity over the past year. The factors that emerged as the largest barriers were 'lack of funds for energy efficiency retrofits/projects', that there are 'other operational priorities' and 'lack of financial incentives for conservation programs and energy efficiency'.

Table D.3. Barriers to Manage Use of Electricity Over the Past Year

	Major Factor (n=22)
Lack of funds for energy efficient retrofits/projects	33%
There are other operational priorities	29%
Lack of financial incentives for conservation programs and energy efficiency	26%
Interruption to business operations	14%
Lack of staffing/staffing requirements	11%
Can't control employees' behaviour in regards to energy efficiency practice	7%
Takes too much time	3%
Current usage is already near its lowest possible level	3%
Lack of knowledge of where the opportunities for savings might be	0%
All equipment is functioning efficiently as possible	0%
Currently leasing the property and no property changes are permitted	0%

Percentages shown are for 'major barrier' based on a 3-point labelled scale: major barrier, minor barrier, and no barrier.
'Don't know' responses are included in the calculation of percentages.

Program Participation

While the questions below were used primarily as inputs to the free rider algorithm, looking at them individually can provide additional insights into the decision making process for implementing energy efficient upgrades, as well as provide insights on the role that each plays in the free ridership score. Recall, however, that free ridership is calculated using a decision tree with the individual questions receiving scoring based on the response options selected. Note also that the overall free rider score was weighted based on savings. Further details about the free rider algorithm and the scoring for each element are discussed in Appendix C.2.

Project Completion and Timing

As part of the timing question, organizations stated whether or not the energy efficiency project would have gone ahead without assistance from the CNC program. All participants indicated that that the project would have gone ahead in some form even in the absence of the program, comprised both of those who were able to provide an estimate of the timing and those who were unsure of timing. The vast majority would have completed the project at the same time (76%), while the next largest proportion was unsure about timing (16%).

Note that while timing of the project was explored in the survey, it was excluded from the algorithm due to the nature of CNC projects. Due to the high cost and long lifespan of the types of projects CNC pertains to, if a particular energy efficient technology is not installed as part of the initial construction, it is unlikely that it would be brought in to replace a less efficient technology in the short to medium term. It would not be financially feasible to replace a recently installed technology with a more energy efficient one – it is either included as part of initial construction or not replaced again until the long term.

Table D.4. Project Completion and Timing

We would have completed the project…	CNC Participants (n=51)
...at about the same time as actually done so	76%
...within a year of when actually done so	4%
...more than a year but less than 3 years later	0%
...more than 3 years later	0%
My organization would have completed this project, but I am unsure about the timing	16%
My organization would NOT have completed this project	0%
Don't know	4%
Total	100%

Prior Plans

A total of 41 percent of CNC participants reported that the idea to implement the energy efficiency measures was first suggested through BC Hydro assistance, such as a BC Hydro-funded energy consultant, BC Hydro-funded Energy Manager or a BC Hydro representative. A total of 43 percent of participants had the idea to implement the measure prior to suggestion by BC Hydro, while the remaining 16 percent were unsure about prior plans.

Table D.5. Prior Plans

	CNC Participants (n=51)
Yes, the idea was first suggested through BC Hydro assistance	41%
No, the ideas was NOT first suggested through BC Hydro assistance	43%
Don't know	16%
Total	100%

Among those who would have completed the project even if assistance from CNC had not existed.

Energy Efficiency

Participants were asked what level of energy efficiency they would have implemented in absence of the program. A total of 45% would have done so with a lower energy efficiency than actually implemented, while 41% would have installed the same efficiency as actually done so.

Table D.6. Energy Efficiency

We would have completed the measure with…	CNC Participants (n=51)
…a LOWER ENERGY EFFICIENCY than actually installed	45%
…the SAME ENERGY EFFICIENCY as actually installed	41%
…a HIGHER ENERGY EFFICIENCY than actually installed	2%
Not applicable	2%
Don't know	10%
Total	100%

Among those who would have completed the project even if assistance from CNC had not existed.

Financial Criteria

A total of 45 percent of participants indicated that the project would have met their organization's financial criteria around site investments, even without assistance from the program. A similar proportion indicated that it would not have met their financial criteria (43%), while the remainder were either unsure or felt that the financial criteria was not applicable to the project. Lighting design projects were more likely to have met an organization's financial criteria than whole building design projects (56% versus 40%). Note that although for-profit businesses rely heavily on the financial bottom line, projects often still proceed even if they do not meet an organization's financial criteria due to other factors (e.g., anticipated change of regulations, market prices, etc.).

Table D.7. Financial Criteria

	CNC Participants (n=51)
Yes, it would have met our financial criteria	45%
No, it would NOT have met our financial criteria	43%
Not applicable	4%
Don't know	8%
Total	100%

Among those who would have completed the project even if assistance from CNC had not existed.

Scale of Project

About one-quarter of participants who believed they would have completed the project on their own even without assistance from the program would have completed it at the same scale or higher. A further 40 percent would have completed between 50% and 99% of the project on their own, while only 8 percent would have completed less than half of it.

Table D.8. Scale of Project

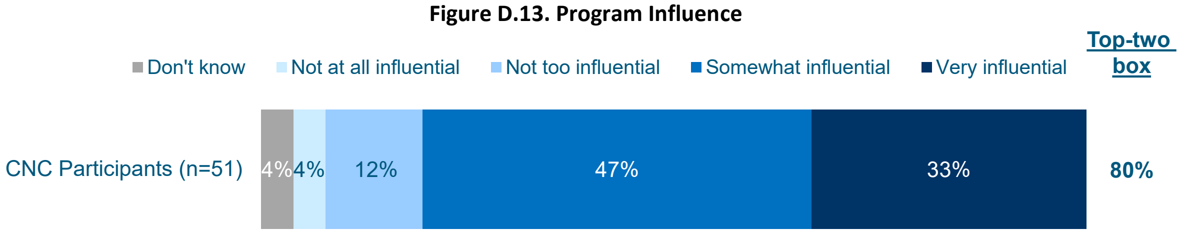
	CNC Participants (n=51)
0%	0%
1% to 24%	2%
25% to 49%	6%
50% to 74%	12%
75% to 99%	28%
100% or greater	28%
Not applicable	4%
Don't know	20%
Total	100%

Among those who would have completed the project even if assistance from CNC had not existed.

Program Influence

Participants were asked how influential the program was on their organization's decision to implement the measures. In total, 80 percent of participants reported that the program was 'very influential' or 'somewhat influential' on their decision to do so. A further 12 percent indicated that the program had been 'not too influential' while 4 percent indicated that it had been 'not at all influential'.

Figure D.13. Program Influence

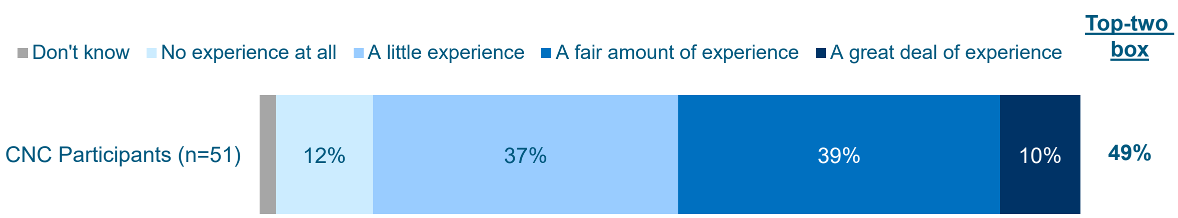


Among those who would have completed the project even if assistance from CNC had not existed.

Prior Experience with Measure/Technology Installed

Prior experience with the measures or technologies installed was fairly evenly distributed, with about half of participants having at least at least a fair amount of experience and half having little to no experience. Note that this question was not used in the free rider algorithm.

Figure D.14. Prior Experience with Measures/Technologies Installed



Appendix E Market Actor Survey – Questionnaire

Commercial New Construction – Market Actor Survey

Welcome to BC Hydro's Commercial New Construction Survey.

As the commercial new construction industry in British Columbia continues in its drive to build and operate higher performing and more energy efficient buildings, it is important to understand 'where it is currently at' in this regard.

While BC Hydro has very deep insights into the building projects that have come through its own Commercial New Construction Program, it has fewer and less reliable insights in regards to the many more projects that have not come through its program.

To this end, BC Hydro is embarking on a study to estimate the extent that new construction projects in the province are energy efficient. We are particularly interested in understanding the buildings or major additions that became occupied from 2012 to 2016 for which you may have had a decision making role regarding the extent that the projects would be energy efficient.

Again, our interest in this study is about the commercial new construction projects in the province that have not received direct BC Hydro funding or support.

The survey will likely take 30 minutes to work through, but we have tried to make your participation as easy as possible by allowing you to log on/off of the survey to complete it at your leisure. The next screen page will show you how.

For privacy reasons, do not self-identify (unless for the purposes of entering the contest) or identify other specific individuals in your written comments. Any comments including self-identification or identification of third parties will be discarded.

Thank you for your participation, your opinions are extremely important to us.

Cohesium Research, an independent research company based in B.C., is assisting us to conduct this survey. Your responses will be held in strict confidence by BC Hydro's Evaluation department and will be compiled with those of other customers for the research and planning purposes as identified above.

If you have any further questions about how to complete your survey, please contact please contact Connie Cheng, Project Manager, Cohesium Research at conniecheng@cohesiumresearch.com. If you have questions about why BC Hydro is conducting this research, please contact Marc Pedersen, Senior Evaluation Specialist at marc.pedersen@bchydro.com.

The personal information gathered through this study, including your opinions, demographic information, and name (if you choose to provide it at the end of the survey for participation in the prize draw) is being collected in furtherance of BC Hydro's electricity conservation mandate under the Clean Energy Act.

About You and Your Work

1. To begin the survey, can you please confirm that at least some of your work over the past 5-10 years has been in regards to the commercial new construction market in British Columbia?

By this we mean work that informs new construction or building additions in the commercial (e.g., offices and retail stores), institutional (e.g., schools & universities, hospitals), and multi-unit residential sectors.

☐[1] Yes

☐[0] No ⇒ SKIP TO Q70

☐[99] Don't know ⇒ SKIP TO Q70

2. Consider the commercial new construction projects you worked on that became occupied between 2012 and 2016.

Which one of the following statements best describes your involvement in the decisions regarding the extent that the projects would be energy efficient?

- **Decisions for such projects very likely occurred some three to five years prior to when they became occupied.**
- **Decisions regarding a project's energy efficiency may pertain to the building's envelope, its heating, cooling and ventilation systems, service water heating, its lighting system and its plug-load system.**

☐[1] I was often a key decision maker in the extent that projects would be energy efficient

☐[2] I typically was not a key decision maker, but did provide inputs, alternate options and/or my opinions into the decision making process

☐[3] I typically had little or no role in the decision making process ⇒ SKIP TO Q70

☐[99] Don't know ⇒ SKIP TO Q70

3. Consider the commercial (Part 3) new construction projects in B.C. for which you had any sort of decision making role regarding the extent that the projects would be energy efficient and only those that became occupied between 2012 and 2016. What segments of the market were the projects a part of?

- **Decisions for such projects very likely occurred some three to five years prior to when they became occupied.**
- **New construction projects include buildings and/or major additions in the commercial, institutional and the multi-unit residential sectors.**

Select all that apply.

☐[1] Hospitals and other health care facilities

☐[2] Grocery stores

☐[3] Mixed-use buildings

☐[4] Multi-unit residential buildings

☐[5] Non-food retail stores

☐[6] Office buildings

☐[7] Restaurants/Fast food

☐[8] Schools

☐[9] Universities

☐[98] Other (please specify): ______________________________

☐[99] Don’t know ⇒ SKIP TO Q70

4. What was your specific role regarding the extent that that the new construction projects in B.C. – those that became occupied between 2012 and 2016 – would be energy efficient?

- **Decisions in such projects very likely occurred some three to five years prior to when they became occupied.**
- **New construction projects include buildings and/or major additions in the commercial, institutional and the multi-unit residential sectors.**

Select all that apply.

☐[1] Architect

☐[2] Electrical engineer

☐[3] Energy modeller

☐[4] Mechanical engineer

☐[5] Project developer/development

☐[6] Project financing

☐[7] Project management

☐[8] Quantity surveyor

☐[9] Real estate

☐[10] Specifications writer

☐[98] Other (please specify): ______________________________

☐[99] Don't know

5. How many years have you had any decision making roles regarding the extent that new construction projects would be energy efficient?

☐[1] Less than 2 years

☐[2] 2 years to less than 5 years

☐[3] 5 years to less than 10 years

☐[4] 10 years to less than 25 years

☐[5] 25 years or more

☐[99] Don't know

6. Intentionally left empty

7. Intentionally left empty

8. Intentionally left empty

9. Intentionally left empty

BC Hydro's Commercial New Construction Program

10. Previously known as BC Hydro's High Performance Buildings program until 2009, the Commercial New Construction program assists in the design and construction of new high performance and energy efficient institutional, commercial, and multi-unit residential buildings in B.C.

The program encourages developers and their design teams to adopt energy-efficient design early in the design process, and provides them with a range of tools and potential financial incentives.

Which of the following statements best reflects your awareness and experience with BC Hydro's Commercial New Construction program?

☐2 I have worked on projects that have come through BC Hydro's Commercial New Construction program and/or the High Performance Buildings program

☐1 I was previously aware of the program, but I don't believe that I have ever worked on any projects that came through it

☐0 I was not previously aware of the program

CONTINUE WITH Q11 IF Q10=2; ELSE SKIP TO Q12

11. Please consider once again the new construction projects in B.C. – that eventually became occupied in 2012 to 2016 – for which you had any sort of decision making role regarding the extent that a project would be energy efficient.

Did any of those projects come through BC Hydro's Commercial New Construction program?

☐1 Yes

☐0 No

☐99 Don't know

12. BC Hydro has offered workshops and training in the past – sometimes in partnership with the APEGBC, IES, AIBC and IBPA – in regards to new building construction.

Have you ever attended one of these workshops or training opportunities?

☐1 Yes

☐0 No

☐99 Don't know

13. BC Hydro's Commercial New Construction program has case studies and resource literature in regards to new building construction posted on its website.

Have you ever reviewed these case studies and resource literature?

- **Building Envelope Thermal Bridging Guide**
- **Accounting for Thermal Bridging at Interface Details**
- **New Construction Energy Modelling Guideline**
- **New Construction Lighting Calculator**
- **Recommended lamp and ballast wattages**
- **City of Vancouver Energy Modelling Guidelines**
- **GeoExchange BC Professional Guidelines**

☐1 Yes

☐0 No

☐99 Don't know

14. Aside from the interactions you may have had with BC Hydro staff at workshops and other formal events, have you ever had other discussions with them about your projects in B.C.?

☐1 Yes

☐0 No

☐99 Don't know

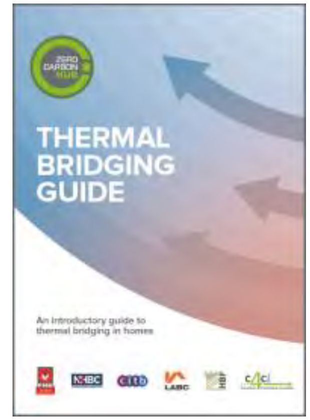
15. BC Hydro was a prime sponsor and contributor of the Building Envelope Thermal Bridging Guide which details how the commercial new construction market can effectively account for the impact of thermal bridging as part of meeting the challenges of reducing energy use in buildings.

Have you ever reviewed the Building Envelope Thermal Bridging Guide?

☐[1] Yes

☐[0] No

☐[99] Don't know



16. BC Hydro provided technical support and funding in developing the Enhanced Thermal Performance Spreadsheet which is included in BC Hydro's energy modelling guidelines.

Have you ever reviewed the Enhanced Thermal Performance Spreadsheet?

☐[1] Yes

☐[0] No

☐[99] Don't know

17. Intentionally left empty

The New Construction Projects You Have Worked On

18. The diagram below illustrates the flow of questions that will be asked of you in the subsequent sections.

1. Total floor area of the projects in B.C. – that became occupied in 2012 through 2016 – you had a decision making role regarding the extent that a project would be energy efficient.

⇩

2. The total floor area of your projects (from 1 above) that is performing better than the energy efficiency requirements in the B.C. Building Code

⇩

3. For your projects that are performing better than the energy efficiency requirements in the B.C. Building Code (from 2 above), the floor area that did and did not come through the program

⇩

4. Building types associated with the 'better than code, non-participating' floor area (from 3 above)

⇩

5. Measures implemented and estimated electricity savings for the 'better than code, non-participating' floor area (from 3 and 4 above)

⇩

6. Influence of factors on your decisions

19.

The remaining portions of this survey are about the new building and major addition construction projects you worked on that became occupied between 2012 and 2016.

20. For each of the five years presented in the table below, please estimate how many new construction projects in B.C. – that eventually became occupied in 2012 to 2016 – for which you had any sort of decision making role regarding the extent that a project would be energy efficient.

Of course, your involvement in such projects very likely occurred some three to five years prior to when they became occupied.

- **New construction projects include buildings and/or major additions in the commercial, institutional and the multi-unit residential sectors.**
- **Your best estimate or recollection is all that is requested.**

	Projects that became occupied in 2012 ⇓	Projects that became occupied in 2013 ⇓	Projects that became occupied in 2014 ⇓	Projects that became occupied in 2015 ⇓	Projects that became occupied in 2016 ⇓
Number of projects you had a decision making role regarding the extent that a project would be energy efficient?	________ ☐[0] None ☐[99] Don't know	________ ☐[0] None ☐[99] Don't know	________ ☐[0] None ☐[99] Don't know	________ ☐[0] None ☐[99] Don't know	________ ☐[0] None ☐[99] Don't know

ALLOWABLE RANGE OF TEXT FIELD 1-98

IF NONE FOR ALL YEARS 2012-2016, THEN SKIP TO Q71

21. Related to the previous question, we would like to understand the total floor area of the new construction projects in B.C. – that eventually became occupied in 2012 to 2016 – for which you had any sort of decision making role regarding the extent that a project would be energy efficient.

Please estimate the total floor area (square feet) associated with those projects.

- **Your involvement in such projects very likely occurred some three to five years prior to when they became occupied.**
- **New construction projects include buildings and/or major additions in the commercial, institutional and the multi-unit residential sectors.**
- **You may enter an estimate in the field, or choose from the ranges provided.**
- **Your best estimate or recollection is all that is requested.**

SHOW GRID YEARS FOR ONLY WHERE PROJECTS IN Q20 =>1 (DON'T KNOWS INCLUDED)

	Projects that became occupied in 2012 ⇓	Projects that became occupied in 2013 ⇓	Projects that became occupied in 2014 ⇓	Projects that became occupied in 2015 ⇓	Projects that became occupied in 2016 ⇓
Number of new construction projects:	[INSERT # OF PROJECTS FROM Q20]	[INSERT # OF PROJECTS FROM Q20]	[INSERT # OF PROJECTS FROM Q20]	[INSERT # OF PROJECTS FROM Q20]	[INSERT # OF PROJECTS FROM Q20]
Total floor area (square feet) of the projects you had a decision making role regarding the extent that a project would be energy efficient?	_________ ft^2 ☐[1] < 50,000 ft^2 ☐[2] 50,000 - 99,999 ☐[3] 100,000 - 249,999 ☐[4] 250,000 - 499,999 ☐[5] 500,000 - 999,999 ☐[6] 1,000,000 ft^2 + ☐[99] Don't know	_________ ft^2 ☐[1] < 50,000 ft^2 ☐[2] 50,000 - 99,999 ☐[3] 100,000 - 249,999 ☐[4] 250,000 - 499,999 ☐[5] 500,000 - 999,999 ☐[6] 1,000,000 ft^2 + ☐[99] Don't know	_________ ft^2 ☐[1] < 50,000 ft^2 ☐[2] 50,000 - 99,999 ☐[3] 100,000 - 249,999 ☐[4] 250,000 - 499,999 ☐[5] 500,000 - 999,999 ☐[6] 1,000,000 ft^2 + ☐[99] Don't know	_________ ft^2 ☐[1] < 50,000 ft^2 ☐[2] 50,000 - 99,999 ☐[3] 100,000 - 249,999 ☐[4] 250,000 - 499,999 ☐[5] 500,000 - 999,999 ☐[6] 1,000,000 ft^2 + ☐[99] Don't know	_________ ft^2 ☐[1] < 50,000 ft^2 ☐[2] 50,000 - 99,999 ☐[3] 100,000 - 249,999 ☐[4] 250,000 - 499,999 ☐[5] 500,000 - 999,999 ☐[6] 1,000,000 ft^2 + ☐[99] Don't know

IF DON'T KNOW IN EACH GRID YEAR SHOWN, THEN SKIP TO Q63

22. As shown below, you previously estimated the total floor area of the new construction projects in B.C. – that eventually became occupied in 2012 to 2016 – for which you had any sort of decision making role regarding the extent that a project would be energy efficient.

What percent of the total floor area of those projects would you estimate is performing better – including just slightly better – than the energy efficiency requirements in the B.C. Building Code (ASHRAE 90.1 / NECB 2011)?

- **Your best estimate or recollection is all that is requested.**

SHOW GRID YEARS FOR ONLY WHERE Q21 VALUES =1-6 OR RESPONSE IN TEXT FIELD

	Projects that became occupied in 2012 ⇓	Projects that became occupied in 2013 ⇓	Projects that became occupied in 2014 ⇓	Projects that became occupied in 2015 ⇓	Projects that became occupied in 2016 ⇓
Total floor area of your projects that you had a decision making role regarding the extent that a project would be energy efficient	[INSERT RESPONSE FROM Q21] ft^2	[INSERT RESPONSE FROM Q21] ft^2	[INSERT RESPONSE FROM Q21] ft^2	[INSERT RESPONSE FROM Q21] ft^2	[INSERT RESPONSE FROM Q21] ft^2
Percentage of floor area of your projects that is performing better than the energy efficiency requirements in the B.C. Building Code?	☐0 0% of the floor area ☐1 10% ☐2 20% ☐3 30% ☐4 40% ☐5 50% ☐6 60% ☐7 70% ☐8 80% ☐9 90% ☐10 100% of the floor area ☐98 At least some, but don't know how much ☐99 Don't know	☐0 0% of the floor area ☐1 10% ☐2 20% ☐3 30% ☐4 40% ☐5 50% ☐6 60% ☐7 70% ☐8 80% ☐9 90% ☐10 100% of the floor area ☐98 At least some, but don't know how much ☐99 Don't know	☐0 0% of the floor area ☐1 10% ☐2 20% ☐3 30% ☐4 40% ☐5 50% ☐6 60% ☐7 70% ☐8 80% ☐9 90% ☐10 100% of the floor area ☐98 At least some, but don't know how much ☐99 Don't know	☐0 0% of the floor area ☐1 10% ☐2 20% ☐3 30% ☐4 40% ☐5 50% ☐6 60% ☐7 70% ☐8 80% ☐9 90% ☐10 100% of the floor area ☐98 At least some, but don't know how much ☐99 Don't know	☐0 0% of the floor area ☐1 10% ☐2 20% ☐3 30% ☐4 40% ☐5 50% ☐6 60% ☐7 70% ☐8 80% ☐9 90% ☐10 100% of the floor area ☐98 At least some, but don't know how much ☐99 Don't know

IF Q22=0 FOR ALL YEARS, THEN SKIP TO Q63; ASK Q23 IF Q11=1; ELSE SKIP TO Q25

23. For the new construction projects in B.C. that you had a decision making role, you previously estimated the percent of total floor area that is performing better than the energy requirements in the B.C. Building Code. The absolute floor area – for applicable years 2012 to 2016 – is shown in the table below.

What percent of the floor area of these 'better than code' projects would you estimate as having come through BC Hydro's Commercial New Construction program?

- **Your best estimate or recollection is all that is requested.**

SHOW GRID YEARS FOR ONLY WHERE Q22 VALUES =1-99

	Projects that became occupied in 2012 ⇓	Projects that became occupied in 2013 ⇓	Projects that became occupied in 2014 ⇓	Projects that became occupied in 2015 ⇓	Projects that became occupied in 2016 ⇓
Total floor area of your projects that is performing better than the energy efficiency requirements in the B.C. Building Code:	[CALCULATE ft^2 FROM RESPONSE IN Q22]; IF Q22 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE ft^2 FROM RESPONSE IN Q22]; IF Q22 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE ft^2 FROM RESPONSE IN Q22]; IF Q22 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE ft^2 FROM RESPONSE IN Q22]; IF Q22 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE ft^2 FROM RESPONSE IN Q22]; IF Q22 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'
For your projects that are performing better than the energy efficiency requirements in the B.C. Building Code, the percent of floor area that came through the program?	☐[0] 0% of the floor area (none of it came through the program) ☐[1] 10% ☐[2] 20% ☐[3] 30% ☐[4] 40% ☐[5] 50% ☐[6] 60% ☐[7] 70% ☐[8] 80% ☐[9] 90% ☐[10] 100% of the floor area (all of it came through the program) ☐[98] At least some, but don't know how much ☐[99] Don't know	☐[0] 0% of the floor area (none of it came through the program) ☐[1] 10% ☐[2] 20% ☐[3] 30% ☐[4] 40% ☐[5] 50% ☐[6] 60% ☐[7] 70% ☐[8] 80% ☐[9] 90% ☐[10] 100% of the floor area (all of it came through the program) ☐[98] At least some, but don't know how much ☐[99] Don't know	☐[0] 0% of the floor area (none of it came through the program) ☐[1] 10% ☐[2] 20% ☐[3] 30% ☐[4] 40% ☐[5] 50% ☐[6] 60% ☐[7] 70% ☐[8] 80% ☐[9] 90% ☐[10] 100% of the floor area (all of it came through the program) ☐[98] At least some, but don't know how much ☐[99] Don't know	☐[0] 0% of the floor area (none of it came through the program) ☐[1] 10% ☐[2] 20% ☐[3] 30% ☐[4] 40% ☐[5] 50% ☐[6] 60% ☐[7] 70% ☐[8] 80% ☐[9] 90% ☐[10] 100% of the floor area (all of it came through the program) ☐[98] At least some, but don't know how much ☐[99] Don't know	☐[0] 0% of the floor area (none of it came through the program) ☐[1] 10% ☐[2] 20% ☐[3] 30% ☐[4] 40% ☐[5] 50% ☐[6] 60% ☐[7] 70% ☐[8] 80% ☐[9] 90% ☐[10] 100% of the floor area (all of it came through the program) ☐[98] At least some, but don't know how much ☐[99] Don't know

24. In the previous question, you estimated the percent of floor area of your 'better than code' projects that came through BC Hydro's Commercial New Construction program. Your responses are shown in the first row of the table below.

Through subtraction, the percents of floor area of your 'better than code' projects that you believe did not come through the program are shown, and through further multiplication by your earlier responses, the total floor area of your 'better than code, non-participating' projects.

This total floor area of your 'better than code, non-participating' projects will be carried forward and shown in subsequent tables.

	Projects that became occupied in 2012 ⇓	Projects that became occupied in 2013 ⇓	Projects that became occupied in 2014 ⇓	Projects that became occupied in 2015 ⇓	Projects that became occupied in 2016 ⇓
a. Your estimate of the percent of your 'better than code' floor area that came through the program:	INSERT RESPONSE FROM Q23	INSERT RESPONSE FROM Q23	INSERT RESPONSE FROM Q23	INSERT RESPONSE FROM Q23	INSERT RESPONSE FROM Q23
b. Through subtraction, the percent of your 'better than code' floor area that did not come through the program:	CALCULATE AS 100% MINUS VALUE OF Q23 RESPONSE; or show code 98 or 99 response of Q23	CALCULATE AS 100% MINUS VALUE OF Q23 RESPONSE; or show code 98 or 99 response of Q23	CALCULATE AS 100% MINUS VALUE OF Q23 RESPONSE; or show code 98 or 99 response of Q23	CALCULATE AS 100% MINUS VALUE OF Q23 RESPONSE; or show code 98 or 99 response of Q23	CALCULATE AS 100% MINUS VALUE OF Q23 RESPONSE; or show code 98 or 99 response of Q23
c. Through multiplication, the floor area of your 'better than code, non-participating' projects:	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'

IF Q24c=0 FOR EACH YEAR SHOWN, THEN SKIP TO Q63;

OTHER RESPONDENTS COMING THROUGH THIS TABLE SKIP TO Q29 MESSAGE PAGE

25.

SHOW THIS TEXT IF (Q11=0, 99): **You previously indicated that you had worked on projects that came through BC Hydro's Commercial New Construction program, but none were projects that became occupied from 2012 to 2016.**

SHOW THIS TEXT IF (Q10=1): **You previously indicated that you have never worked on a project that came through BC Hydro's Commercial New Construction program.**

SHOW THIS TEXT IF (Q10=0): **You previously indicated that you were not previously aware of BC Hydro's Commercial New Construction program.**

For this reason you were deliberately skipped around – not asked – a question about how much of your 'better than code' projects from 2012 to 2016 came through the program. Your earlier responses suggest that <u>none</u> of it did.

Therefore, some of the forthcoming questions are populated with this in mind.

26. Intentionally left empty

27. Intentionally left empty

28. Intentionally left empty

Your 'Better than Code, Non-Participating' Projects

29.

This section is about the construction projects in B.C. you worked on that became occupied between 2012 and 2016 that are performing better than the energy efficiency requirements in the B.C. Building Code and did <u>not</u> come through BC Hydro's Commercial New Construction program.

30. For your new construction projects that are performing better than the energy efficiency requirements in the B.C. Building Code, SHOW THIS TEXT IF [(Q11=0, 99) OR Q10=0, 1)]: **you indicated or believed that none of them came through BC Hydro's Commercial New Construction program.** SHOW THIS TEXT IF Q11=1: **you previously estimated the percent of the floor area that did not come through BC Hydro's Commercial New Construction program. The absolute floor area – for each year 2012 to 2016 – is shown in the table below.**

SHOW ALL: **We are interested in learning where in the province these projects were built. For each year in the table below, please apportion the floor space of these 'better than code, non-participating' projects by the four regions of the province.**

- **For example, for the 'better than code, non-participating' floor space in 20XX, one may estimate that 80% of it was in the Lower Mainland, 10% on Vancouver Island, 5% in the Southern Interior and 5% in the North.**

IF Q11=1: SHOW EACH GRID YEAR FOR ONLY WHERE Q23 VALUES = 0-9, 98, 99

IF [(Q11=0, 99) OR Q10=0, 1)]: SHOW GRID YEARS FOR ONLY WHERE Q22 VALUES =1-99

	Projects that became occupied in 2012 ⇓	**Projects that became occupied in 2013 ⇓**	**Projects that became occupied in 2014 ⇓**	**Projects that became occupied in 2015 ⇓**	**Projects that became occupied in 2016 ⇓**
Floor area of your 'better than code, non-participating' projects:	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'
Lower Mainland	_____ %	_____ %	_____ %	_____ %	_____ %
Vancouver Island	_____ %	_____ %	_____ %	_____ %	_____ %
Southern Interior	_____ %	_____ %	_____ %	_____ %	_____ %
North	_____ %	_____ %	_____ %	_____ %	_____ %
Your total	**SHOW RUNNING**	**SHOW RUNNING**	**SHOW RUNNING**	**SHOW RUNNING**	**SHOW RUNNING**
Target Total	**100%**	**100%**	**100%**	**100%**	**100%**
Don't know	☐[99] Don't know	☐[99] Don't know	☐[99] Don't know	☐[99] Don't know	☐[99] Don't know

31. For these 'better than code, non-participating projects, we would like to learn what portion of them received 1) whole building energy modelling, 2) a refrigeration system design study, and/or 3) a lighting design study.

For each year in the table below, first estimate the percent of the floor area of those 'better than code, non-participating' projects that received whole building energy modelling.

Note: do not include any separate lighting studies in this grid; do not include any separate refrigeration system design studies.

IF Q11=1: SHOW EACH GRID YEAR FOR ONLY WHERE Q23 VALUES = 0-9, 98, 99

IF [(Q11=0, 99) OR Q10=0, 1)]: SHOW GRID YEARS FOR ONLY WHERE Q22 VALUES =1-99

	Projects that became occupied in 2012 ⇓	Projects that became occupied in 2013 ⇓	Projects that became occupied in 2014 ⇓	Projects that became occupied in 2015 ⇓	Projects that became occupied in 2016 ⇓
Floor area of your 'better than code, non-participating' projects:	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'
For your projects that are performing better than the energy efficiency requirements in the B.C. Building Code and did not come through the program, the percent of the floor area that received whole building energy modelling?	☐0 0% of the floor area ☐1 10% ☐2 20% ☐3 30% ☐4 40% ☐5 50% ☐6 60% ☐7 70% ☐8 80% ☐9 90% ☐10 100% of the floor area ☐98 At least some, but don't know how much ☐99 Don't know	☐0 0% of the floor area ☐1 10% ☐2 20% ☐3 30% ☐4 40% ☐5 50% ☐6 60% ☐7 70% ☐8 80% ☐9 90% ☐10 100% of the floor area ☐98 At least some, but don't know how much ☐99 Don't know	☐0 0% of the floor area ☐1 10% ☐2 20% ☐3 30% ☐4 40% ☐5 50% ☐6 60% ☐7 70% ☐8 80% ☐9 90% ☐10 100% of the floor area ☐98 At least some, but don't know how much ☐99 Don't know	☐0 0% of the floor area ☐1 10% ☐2 20% ☐3 30% ☐4 40% ☐5 50% ☐6 60% ☐7 70% ☐8 80% ☐9 90% ☐10 100% of the floor area ☐98 At least some, but don't know how much ☐99 Don't know	☐0 0% of the floor area ☐1 10% ☐2 20% ☐3 30% ☐4 40% ☐5 50% ☐6 60% ☐7 70% ☐8 80% ☐9 90% ☐10 100% of the floor area ☐98 At least some, but don't know how much ☐99 Don't know

32. And what percent of the floor area of those 'better than code, non-participating' projects received a refrigeration system design study?

IF Q11=1: SHOW EACH GRID YEAR FOR ONLY WHERE Q23 VALUES = 0-9, 98, 99

IF [(Q11=0, 99) OR Q10=0, 1)]: SHOW GRID YEARS FOR ONLY WHERE Q22 VALUES =1-99

	Projects that became occupied in 2012 ⇓	Projects that became occupied in 2013 ⇓	Projects that became occupied in 2014 ⇓	Projects that became occupied in 2015 ⇓	Projects that became occupied in 2016 ⇓
Floor area of your 'better than code, non-participating' projects:	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft² IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft² IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft² IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft² IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft² IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'
For your projects that are performing better than the energy efficiency requirements in the B.C. Building Code and did not come through the program, the percent of the floor area that received a refrigeration system design study?	☐[0] 0% of the floor area ☐[1] 10% ☐[2] 20% ☐[3] 30% ☐[4] 40% ☐[5] 50% ☐[6] 60% ☐[7] 70% ☐[8] 80% ☐[9] 90% ☐[10] 100% of the floor area ☐[98] At least some, but don't know how much ☐[99] Don't know	☐[0] 0% of the floor area ☐[1] 10% ☐[2] 20% ☐[3] 30% ☐[4] 40% ☐[5] 50% ☐[6] 60% ☐[7] 70% ☐[8] 80% ☐[9] 90% ☐[10] 100% of the floor area ☐[98] At least some, but don't know how much ☐[99] Don't know	☐[0] 0% of the floor area ☐[1] 10% ☐[2] 20% ☐[3] 30% ☐[4] 40% ☐[5] 50% ☐[6] 60% ☐[7] 70% ☐[8] 80% ☐[9] 90% ☐[10] 100% of the floor area ☐[98] At least some, but don't know how much ☐[99] Don't know	☐[0] 0% of the floor area ☐[1] 10% ☐[2] 20% ☐[3] 30% ☐[4] 40% ☐[5] 50% ☐[6] 60% ☐[7] 70% ☐[8] 80% ☐[9] 90% ☐[10] 100% of the floor area ☐[98] At least some, but don't know how much ☐[99] Don't know	☐[0] 0% of the floor area ☐[1] 10% ☐[2] 20% ☐[3] 30% ☐[4] 40% ☐[5] 50% ☐[6] 60% ☐[7] 70% ☐[8] 80% ☐[9] 90% ☐[10] 100% of the floor area ☐[98] At least some, but don't know how much ☐[99] Don't know

33. And what percent of the floor area of those 'better than code, non-participating' projects received a lighting design study?

IF Q11=1: SHOW EACH GRID YEAR FOR ONLY WHERE Q23 VALUES =0-9, 98, 99

IF [(Q11=0, 99) OR Q10=0, 1)]: SHOW GRID YEARS FOR ONLY WHERE Q22 VALUES =1-99

	Projects that became occupied in 2012 ⇓	Projects that became occupied in 2013 ⇓	Projects that became occupied in 2014 ⇓	Projects that became occupied in 2015 ⇓	Projects that became occupied in 2016 ⇓
Floor area of your 'better than code, non-participating' projects:	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'
For your projects that are performing better than the energy efficiency requirements in the B.C. Building Code and did not come through the program, the percent of the floor area that received a lighting design study?	☐0 0% of the floor area ☐1 10% ☐2 20% ☐3 30% ☐4 40% ☐5 50% ☐6 60% ☐7 70% ☐8 80% ☐9 90% ☐10 100% of the floor area ☐98 At least some, but don't know how much ☐99 Don't know	☐0 0% of the floor area ☐1 10% ☐2 20% ☐3 30% ☐4 40% ☐5 50% ☐6 60% ☐7 70% ☐8 80% ☐9 90% ☐10 100% of the floor area ☐98 At least some, but don't know how much ☐99 Don't know	☐0 0% of the floor area ☐1 10% ☐2 20% ☐3 30% ☐4 40% ☐5 50% ☐6 60% ☐7 70% ☐8 80% ☐9 90% ☐10 100% of the floor area ☐98 At least some, but don't know how much ☐99 Don't know	☐0 0% of the floor area ☐1 10% ☐2 20% ☐3 30% ☐4 40% ☐5 50% ☐6 60% ☐7 70% ☐8 80% ☐9 90% ☐10 100% of the floor area ☐98 At least some, but don't know how much ☐99 Don't know	☐0 0% of the floor area ☐1 10% ☐2 20% ☐3 30% ☐4 40% ☐5 50% ☐6 60% ☐7 70% ☐8 80% ☐9 90% ☐10 100% of the floor area ☐98 At least some, but don't know how much ☐99 Don't know

34. We are interested in learning about the types of buildings associated with the projects that are performing better than the energy efficiency requirements in the B.C. Building Code and that did not come through BC Hydro's Commercial New Construction program.

Please apportion the floor space of these 'better than code, non-participating' projects by the building types you had said – in the beginning of the survey – that you had worked on.

- **For example, for the 'better than code, non-participating' floor space in 20XX, one may estimate that 80% of it is tied to hospital projects, 20% to mixed use buildings and 20% to office buildings.**

IF Q11=1: SHOW EACH GRID YEAR FOR ONLY WHERE Q23 VALUES =0-9, 98, 99

IF [(Q11=0, 99) OR Q10=0, 1)]: SHOW GRID YEARS FOR ONLY WHERE Q22 VALUES =1-99

	Projects that became occupied in 2012 ⇓	**Projects that became occupied in 2013… show other years in next columns**
Floor area of your 'better than code, non-participating' projects	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'	[CALCULATE AS FLOOR AREA SHOWN IN Q23 x VALUE OF Q24b] ft^2 IF Q22 AND/OR Q23 VALUE=99 (DON'T KNOW) THEN WRITE 'You had said Don't know to this'
Hospitals and other health care facilities [SHOW THIS ONLY IFQ3=1]	_____ %	_____ %
Grocery stores [SHOW THIS ONLY IF Q3=2]	_____ %	_____ %
Mixed-use buildings [SHOW THIS ONLY IF Q3=3]	_____ %	_____ %
Multi-unit residential buildings [SHOW THIS ONLY IF Q3=4]	_____ %	_____ %
Non-food retail stores [SHOW THIS ONLY IF Q3=5]	_____ %	_____ %
Office buildings [SHOW THIS ONLY IF Q=6]	_____ %	_____ %
Restaurants/Fast food [SHOW THIS ONLY IF Q3=7]	_____ %	_____ %
Schools [SHOW THIS ONLY IF Q3=8]	_____ %	_____ %
Universities [SHOW THIS ONLY IF Q3=9]	_____ %	_____ %
Other commercial building types	_____ %	_____ %
Your total	SHOW RUNNING	SHOW RUNNING
Target Total	**100%**	**100%**
Don't know	☐[99] Don't know	☐[99] Don't know

35. For the construction projects you worked on that are performing better than the energy efficiency requirements in the B.C. Building Code and that did not come through BC Hydro's Commercial New Construction program, how much better than the code in terms of electricity savings would you estimate these particular projects are performing?

IF Q11=1: SHOW EACH GRID YEAR FOR ONLY WHERE Q23 VALUES =0-9, 98, 99

IF [(Q11=0, 99) OR Q10=0, 1)]: SHOW GRID YEARS FOR ONLY WHERE Q22 VALUES =1-99

	Projects that became occupied in 2012 ⇓	Projects that became occupied in 2013 ⇓	Projects that became occupied in 2014 ⇓	Projects that became occupied in 2015 ⇓	Projects that became occupied in 2016 ⇓
For your project that are performing better than the energy efficiency requirements in the B.C. Building Code and did not come through the program, the percent better than the code they are performing?	☐[1] 1% - 5% better ☐[2] 6% - 9% better ☐[3] 10% better ☐[4] 20% better ☐[5] 30% better ☐[6] 40% better ☐[7] 50% + better ☐[99] Don't know	☐[1] 1% - 5% better ☐[2] 6% - 9% better ☐[3] 10% better ☐[4] 20% better ☐[5] 30% better ☐[6] 40% better ☐[7] 50% + better ☐[99] Don't know	☐[1] 1% - 5% better ☐[2] 6% - 9% better ☐[3] 10% better ☐[4] 20% better ☐[5] 30% better ☐[6] 40% better ☐[7] 50% + better ☐[99] Don't know	☐[1] 1% - 5% better ☐[2] 6% - 9% better ☐[3] 10% better ☐[4] 20% better ☐[5] 30% better ☐[6] 40% better ☐[7] 50% + better ☐[99] Don't know	☐[1] 1% - 5% better ☐[2] 6% - 9% better ☐[3] 10% better ☐[4] 20% better ☐[5] 30% better ☐[6] 40% better ☐[7] 50% + better ☐[99] Don't know

36. Intentionally left empty

37. Intentionally left empty

38. Intentionally left empty

Measures Implemented in 'Your Better than Code, Non-Participating' Projects

39.

The next set of questions is about the measures specific to your construction projects in B.C. that were completed and became occupied between 2012 and 2016, and that are performing better than the energy efficiency requirements in the B.C. Building Code but did not come through BC Hydro's Commercial New Construction program.

40. We would like to learn about the electricity conservation measures that helped your new construction projects in B.C. perform better than the energy efficiency requirements in the B.C. Building Code.

Thinking about the different types of measures for which you personally had a decision making role, what measures did you at least sometimes design or recommend to be implemented in the 'better than code, non-participating' projects?

- **Broadly consider the different types of projects that became occupied between 2012 and 2016.**

Select all that apply.

☐1 Highly-efficient heat pump recovery measures (water to water and air to water heat pumps)
☐2 Highly-efficient heat pump water heaters or low-flow fixtures
☐3 Highly-efficient building envelope measures (roof/wall Insulation, high efficiency glazing)
☐4 Highly-efficient lighting measures (includes controls and/or reduction of lighting power density)
☐5 Highly-efficient HVAC measures
☐6 Highly-efficient exhaust air heat recovery measures
☐7 Highly-efficient plug-load measures
☐8 Highly-efficient refrigeration measures
☐99 Don't know ⇒ SKIP TO Q60

ASK Q41 IF Q40=1 (HEAT PUMP RECOVERY MEASURES); ELSE SKIP TO RULE FOR Q44

41. You previously indicated that some of your projects in B.C. that did not come through BC Hydro's Commercial New Construction program incorporated highly-efficient heat pump recovery measures that helped the projects perform better than the energy efficiency requirements in the B.C. Building Code.

Thinking about all of these 'better than code, non-participating' projects collectively – those that became occupied between 2012 and 2016 – what percentage of their floor area incorporated the highly-efficient heat pump recovery measures?

☐[0] 0% (none of the floor area) ⇒ SKIP TO RULE FOR Q44
☐[2] 10%
☐[2] 20%
☐[3] 30%
☐[4] 40%
☐[5] 50%
☐[6] 60%
☐[7] 70%
☐[8] 80%
☐[9] 90%
☐[10] 100% (all of the floor area)
☐[97] At least some floor area, but don't know how much
☐[99] Don't know ⇒ SKIP TO RULE FOR Q44

42. For those projects that incorporated highly-efficient heat pump recovery measures, what heating equipment would you likely have chosen if the heat pumps were not an option?

Select all that apply.

☐[1] Natural gas boiler/packaged rooftop unit
☐[2] Electric resistance heat
☐[3] Hybrid heating source
☐[98] Other (please specify): ____________________________
☐[99] Don't know

43. For these 'better than code, non-participating' projects that incorporated highly-efficient heat pump recovery measures, what is your estimate of the electricity savings from these measures as compared to conventional measures that could have been implemented to just meet – not exceed – the energy efficiency requirements in the B.C. Building Code?

And what is your estimate of the gas savings?

Electricity Savings ⇓	Gas Savings ⇓
☐1 1% - 5% electricity savings	☐1 1% - 5% gas savings
☐2 6% - 9% electricity savings	☐2 6% - 9% gas savings
☐3 10% electricity savings	☐3 10% gas savings
☐4 20% electricity savings	☐4 20% gas savings
☐5 30% electricity savings	☐5 30% gas savings
☐6 40% electricity savings	☐6 40% gas savings
☐7 50% + electricity savings	☐7 50% + gas savings
☐99 Don't know	☐99 Don't know

ASK Q44 IF Q40=2 (HEAT PUMP DOMESTIC HOT WATER HEATING MEASURES); ELSE SKIP TO RULE FOR Q46

44. You previously indicated that some of your projects in B.C. that did not come through BC Hydro's Commercial New Construction program incorporated highly-efficient heat pump water heater or low-flow fixture measures that helped the projects perform better than the energy efficiency requirements in the B.C. Building Code.

Thinking about all of these 'better than code, non-participating' projects collectively – those that became occupied between 2012 and 2016 – what percentage of their floor area incorporated the highly-efficient heat pump water heater or low-flow fixture measures?

☐0 0% (none of the floor area) ⇒ SKIP TO RULE FOR Q46
☐1 1% - 9%
☐2 10%
☐3 20%
☐4 30%

- ☐[5] 40%
- ☐[6] 50%
- ☐[7] 60%
- ☐[8] 70%
- ☐[9] 80%
- ☐[10] 90%
- ☐[11] 100% (all of the floor area)
- ☐[98] At least some floor area, but don't know how much
- ☐[99] Don't know ⇒ SKIP TO RULE FOR Q46

45. For these 'better than code, non-participating' projects that incorporated highly-efficient heat pump domestic hot water heating measures, what is your estimate of the electricity savings from these measures as compared to the conventional measures that could have been implemented to just meet – not exceed – the energy efficiency requirements in the B.C. Building Code?

- ☐[1] 1% - 5% electricity savings
- ☐[2] 6% - 9% electricity savings
- ☐[3] 10% electricity savings
- ☐[4] 20% electricity savings
- ☐[5] 30% electricity savings
- ☐[6] 40% electricity savings
- ☐[7] 50% + electricity savings
- ☐[99] Don't know

ASK Q46 IF Q40=3 (BUILDING ENVELOPE MEASURES); ELSE SKIP TO RULE FOR Q48

46. You previously indicated that some of your projects in B.C. that did not come through BC Hydro's Commercial New Construction program incorporated highly-efficient building envelope measures that helped the projects perform better than the energy efficiency requirements in the B.C. Building Code.

Thinking about all of these 'better than code, non-participating' projects collectively – those that became occupied between 2012 and 2016 – what percentage of their floor area incorporated the highly-efficient building envelope measures?

- ☐[0] 0% (none of the floor area) ⇒ SKIP TO RULE FOR Q48
- ☐[1] 1% - 9%
- ☐[2] 10%

☐3 20%
☐4 30%
☐5 40%
☐6 50%
☐7 60%
☐8 70%
☐9 80%
☐10 90%
☐11 100% (all of the floor area)
☐98 At least some floor area, but don't know how much
☐99 Don't know ⇒ SKIP TO RULE FOR Q48

47. For these 'better than code, non-participating' projects that incorporated the highly-efficient building envelope measures, what is your estimate of the electricity savings from these measures compared to the conventional measures that could have been implemented to just meet – not exceed – the energy efficiency requirements in the B.C. Building Code?

And what is your estimate of the gas savings?

Electricity Savings ⇓	Gas Savings ⇓
☐1 1% - 5% electricity savings	☐1 1% - 5% gas savings
☐2 6% - 9% electricity savings	☐2 6% - 9% gas savings
☐3 10% electricity savings	☐3 10% gas savings
☐4 20% electricity savings	☐4 20% gas savings
☐5 30% electricity savings	☐5 30% gas savings
☐6 40% electricity savings	☐6 40% gas savings
☐7 50% + electricity savings	☐7 50% + gas savings
☐99 Don't know	☐99 Don't know

ASK Q48 IF Q40=4 (LIGHTING MEASURES); ELSE SKIP TO RULE FOR Q50

48. You previously indicated that some of your projects in B.C. that did not come through BC Hydro's Commercial New Construction program incorporated highly-efficient lighting measures that helped the projects perform better than the energy efficiency requirements in the B.C. Building Code.

Thinking about all of these 'better than code, non-participating' projects collectively – those that became occupied between 2012 and 2016 – what percentage of their floor area incorporated the highly-efficient lighting measures?

- ☐[0] 0% (none of the floor area) ⟹ SKIP TO RULE FOR Q50
- ☐[1] 1% - 9%
- ☐[2] 10%
- ☐[3] 20%
- ☐[4] 30%
- ☐[5] 40%
- ☐[6] 50%
- ☐[7] 60%
- ☐[8] 70%
- ☐[9] 80%
- ☐[10] 90%
- ☐[11] 100% (all of the floor area)
- ☐[98] At least some floor area, but don't know how much
- ☐[99] Don't know ⟹ SKIP TO RULE FOR Q50

49. For these 'better than code, non-participating' projects that incorporated the highly-efficient lighting measures, what is your estimate of the electricity savings from these measures compared to the conventional measures that could have been implemented to just meet – not exceed – the energy efficiency requirements in the B.C. Building Code?

- ☐[1] 1% - 5% electricity savings
- ☐[2] 6% - 9% electricity savings
- ☐[3] 10% electricity savings
- ☐[4] 20% electricity savings
- ☐[5] 30% electricity savings
- ☐[6] 40% electricity savings

☐[7] 50% + electricity savings
☐[99] Don't know

ASK Q50 IF Q40=5 (HVAC MEASURES); ELSE SKIP TO RULE FOR Q52

50. You previously indicated that some of your projects in B.C. that did <u>not</u> come through BC Hydro's Commercial New Construction program incorporated <u>highly-efficient HVAC measures</u> that helped the projects perform better than the energy efficiency requirements in the B.C. Building Code.

Thinking about all of these 'better than code, <u>non</u>-participating' projects collectively – those that became occupied between 2012 and 2016 – what percentage of their floor area incorporated the <u>highly-efficient HVAC measures</u>?

☐[0] 0% (none of the floor area) ⇒ SKIP TO RULE FOR Q52
☐[1] 1% - 9%
☐[2] 10%
☐[3] 20%
☐[4] 30%
☐[5] 40%
☐[6] 50%
☐[7] 60%
☐[8] 70%
☐[9] 80%
☐[10] 90%
☐[11] 100% (all of the floor area)
☐[98] At least some floor area, but don't know how much
☐[99] Don't know ⇒ SKIP TO RULE FOR Q52

51. For these 'better than code, <u>non</u>-participating' projects that incorporated the <u>highly-efficient HVAC measures</u>, what is your estimate of the <u>electricity savings</u> from these measures compared to the conventional measures that could have been implemented to just meet – not exceed – the energy efficiency requirements in the B.C. Building Code?

And what is your estimate of the <u>gas savings</u>?

Electricity Savings ⇓	**Gas Savings** ⇓
☐[1] 1% - 5% electricity savings	☐[1] 1% - 5% gas savings
☐[2] 6% - 9% electricity savings	☐[2] 6% - 9% gas savings
☐[3] 10% electricity savings	☐[3] 10% gas savings
☐[4] 20% electricity savings	☐[4] 20% gas savings
☐[5] 30% electricity savings	☐[5] 30% gas savings
☐[6] 40% electricity savings	☐[6] 40% gas savings
☐[7] 50% + electricity savings	☐[7] 50% + gas savings
☐[99] Don't know	☐[99] Don't know

ASK Q52 IF Q0=6 (EXHAUST AIR HEAT RECOVERY MEASURES); ELSE SKIP TO RULE FOR Q54

52. You previously indicated that some of your projects in B.C. that did <u>not</u> come through BC Hydro's Commercial New Construction program incorporated <u>highly-efficient exhaust air heat recovery measures</u> that helped the projects perform better than the energy efficiency requirements in the B.C. Building Code.

Thinking about all of these 'better than code, <u>non</u>-participating' projects collectively – those that became occupied between 2012 and 2016 – what percentage of their floor area incorporated the <u>highly-efficient exhaust air heat pump recovery measures</u>?

☐[0] 0% (none of the floor area) ⇒ SKIP TO RULE FOR Q54
☐[1] 1% - 9%
☐[2] 10%
☐[3] 20%
☐[4] 30%
☐[5] 40%
☐[6] 50%
☐[7] 60%
☐[8] 70%
☐[9] 80%
☐[10] 90%

☐[11] 100% (all of the floor area)
☐[98]At least some floor area, but don't know how much
☐[99] Don't know ⇒ SKIP TO RULE FOR Q54

53. For these 'better than code, non-participating' projects that incorporated the highly-efficient exhaust air heat recovery measures, what is your estimate of the electricity savings from these measures compared to the conventional measures that could have been implemented to just meet – not exceed – the energy efficiency requirements in the B.C. Building Code?

And what is your estimate of the gas savings?

Electricity Savings ⇓	Gas Savings ⇓
☐[1] 1% - 5% electricity savings	☐[1] 1% - 5% gas savings
☐[2] 6% - 9% electricity savings	☐[2] 6% - 9% gas savings
☐[3] 10% electricity savings	☐[3] 10% gas savings
☐[4] 20% electricity savings	☐[4] 20% gas savings
☐[5] 30% electricity savings	☐[5] 30% gas savings
☐[6] 40% electricity savings	☐[6] 40% gas savings
☐[7] 50% + electricity savings	☐[7] 50% + gas savings
☐[99] Don't know	☐[99] Don't know

ASK Q54 IF Q40=7 (PLUG LOAD MEASURES); ELSE SKIP TO RULE FOR Q56

54. You previously indicated that some of your projects in B.C. that did not come through BC Hydro's Commercial New Construction program incorporated highly-efficient plug-load measures that helped the projects perform better than the energy efficiency requirements in the B.C. Building Code.

Thinking about all of these 'better than code, non-participating' projects collectively – those that became occupied between 2012 and 2016 – what percentage of their floor area incorporated the highly-efficient plug-load measures?

- ☐[0] 0% (none of the floor area) ⇒ SKIP TO RULE FOR Q56
- ☐[1] 10%
- ☐[2] 20%
- ☐[3] 30%
- ☐[4] 40%
- ☐[5] 50%
- ☐[6] 60%
- ☐[7] 70%
- ☐[8] 80%
- ☐[9] 90%
- ☐[10] 100% (all of the floor area)
- ☐[97] At least some floor area, but don't know how much
- ☐[99] Don't know ⇒ SKIP TO RULE FOR Q56?

55. For these 'better than code, non-participating' projects that incorporated the highly-efficient plug-load measures, what is your estimate of the electricity savings from these measures compared to the conventional measures that could have been implemented to just meet – not exceed – the energy efficiency requirements in the B.C. Building Code?

- ☐[1] 1% - 5% electricity savings
- ☐[2] 6% - 9% electricity savings
- ☐[3] 10% electricity savings
- ☐[4] 20% electricity savings
- ☐[5] 30% electricity savings
- ☐[6] 40% electricity savings
- ☐[7] 50% + electricity savings
- ☐[99] Don't know

ASK Q56 IF Q40=8 (REFRIGERATION MEASURES); ELSE SKIP TO Q60

56. You previously indicated that some of your projects in B.C. that did not come through BC Hydro's Commercial New Construction program incorporated highly-efficient refrigeration measures that helped the projects perform better than the energy efficiency requirements in the B.C. Building Code.

Thinking about all of these 'better than code, non-participating' projects collectively – those that became occupied between 2012 and 2016 – what percentage of their floor area incorporated the highly-efficient refrigeration measures?

- ☐[0] 0% (none of the floor area) ⇒ SKIP TO Q60
- ☐[1] 1% - 9%
- ☐[2] 10%
- ☐[3] 20%
- ☐[4] 30%
- ☐[5] 40%
- ☐[6] 50%
- ☐[7] 60%
- ☐[8] 70%
- ☐[9] 80%
- ☐[10] 90%
- ☐[11] 100% (all of the floor area)
- ☐[98] At least some floor area, but don't know how much
- ☐[99] Don't know ⇒ SKIP TO Q60

57. For these 'better than code, non-participating' projects that incorporated the highly-efficient refrigeration measures, what is your estimate of the electricity savings from these measures compared to the conventional measures that could have been implemented to just meet – not exceed – the energy efficiency requirements in the B.C. Building Code?

- ☐[1] 1% - 5% electricity savings
- ☐[2] 6% - 9% electricity savings
- ☐[3] 10% electricity savings
- ☐[4] 20% electricity savings
- ☐[5] 30% electricity savings
- ☐[6] 40% electricity savings
- ☐[7] 50% + electricity savings
- ☐[99] Don't know

58. Intentionally left empty

59. Intentionally left empty

Drivers of Your 'Better than Code, Non-Participating' Projects

ASK Q60 IF [(Q10=2, 1) AND/OR (Q12=1) AND/OR (Q13=1)]; ELSE SKIP TO Q63

60. Consider your new construction projects in B.C. – that became occupied from 2012 to 2016 – that are performing better than the energy efficiency requirements in the B.C. Building Code and that did not come through BC Hydro's Commercial New Construction program.

What 'drivers' do you credit for making these particular projects perform even better than the energy efficiency requirements in the B.C. Building Code?

Please record the percent shares you would credit each 'driver' such that they total 100 percent.

	Projects that became occupied from 2012 - 2016 ⇓
BC Hydro Drivers	
My learnings and experience from having had other projects go through BC Hydro's Commercial New Construction program (previously, the High Performance Buildings program) [SHOW ONLY IFQ10=2]	_________
My learnings and experience from having attended BC Hydro workshops [SHOW ONLY IF Q12=1]	_________
My learnings from having reviewed the case studies and resource literature posted on BC Hydro's website [SHOW ONLY IF Q13=1]	_________
My learnings from having reviewed the Building Envelope Thermal Bridging Guide [SHOW ONLY IF Q15=1]	_________
My learnings from having reviewed the Enhanced Thermal Performance Spreadsheet [SHOW ONLY IF Q16=1]	_________
Non-BC Hydro Drivers	
Industry innovation and good practices (outside of BC Hydro involvement)	_________
My own or my organization's desire to build such projects for LEED certification	_________
My/our client directed us to have such projects perform better than the energy efficiency requirements in the B.C. Building Code	_________
All other factors	_________
Your Total (SHOW RUNNING TOTAL)	XX%
Target Total	100%

61. Consider your new construction projects in B.C. – that became occupied from 2012 to 2016 – that are performing better than the energy efficiency requirements in the B.C. Building Code and that did not come through BC Hydro's Commercial New Construction program.

Which one of the following statements best describes what the energy efficiency of those non-participating projects would have been had you NOT – nor any of your colleagues…

SHOW AS BULLETS:

SHOW IF A PAST PARTICIPANT [Q10=2]: **had any prior experience with the Commercial New Construction program**

SHOW IF ATTENDED A WORKSHOP [Q12=1]: **ever attended any of BC Hydro's workshops on commercial new construction**

SHOW IF REVIEWED CASE STUDIES [Q13=1]: **ever reviewed any case studies or resource literature on BC Hydro's website**

SHOW IF REVIEWED THERMAL BRIDGING GUIDE [Q15=1]: **ever reviewed the Building Envelope Thermal Bridging Guide**

SHOW IF REVIEWED ENERGY MODELLING GUIDELINES [Q16=1]: **ever reviewed the Enhanced Thermal Performance Spreadsheet**

☐1 These projects would likely still be performing better than the energy efficiency requirements in the B.C. Building Code by the same margin.

☐2 These projects would likely be performing better than the energy efficiency requirements in the B.C. Building Code, but by a smaller margin.

☐3 These projects would likely be meeting the energy efficiency requirements in the B.C. Building Code.

☐4 These projects would likely be performing worse than the energy efficiency requirements in the B.C. Building Code.

☐99 Don't know

☐97 Not applicable – the interaction(s) occurred after the design decisions were made for these projects.

62. Consider each of the following experiences and 'touchpoints' you have had with BC Hydro in regards to commercial new construction:

SHOW AS BULLETS:

SHOW IF A PAST PARTICIPANT [Q10=2]: **your learnings and experience from having worked on 'participating projects' that came through the Commercial New Construction program**

SHOW IF ATTENDED A WORKSHOP [Q12=1]: **your learnings and experience from having attended BC Hydro's workshops on commercial new construction**

SHOW IF REVIEWED CASE STUDIES [Q13=1]: **your learnings and experience from having reviewed case studies or resource literature on BC Hydro's website**

SHOW IF REVIEWED THERMAL BRIDGING GUIDE [Q15=1]: **your learnings and experience from having reviewed the Building Envelope Thermal Bridging Guide**

SHOW IF REVIEWED ENERGY MODELLING GUIDELINES [Q16=1]: **your learnings and experience from having reviewed the Enhanced Thermal Performance Spreadsheet**

Overall, how influential were these experiences and 'touchpoints' on your decisions to have '<u>non</u>-participating projects' that became occupied from 2012 to 2016 – those that did <u>not</u> come through the program – designed to perform better than the energy efficiency requirements in the B.C. Building Code?

☐[1] Very influential

☐[2] Somewhat influential

☐[3] Not too influential

☐[4] Not at all influential

☐[99] Don't know

☐[97] Not applicable – the interaction(s) occurred after the design decisions were made for these projects.

Industry Evolution

63. Compared to buildings that became occupied say 2005 - 2011, to what extent do you believe the entire commercial new construction market in the province has improved in terms of the energy use of the projects that became occupied in 2012 - 2016?

- ☐[0] 0% - no better ⇒ SKIP TO Q65
- ☐[1] 1% - 9% better
- ☐[2] 10% better
- ☐[3] 20% better
- ☐[4] 30% better
- ☐[5] 40% better
- ☐[6] 50% + better ⇒ SKIP TO Q65

64. Thinking about your response to the previous question, how much of the improvement in the commercial new construction energy use in the province – for projects that became occupied in 2012 - 2016 as compared to those that became occupied in 2005 - 2011 – would you attribute to BC Hydro's Commercial New Construction program (previously, the High Performance Buildings program)?

- ☐[0] 0% of the improved energy use is attributable to BC Hydro's program
- ☐[1] 1% - 9%
- ☐[2] 10%
- ☐[3] 20%
- ☐[4] 30%
- ☐[5] 40%
- ☐[6] 50% + of the improved energy use is attributable to BC Hydro's program
- ☐[99] Don't know

65. Think about all of the commercial new construction projects in B.C. from 2012 to 2016 for which you had any sort of decision making role regarding the extent that the projects would be energy efficient – regardless of whether or not they came through BC Hydro's Commercial New Construction program.

How much electricity would you say those projects are saving relative to the energy efficiency requirements in the B.C. Building Code?

- ☐0 0% electricity savings (the projects would be performing to the energy efficiency requirements in the B.C. Building Code)
- ☐1 1% - 9% electricity savings better than the energy efficiency requirements in the B.C. Building Code
- ☐2 10% electricity savings better than the energy efficiency requirements in the B.C. Building Code
- ☐3 20% electricity savings better than the energy efficiency requirements in the B.C. Building Code
- ☐4 30% electricity savings better than the energy efficiency requirements in the B.C. Building Code
- ☐5 40% electricity savings better than the energy efficiency requirements in the B.C. Building Code
- ☐6 50% + electricity savings better than the energy efficiency requirements in the B.C. Building Code
- ☐99 Don't know

66. What's your impression of all other commercial new construction projects in the province from 2012 to 2016? (those you were <u>not</u> involved in)

How much electricity would you say those projects are saving relative to the energy efficiency requirements in the B.C. Building Code?

- ☐0 0% electricity savings (the projects would be performing to the energy efficiency requirements in the B.C. Building Code)
- ☐1 1% - 9% electricity savings better than the energy efficiency requirements in the B.C. Building Code
- ☐2 10% electricity savings better than the energy efficiency requirements in the B.C. Building Code
- ☐3 20% electricity savings better than the energy efficiency requirements in the B.C. Building Code
- ☐4 30% electricity savings better than the energy efficiency requirements in the B.C. Building Code
- ☐5 40% electricity savings better than the energy efficiency requirements in the B.C. Building Code
- ☐6 50% + electricity savings better than the energy efficiency requirements in the B.C. Building Code
- ☐99 Don't know

Your Confidence in Your Responses

67. It is very much appreciated that because most of the questions in this survey pertain to your commercial new construction projects that became occupied several years ago, it may have been difficult to remember the projects – in their collectivity – and to have provided various estimates about them.

Overall, how much confidence would you say you have in the accuracy of the various estimates you gave in this survey?

☐[0] 0% confidence
☐[1] 10%
☐[2] 20%
☐[3] 30%
☐[4] 40%
☐[5] 50%
☐[6] 60%
☐[7] 70%
☐[8] 80%
☐[9] 90%
☐[10] 100% confidence ⇒ SKIP TO Q69
☐[99] Don't know

68. Which of the following areas of the survey would you say you are generally confident about in your estimates?

Which of the areas would you say you are <u>not</u> confident about in your estimates?

	Confident	Not Confident	Don't know
The type of buildings that became occupied from 2012 to 2016 for which you played a design decision role.	☐1	☐0	☐99
Your estimates of the floor area of your project in B.C. that became occupied from 2012 to 2016.	☐1	☐0	☐99
Your estimates of the percent of floor area of your projects that are performing better than the energy efficiency requirements in the B.C. Building Code.	☐1	☐0	☐99
Your estimates of the percent of floor area of your 'better than code' projects that came through BC Hydro's Commercial New Construction Program. [SHOW ONLY IF Q11=1]	☐1	☐0	☐99
The various electricity conservation measures you designed or recommended in your 'highly performing, non-participating' projects.	☐1	☐0	☐99
The percent of floor area of your 'highly performing, non-participating' projects that incorporated these conservation measures.	☐1	☐0	☐99
Your estimates of the electricity savings from each of these conservation measures.	☐1	☐0	☐99
Your credit(s) to BC Hydro on their influence on the commercial new construction industry in B.C.	☐1	☐0	☐99

Your Project Names

69. A large number and wide variety of professionals within the commercial new construction industry have been invited to participate in this survey. In an effort to further understand the sample composition of completed surveys, it would be beneficial to learn the names of the 3 largest projects in B.C. that you worked on – those that became occupied from 2012 to 2016.

- **Only list those new construction projects in B.C. – that became occupied from 2012 to 2016 – that are performing better than the energy efficiency requirements in the B.C. Building Code and that did not come through BC Hydro's Commercial New Construction program.**
- **To ensure clarity, also indicate each project's building types (e.g. hospital, grocery store, office building, etc.)**
- **In BC Hydro's reporting, none of your earlier responses in this survey will be linked to the names of the projects that you list below.**

	Project Name ⇓	Project building type ⇓
Project 1		
Project 2		
Project 3		

Thank You

SHOW Q70 ONLY IF [(Q1=0, 99) OR (Q2=3, 99) OR (Q3=99)]; ELSE SKIP TO Q71

70. Thank you for your willingness to complete this survey, however, based on your responses, you aren't in this study's target population of interest. Please advance to the next page to enter your name into the prize draw

Incentive Prize Draw

71. Please provide your name and contact information below if you wish to be entered into the draw for one of four $250 gift cards to a home improvement retailer of your choice. You can view the official rules and regulations here.

	Name:	Telephone:	Email Address:
☐[1] Yes ⇒	____________________	____________	________________________
☐[0] No thanks			

Appendix F Participant Survey – Questionnaire

BC Hydro
Power smart

Commercial New Construction Survey (Wave 5 – May 2016)

INTRODUCTION TEXT

Thank you for taking the time to complete this survey.

Commercial New Construction Program (umbrella program name) Participants: Survey IDs 500,000 – 528,999

Our records indicate that your organization's site located at (insert service address, service town) **participated in BC Hydro's** (insert umbrella program name as per survey ID) **between (DATEflag=1 "October 2015 and March 2016"; DATEflag=2, "April and October 2015"). We are interested in your organization's experience with the program and would appreciate your feedback. If you feel that this survey should be completed by another individual at your organization, please forward the original email invitation to that person. In recognition of your time and effort to complete this survey you will receive a $50 gift certificate upon completing and submitting the survey.**

In consideration of privacy issues, do not self-identify (unless for the purposes of receiving the gift card) or identify other specific individuals in your written comments. Any comments including self-identification or identification of third parties will be discarded.

About You

1. Which of the following best describes your position/title within the organization? Check one only.

- ☐1 Operations or maintenance manager
- ☐2 Operations or maintenance technician/engineer
- ☐3 Plant manager
- ☐4 Business owner or co-owner
- ☐5 Executive
- ☐6 Site or property manager/supervisor
- ☐7 General manager
- ☐8 Energy Manger – hired as part of BC Hydro's Energy Manager program
- ☐9 Energy Manager – NOT hired as part of BC Hydro's Energy Manager program
- ☐10 Finance manager
- ☐11 Purchasing manager
- ☐12 Accountant/Bookkeeper
- ☐13 Developer
- ☐14 Project Manager
- ☐16 Strata council member
- ☐15 Other: please specify __________________

2. For each of the following, please indicate whether you are primarily or jointly responsible for decision making in relation to this particular site, whether someone else at the site is responsible, or whether the decision making is made by a person or team away from the site such as at a corporate office.

		Yes, I am the primary or joint decision maker	No, someone else at this site is the decision maker	No, someone else away from this site is the decision maker	Don't know
a.	Decisions related to investments in equipment costing <u>less than $100,000</u>	☐[1]	☐[2]	☐[3]	☐[999]
b.	Decisions related to investments in equipment costing <u>$100,000 or more</u>	☐[1]	☐[2]	☐[3]	☐[999]
c.	Decisions related to energy management	☐[1]	☐[2]	☐[3]	☐[999]
d.	Decisions related to the maintenance of equipment	☐[1]	☐[2]	☐[3]	☐[999]
e.	Decisions related to capital investments in retrofitting existing sites/facilities or building new sites/facilities	☐[1]	☐[2]	☐[3]	☐[999]
f.	Decisions related to the operation and maintenance of sites/facilities	☐[1]	☐[2]	☐[3]	☐[999]

About this Site

3. Which of the following best describes the ownership of this organization?

- ☐1 Government or public sector (e.g., schools, hospitals, universities, etc.)
- ☐2 Non-governmental organization (e.g,, non-profit, strata council, etc.)
- ☐3 For profit (e.g., publically owned, privately owned, franchise, chain, etc.)
- ☐4 Other: please specify _________________
- ☐999 Don't know/Not sure

4. Please check the one box corresponding to your organization's primary business activity at this particular site. Check one only.

- ☐2 Apartment building or strata property
- ☐3 Arts/entertainment/film
- ☐4 Automotive
- ☐5 Banking/finance/insurance
- ☐6 Business or personal services
- ☐7 Camps/recreation/sports/amusement
- ☐8 College
- ☐9 Communications/media
- ☐10 Construction/home & building contractors
- ☐11 Development/real estate/commercial property management
- ☐12 Food & beverage production or storage
- ☐13 Forest products or wood processing
- ☐14 Government – Local/Provincial/Federal
- ☐15 Hospital (including care facilities)
- ☐16 Hospitality/lodging/tourism
- ☐26 Mixed-use building (e.g., mixed commercial/residential units, etc.)
- ☐28 Retail – non-food
- ☐29 Retail – food stores
- ☐30 Restaurants and food service
- ☐31 Religious organization
- ☐32 School (public or private)
- ☐33 Social services
- ☐35 Transportation
- ☐36 University
- ☐38 Warehousing
- ☐39 Wholesale and Distribution
- ☐40 Other: please specify______________

Awareness of BC Hydro's CNC Program

7b. [For CNC, ask Q29 and Q30 first, then skip back to Q7b] Where did you hear about this program? Select all that apply. [do not randomize]

☐[1] Advertising
☐[2] Direct Mail
☐[3] Email
☐[4] Power of Business Newsletter
☐[5] Current Newsletter
☐[6] Media news story
☐[7] BC Hydro website
☐[8] Other website
☐[9] Facebook or Twitter
☐[10] BC Hydro Key Account Manager
☐[11] BC Hydro Engineering
☐[12] BC Hydro Alliance of Energy Professionals member (formerly Power Smart Alliance)
☐[13] Industry colleagues
☐[14] Work colleagues
☐[15] Friends and family
☐[16] Other, please specify: (*please do not identify individuals by name, title or organization)*
☐[999] Don't know

7c. Please complete the following sentence, 'My business was interested in BC Hydro's (insert umbrella program as per survey ID) because we wanted to …' Select all that apply. [randomize1 to 6]

☐[1] "Green" the business
☐[2] Decrease operating costs
☐[3] Receive incentives
☐[4] Implement energy efficiency technology at the business
☐[5] Improve the lighting at the business
☐[6] Improve the comfort at the business
☐[7] Other reason, please specify: (*please do not identify individuals by name, title or organization)*
☐[999] Don't know

Commercial New Construction Program

29. In the last two years, has your organization completed a major renovation or expansion to an existing facility or built a new facility either at this location or at another location? Check all that apply.

- ☐[1] Yes, we have renovated or expanded an existing facility and/or built a new facility either at this location or at another location in the last two years
- ☐[2] We are currently in the process of renovating or expanding an existing facility and/or building a new facility at this location or at another location
- ☐[3] No
- ☐[999] Don't know

30. BC Hydro's Commercial New Construction Program provides funding and design expertise to eligible customers who are building new facilities, doing a major renovation or expanding existing ones. The program starts with a fully-funded comprehensive energy study which determines a site's energy baseline followed by a range of design options and financial incentives to implement the energy conservation measures and improve its efficiency.

`Prior to this survey, had you heard of BC Hydro's Commercial New Construction Program?

- ☐[1] Yes ⇒ SURVEY IDS 500,000-528,999 SKIP BACK TO Q7b AND Q7c; THEN RETURN TO Q31
- ☐[2] No ⇒ SKIP TO Q40
- ☐[999] Don't know SKIP TO Q40

31. The Commercial New Construction Program pays up to 100% of an energy study which can help customers understand their design options for a new or expanded facility/site and how energy-efficient designs will help them save energy and money over a theoretical baseline.

Prior to receiving this survey, were you aware of the basics of the Energy Study component of the Commercial New Construction Program?

- ☐[1] Yes ⇒ CONTINUE TO Q32
- ☐[2] No ⇒ SKIP TO Q34
- ☐[999] Don't know ⇒ SKIP TO Q34

32. Prior to receiving this survey, how would you rate your understanding of the Energy Study component of the Commercial New Construction Program?

- ☐[1] Excellent
- ☐[2] Good
- ☐[3] Fair
- ☐[4] Poor
- ☐[5] Very Poor
- ☐[999] Don't know

33. Overall, how would you rate the Energy Study component of the Commercial New Construction Program?

☐1 Excellent
☐2 Good
☐3 Fair
☐4 Poor
☐5 Very Poor
☐999 Don't know

34. The Commercial New Construction Program provides financial incentives that reduce the incremental costs (i.e., those costs that exceed the costs for standard, inefficient design options) of energy efficiency measures, or bundle of measures, related to building new facilities or renovating existing ones, up to a maximum of $500,000.

Prior to receiving this survey, were you aware of the basics of the Project Incentive structure of the Commercial New Construction Program?

☐1 Yes ⇒ CONTINUE TO Q35
☐2 No ⇒ SKIP TO Q40
☐999 Don't know ⇒ SKIP TO Q40

35. Prior to receiving this survey, how would you rate your understanding of the Project Incentive structure of the Commercial New Construction Program?

☐1 Excellent
☐2 Good
☐3 Fair
☐4 Poor
☐5 Very Poor
☐999 Don't know

36. Overall, how would you rate the Project Incentive structure of the Commercial New Construction Program?

☐1 Excellent
☐2 Good
☐3 Fair
☐4 Poor
☐5 Very Poor
☐999 Don't know ⇒ ALL SKIP TO Q40

Program Components: Key Account Manager

40. (Only ask if KAMflag=1; otherwise skip to Q44) A Key Account Manager is an organization's point-person inside BC Hydro who is responsible for managing various aspects of the customer relationship. This may include aspects relating to rates, outages, etc., but also those aspects relating to energy efficiency and conservation.

Prior to receiving this survey, were you aware of Key Account Managers?

☐[1] Yes ⇒ CONTINUE TO Q41
☐[2] No ⇒ SKIP TO Q44
☐[999] Don't know ⇒ SKIP TO Q44

41. Prior to receiving this survey, were you aware that the Key Account Manager acts as a liaison between BC Hydro's (insert umbrella program as per survey ID) and its participants?

☐[1] Yes ⇒ CONTINUE TO Q42
☐[2] No ⇒ SKIP TO Q44
☐[999] Don't know ⇒ SKIP TO Q44

42. Prior to receiving this survey, how would you rate your understanding of the role of the Key Account Manager in relation to BC Hydro's (insert umbrella program as per survey ID)?

☐[1] Excellent
☐[2] Good
☐[3] Fair
☐[4] Poor
☐[5] Very Poor
☐[999] Don't know

43. Overall, how would you rate your organization's Key Account Manager in relation to their support of your participation in BC Hydro's (insert umbrella program as per survey ID)?

- ☐1 Excellent
- ☐2 Good
- ☐3 Fair
- ☐4 Poor
- ☐5 Very Poor
- ☐999 Don't know
- ☐998 Not applicable – I have had no experience with a Key Account Manager in regards to the program

Program Component: BC Hydro Alliance of Energy Professionals (ALL SURVEY IDs)

The BC Hydro Alliance of Energy Professionals (formerly Power Smart Alliance) is a network of independent contractors and engineers that can help you select, install and maintain your site's energy related equipment.

44. Were you aware of the BC Hydro Alliance of Energy Professionals (formerly Power Smart Alliance) before this survey?

- ☐1 Yes ⇒ CONTINUE TO Q45
- ☐2 No ⇒ SKIP TO RULE FOR Q45b
- ☐999 Don't know => SKIP TO RULE FOR Q45b

45. Has a BC Hydro Alliance of Energy Professionals partner contacted your organization regarding BC Hydro's (insert program as per survey ID)?

- ☐1 Yes
- ☐2 No
- ☐999 Don't know

Your Site's Participation in BC Hydro's (insert umbrella program as per survey ID)

46. (FOR FIRST PROJECT THAT RESPONDENT IS SEEING) **As first mentioned at the beginning of this survey, BC Hydro records indicate that energy-efficient measures were implemented and/or technologies were installed at** (insert service address; service town) **through your organization's participation in BC Hydro's (insert umbrella program as per survey ID). Below is a project completed with the assistance of the program between** (DATEflag=1, "October 2015 and March 2016"; DATEflag=2, "April and September 2015")**.**

(FOR ANY ADDITONAL PROJECTS) **Here is another project completed with the assistance of BC Hydro's** (insert umbrella program as per survey ID) **at** (insert service address; service town) **between** (DATEflag=1, "October 2015 and March 2016"; DATEflag=2, "April and September 2015").

Were you generally aware of the project listed below?

Type of Assistance:	(insert assistance name)
Brief Project Description:	(insert brief project description)
Incentive amount paid by CNC	(insert incentive amount)

☐[1] Yes, I was generally aware of this project
☐[2] No, I was not aware of this project
☐[999] Don't know

⇒NB: Question repeated for each project completed at the site level up to a maximum of 3 projects (e.g., if 3 separate projects completed at the site level, then questions Q47 to Q54 get repeated as Q47-2 to Q54-2 and Q47-3 to Q54-3 with the descriptions of each project shown)

⇒IF "DON'T KNOW" OR "NO" FOR ALL, THEN SKIP TO Q57. OTHERWISE IF "NO" TO A PROJECT, SKIP TO FOLLOWING PROJECT IF MORE THAN 1 PROJECT.

⇒IF "YES" FOR ANY PROJECT SHOWN THEN CONTINUE THROUGH Q47 TO Q54.

47. For the project listed below…

(ONLY INCLUDE THOSE PROJECTS THAT HAVE BEEN SELECTED 'YES' IN Q46 ABOVE)

Type of Assistance:	(insert assistance name)
Brief Project Description:	(insert brief project description)
Incentive amount paid by CNC	(insert incentive amount)

…if the assistance from BC Hydro's (insert umbrella program name as per survey ID) had not existed, would your organization have completed the project…

☐1 …at about the same time as actually done so
☐2 …within a year of when actually done so
☐3 …more than a year but less than 3 years later
☐4 …more than 3 years later
☐5 My organization would have completed this project, but I am unsure about the timing
☐6 My organization would NOT have completed this project (⇒ CONTINUE TO Q48)
☐999 Don't know

⇒ ANSWERS 1-5 AND 99 SKIP TO Q49.

⇒ Q48 IS ASKED FOR A PROJECT ONLY IF THE CORRESPONDING Q47 IS 6 "MY ORGANIZATION WOULD NOT HAVE COMPLETED THIS PROJECT"

48. Why would your organization NOT have completed this project? (In consideration of privacy issues, please do not reference any individuals' names.) (OPEN END)

☐0 No comments

SKIP TO Q54

49. For the project listed below… (ONLY INCLUDE THOSE PROJECTS THAT HAVE BEEN SELECTED 'YES' IN Q46 ABOVE)

Type of Assistance:	(insert assistance name)
Brief Project Description:	(insert brief project description)
Incentive amount paid by CNC	(insert incentive amount)

…which of the following three statements best describes the energy efficiency of the measure that would have been installed at (insert service address, service town) if the assistance provided by BC Hydro's (insert umbrella program name as per survey ID) had not existed?

- ☐1 We would have completed this measure with a LOWER ENERGY EFFICIENCY than actually installed
- ☐2 We would have completed this measure with the SAME ENERGY EFFICIENCY as actually installed
- ☐3 We would have completed this measure with a HIGHER ENERGY EFFICIENCY than actually installed
- ☐999 Don't know
- ☐998 Not applicable

50. For the project listed below… (ONLY INCLUDE THOSE PROJECTS THAT HAVE BEEN SELECTED 'YES' IN Q46 ABOVE)

Type of Assistance:	(insert assistance name)
Brief Project Description:	(insert brief project description)
Incentive amount paid by CNC	(insert incentive amount)

…what percentage of this project would your organization have completed on its own if the assistance from BC Hydro's (insert umbrella program name as per survey ID) had not existed?

When considering your answer, please keep in mind all the equipment, all the technologies, and/or all of the sites included in this project.

You may either enter a percentage in the field provided, or choose from the list provided:

OR:

☐1 0%	☐2 1% to 24%	☐3 25% to 49%	☐4 50% to 74%	☐5 75% to 99%
☐6 100% or greater	☐999 Don't know			
☐988 Not applicable				

51. For the project listed below… (ONLY INCLUDE THOSE PROJECTS THAT HAVE BEEN SELECTED 'YES' IN Q46 ABOVE)

Type of Assistance:	(insert assistance name)
Brief Project Description:	(insert brief project description)
Incentive amount paid by CNC	(insert incentive amount)

…had there been no financial incentive from BC Hydro (i.e., money paid directly from BC Hydro to your organization – which does not include money for energy audits, studies or Energy Managers – would the energy-efficient measure have met your organization's financial criteria around site investments?

☐[1] Yes, it would have met our financial criteria
☐[2] No, it would NOT have met our financial criteria
☐[999] Don't know
☐[998] Not Applicable

52. For the project listed below… (ONLY INCLUDE THOSE PROJECTS THAT HAVE BEEN SELECTED 'YES' IN Q46 ABOVE)

Type of Assistance:	(insert assistance name)
Brief Project Description:	(insert brief project description)
Incentive amount paid by CNC	(insert incentive amount)

…was the idea to implement the energy efficiency measure first suggested through BC Hydro assistance, such as a BC Hydro-funded energy consultant, BC Hydro-funded Energy Manager or a BC Hydro representative?

☐[1] Yes, the idea was first suggested through BC Hydro assistance.
☐[2] No, the idea was NOT first suggested through BC Hydro assistance
☐[999] Don't know

53. For the project listed below… (ONLY INCLUDE THOSE PROJECTS THAT HAVE BEEN SELECTED 'YES' IN Q46 ABOVE)

Type of Assistance:	(insert assistance name)
Brief Project Description:	(insert brief project description)
Incentive amount paid by CNC	(insert incentive amount)

…how much experience did your organization have with this type of energy-efficient measure that was implemented and/or technology that was installed, previous to your site's participation in BC Hydro's (insert umbrella program as per survey ID)?

☐[1] A great deal of experience

☐[2] A fair amount of experience

☐[3] A little experience

☐[4] No experience at all

☐[999] Don't know

54. For the project listed below… (ONLY INCLUDE THOSE PROJECTS THAT HAVE BEEN SELECTED 'YES' IN Q46 ABOVE)

Type of Assistance:	(insert assistance name)
Brief Project Description:	(insert brief project description)
Incentive amount paid by CNC	(insert incentive amount)

…overall, how influential was BC Hydro's (insert umbrella program as per survey ID) on your organization's decision to implement the energy-efficient measure listed above at this site?

☐[1] Very influential

☐[2] Somewhat influential

☐[3] Not too influential

☐[4] Not at all influential

☐[999] Don't know

Additional Site Investments in Energy Efficiency (ALL SURVEY IDs)

57. Since participating in BC Hydro's (insert umbrella program as per survey ID) for the projects listed below," and no further back than April 2015, has the site at (insert service address, service town) implemented any new energy-efficient measures and/or installed any new energy-efficient technologies without assistance from BC Hydro, or have plans in place to do so within the next two years? We mean something that is more significant than installing a new light bulb. We're looking for HVAC improvements, lighting retrofits, installation of lighting controls, building shell improvements, etc.

- ☐[1] Yes, additional energy efficiency measures have been made and /or will be made at this site without the assistance from BC Hydro ⇒ CONTINUE TO Q58
- ☐[2] No additional significant energy efficiency measures have been made at this site ⇒ SKIP TO Q68
- ☐[999] Don't know / not sure ⇒ SKIP TO Q68

(IF "TYPE OF ASSISTANCE" AND "BRIEF PROJECT DESCRIPTION" ARE POPULATED IN Q46, THEN SHOW FOLLOWING TEXT AND TABLE)

AS A REMINDER …

Please exclude the following projects which your organization completed with BC Hydro's (insert umbrella program as per survey ID)

Type of Assistance	Brief Project Details
(insert assistance name)	(insert brief project description)
(insert assistance name)	(insert brief project description)
(insert assistance name)	(insert brief project description)

58. Which of the following areas or components (if any) of your site located at (insert service address, service town) have been improved or do you have plans to improve within the next 2 years without assistance from BC Hydro? We mean something that is more significant than installing a new light bulb. We're looking for HVAC improvements, lighting retrofits, installation of lighting controls, building envelope improvements, for a new or expanded site/facility, etc. Check all that apply.

			Have been improved	Have plans to improve within the next 2 years
a.	New lighting systems, components, or controls	→	☐1	☐1
b.	New cooling systems, components or controls	→	☐2	☐2
c.	New heating systems, components or controls	→	☐3	☐3
d.	New technologies for process cooling	→	☐4	☐4
e.	New motors or pumps	→	☐5	☐5
f.	New motor drive systems	→	☐6	☐6
g.	New technologies for compressed air	→	☐7	☐7
h.	New technologies for material conveyors	→	☐8	☐8
i.	New compressed air systems	→	☐9	☐9
j.	New technologies for fans	→	☐10	☐10
k.	New refrigeration systems, components or controls	→	☐11	☐11
l.	New technologies for energy management control/software	→	☐12	☐12
m.	New technologies for water heating	→	☐13	☐13
n.	New technologies for computers, IT and office equipment	→	☐14	☐14
o.	Building envelope measures/improvements	→	☐15	☐15
p.	Other: please specify___________________________	→	☐16	☐16
q.	None of the above ⇒ SKIP TO Q68	→	☐17	☐17

⇒ IF "YES" FOR ANY OF 'A' TO 'O' THEN CONTINUE TO Q59

59. For each item that you have improved or will improve, did or will this site install any of these items due to a program offered by another organization such as a gas company, provincial or federal government? (INSERT ONLY THOSE ITEMS SLECTED FROM Q58).

		Yes	No	Don't know
a. New lighting systems, components, or controls	→	☐1	☐2	☐999
b. New cooling systems, components or controls	→	☐1	☐2	☐999
c. New heating systems, components or controls	→	☐1	☐2	☐999
d. New technologies for process cooling	→	☐1	☐2	☐999
e. New motors or pumps	→	☐1	☐2	☐999
f. New motor drive systems	→	☐1	☐2	☐999
g. New technologies for compressed air	→	☐1	☐2	☐999
h. New technologies for material conveyors	→	☐1	☐2	☐999
i. New compressed air systems	→	☐1	☐2	☐999
j. New technologies for fans	→	☐1	☐2	☐999
k. New refrigeration systems, components or controls	→	☐1	☐2	☐999
l. New technologies for energy management control/software	→	☐1	☐2	☐999
m. New technologies for water heating	→	☐1	☐2	☐999
n. New technologies for computers, IT and office equipment	→	☐1	☐2	☐999
o. Building envelope measures/improvements	→	☐1	☐2	☐999
p. Other (INSERT DESCRIPTION FROM 58, selection 'p')	→	☐1	☐2	☐999

⇒ IF 'YES' FOR ALL THEN SKIP TOQ68; IF 'NO' OR 'DON'T KNOW' FOR AT LEAST 1 ITEM THEN CONTINUE TO Q60 (ONLY INCLUDE THOSE ITEMS THAT WERE ANSWERED 'NO' OR 'DON'T KNOW').

60. What percentage of this equipment at this site has been (or will be) affected by this installation? (INSERT ONLY THOSE ITEMS THAT HAVE BEEN CHECKED 'NO' OR 'DON'T KNOW' FROM Q59) For example, if you had a building that was 10 stories tall and a lighting retrofit was completed on 4 floors, you would say 40% of the lighting equipment was affected. Another example is if your site has 4 buildings with heating systems and 1 of the buildings was upgraded, you would say 25% of the heating equipment was affected.

		Percentage of this equipment affected	Don't know
a. New lighting systems, components, or controls	→	____%	☐999
b. New cooling systems, components or controls	→	____%	☐999
c. New heating systems, components or controls	→	____%	☐999
d. New technologies for process cooling	→	____%	☐999
e. New motors or pumps	→	____%	☐999
f. New motor drive systems	→	____%	☐999
g. New technologies for compressed air	→	____%	☐999
h. New technologies for material conveyors	→	____%	☐999
i. New compressed air systems	→	____%	☐999
j. New technologies for fans	→	____%	☐999
k. New refrigeration systems, components or controls	→	____%	☐999
l. New technologies for energy management control/software	→	____%	☐999
m. New technologies for water heating	→	____%	☐999
n. New technologies for computers, IT and office equipment	→	____%	☐999
o. Building envelope measures/improvements	→	____%	☐999
p. Other (INSERT DESCRIPTION FROM Q58, selection 'p')	→	____%	☐999

61. Did your organization first have the idea to install this measure before participating in BC Hydro's (insert umbrella program as per survey ID)? (INSERT ONLY THOSE ITEMS THAT HAVE BEEN CHECKED 'NO' OR 'DON'T KNOW' FROM Q59)

		Yes, we first had the idea to implement this measure PRIOR to our participation in the conservation program(s)	No, we didn't have the idea to implement this measure until AFTER our participation in the conservation program(s)	Not Applicable	Don't know
a. New lighting systems, components, or controls	→	☐1	☐2	☐998	☐999
b. New cooling systems, components or controls	→	☐1	☐2	☐998	☐999
c. New heating systems, components or controls	→	☐1	☐2	☐998	☐999
d. New technologies for process cooling	→	☐1	☐2	☐998	☐999
e. New motors or pumps	→	☐1	☐2	☐998	☐999
f. New motor drive systems	→	☐1	☐2	☐998	☐999
g. New technologies for compressed air	→	☐1	☐2	☐998	☐999
h. New technologies for material conveyors	→	☐1	☐2	☐998	☐999
i. New compressed air systems	→	☐1	☐2	☐998	☐999
j. New technologies for fans	→	☐1	☐2	☐998	☐999
k. New refrigeration systems, components or controls	→	☐1	☐2	☐998	☐999
l. New technologies for energy management control/software	→	☐1	☐2	☐998	☐999
m. New technologies for water heating	→	☐1	☐2	☐998	☐999
n. New technologies for computers, IT and office equipment	→	☐1	☐2	☐998	☐999
o. Building envelope measures/improvements	→	☐1	☐2	☐998	☐999
p. Other (INSERT DESCRIPTION FROM Q58, selection 'p')	→	☐1	☐2	☐998	☐999

62. If your organization had NOT participated in BC Hydro's (insert umbrella program as per survey ID), would your organization have completed (or made plans to complete) the following project(s)…(INSERT ONLY THOSE ITEMS THAT HAVE BEEN CHECKED 'NO' OR 'DON'T KNOW' FROM Q59)

		…at about the same time as actually done so	…within a year of when actually done so	…more than a year to less than 3 years later	…more than 3 years later	We would have completed this project, but I am unsure about the timing	We would NOT have completed this project	Don't know
a. New lighting systems, components, or controls	→	☐1	☐2	☐3	☐4	☐5	☐6	☐999
b. New cooling systems, components or controls	→	☐1	☐2	☐3	☐4	☐5	☐6	☐999
c. New heating systems, components or controls	→	☐1	☐2	☐3	☐4	☐5	☐6	☐999
d. New technologies for process cooling	→	☐1	☐2	☐3	☐4	☐5	☐6	☐999
e. New motors or pumps	→	☐1	☐2	☐3	☐4	☐5	☐6	☐999
f. New motor drive systems	→	☐1	☐2	☐3	☐4	☐5	☐6	☐999
g. New technologies for compressed air	→	☐1	☐2	☐3	☐4	☐5	☐6	☐999
h. New technologies for material conveyors	→	☐1	☐2	☐3	☐4	☐5	☐6	☐999
i. New compressed air systems	→	☐1	☐2	☐3	☐4	☐5	☐6	☐999
j. New technologies for fans	→	☐1	☐2	☐3	☐4	☐5	☐6	☐999
k. New refrigeration systems, components or controls	→	☐1	☐2	☐3	☐4	☐5	☐6	☐999
l. New technologies for energy management control/software	→	☐1	☐2	☐3	☐4	☐5	☐6	☐999
m. New technologies for water heating	→	☐1	☐2	☐3	☐4	☐5	☐6	☐999
n. New technologies for computers, IT and office equipment	→	☐1	☐2	☐3	☐4	☐5	☐6	☐999
o. Building envelope measures/improvements	→	☐1	☐2	☐3	☐4	☐5	☐6	☐999
p. Other (INSERT DESCRIPTION FROM Q58, selection 'p')	→	☐1	☐2	☐3	☐4	☐5	☐6	☐999

⇒ IF 'WE WOULD NOT HAVE COMPLETED THIS PROJECT" FOR ALL SKIP TO Q65; OTHERWISE CONTINUE TO Q63

63. Which of the following three statements best describes the energy efficiency of the measures that would have been installed at (insert service address, service town) if your organization had NOT participated in BC Hydro's (insert umbrella program as per survey ID). (INSERT ONLY THOSE ITEMS THAT HAVE BEEN CHECKED 1-5 OR 'DON'T KNOW' FROM Q62)

		We would have completed this measure with a LOWER ENERGY EFFICIENCY than actually installed	We would have completed this measure with the SAME ENERGY EFFICIENCY as actually installed	We would have completed this measure with a HIGHER ENERGY EFFICIENCY than actually installed	Not Applicable	Don't know
a. New lighting systems, components, or controls	→	☐1	☐2	☐3	☐998	☐999
b. New cooling systems, components or controls	→	☐1	☐2	☐3	☐998	☐999
c. New heating systems, components or controls	→	☐1	☐2	☐3	☐998	☐999
d. New technologies for process cooling	→	☐1	☐2	☐3	☐998	☐999
e. New motors or pumps	→	☐1	☐2	☐3	☐998	☐999
f. New motor drive systems	→	☐1	☐2	☐3	☐998	☐999
g. New technologies for compressed air	→	☐1	☐2	☐3	☐998	☐999
h. New technologies for material conveyors	→	☐1	☐2	☐3	☐998	☐999
i. New compressed air systems	→	☐1	☐2	☐3	☐998	☐999
j. New technologies for fans	→	☐1	☐2	☐3	☐998	☐999
k. New refrigeration systems, components or controls	→	☐1	☐2	☐3	☐998	☐999
l. New technologies for energy management control/software	→	☐1	☐2	☐3	☐998	☐999
m. New technologies for water heating	→	☐1	☐2	☐3	☐998	☐999
n. New technologies for computers, IT and office equipment	→	☐1	☐2	☐3	☐998	☐999
o. Building envelope measures/improvements	→	☐1	☐2	☐3	☐998	☐999
p. Other (INSERT DESCRIPTION FROM Q58, selection 'p')	→	☐1	☐2	☐3	☐998	☐999

64. Which of the following three statements best describes the AMOUNT or NUMBER of energy-efficient measures that would have been installed at (insert service address, service town) if your organization had NOT participated in BC Hydro's (insert umbrella program as per survey ID)? (INSERT ONLY THOSE ITEMS THAT HAVE BEEN CHECKED 1-5 OR 'DON'T KNOW' FROM Q62)

		We would have installed or completed a LESSER amount	We would have installed or completed the SAME amount	We would have installed or completed a GREATER amount	Not Applicable	Don't know
a. New lighting systems, components, or controls	→	☐1	☐2	☐3	☐998	☐999
b. New cooling systems, components or controls	→	☐1	☐2	☐3	☐998	☐999
c. New heating systems, components or controls	→	☐1	☐2	☐3	☐998	☐999
d. New technologies for process cooling	→	☐1	☐2	☐3	☐998	☐999
e. New motors or pumps	→	☐1	☐2	☐3	☐998	☐999
f. New motor drive systems	→	☐1	☐2	☐3	☐998	☐999
g. New technologies for compressed air	→	☐1	☐2	☐3	☐998	☐999
h. New technologies for material conveyors	→	☐1	☐2	☐3	☐998	☐999
i. New compressed air systems	→	☐1	☐2	☐3	☐998	☐999
j. New technologies for fans	→	☐1	☐2	☐3	☐998	☐999
k. New refrigeration systems, components or controls	→	☐1	☐2	☐3	☐998	☐999
l. New technologies for energy management control/software	→	☐1	☐2	☐3	☐998	☐999
m. New technologies for water heating	→	☐1	☐2	☐3	☐998	☐999
n. New technologies for computers, IT and office equipment	→	☐1	☐2	☐3	☐998	☐999
o. Building envelope measures/improvements	→	☐1	☐2	☐3	☐998	☐999
p. Other (INSERT DESCRIPTION FROM Q58, selection 'p')	→	☐1	☐2	☐3	☐998	☐999

65. Thinking about these additional energy efficiency steps taken (or planned) at this site not covered by BC Hydro assistance, how influential was your participation and learnings from BC Hydro's (insert umbrella program as per survey ID) on your organization's decision to do more on your own? (INSERT ONLY THOSE ITEMS THAT HAVE BEEN CHECKED 'NO' OR 'DON'T KNOW' FROM Q59 → note this brings back the full list of "NO" from Q59)

		Very influential	Somewhat influential	Not too influential	Not at all influential	Don't know
a. New lighting systems, components, or controls	→	☐1	☐2	☐3	☐4	☐999
b. New cooling systems, components or controls	→	☐1	☐2	☐3	☐4	☐999
c. New heating systems, components or controls	→	☐1	☐2	☐3	☐4	☐999
d. New technologies for process cooling	→	☐1	☐2	☐3	☐4	☐999
e. New motors or pumps	→	☐1	☐2	☐3	☐4	☐999
f. New motor drive systems	→	☐1	☐2	☐3	☐4	☐999
g. New technologies for compressed air	→	☐1	☐2	☐3	☐4	☐999
h. New technologies for material conveyors	→	☐1	☐2	☐3	☐4	☐999
i. New compressed air systems	→	☐1	☐2	☐3	☐4	☐999
j. New technologies for fans	→	☐1	☐2	☐3	☐4	☐999
k. New refrigeration systems, components or controls	→	☐1	☐2	☐3	☐4	☐999
l. New technologies for energy management control/software	→	☐1	☐2	☐3	☐4	☐999
m. New technologies for water heating	→	☐1	☐2	☐3	☐4	☐999
n. New technologies for computers, IT and office equipment	→	☐1	☐2	☐3	☐4	☐999
o. Building envelope measures/improvements	→	☐1	☐2	☐3	☐4	☐999
p. Other (INSERT DESCRIPTION FROM Q58, selection 'p')	→	☐1	☐2	☐3	☐4	☐999

66. Thinking about these additional energy efficiency steps taken (or planed) at this site not covered by BC Hydro assistance, would you estimate that these annual electricity savings are greater than or less than the annual electricity savings directly made by participating in the BC Hydro program, or are they about equal?

☐[1]	Annual non-program savings are greater than BC Hydro program savings	⇒ CONTINUE TO Q67
☐[2]	Annual non-program savings are less than BC Hydro program savings	⇒ CONTINUE TO Q67
☐[3]	About equal	⇒ SKIP TO Q68
☐[999]	Don't know	⇒ SKIP TO Q68

67. Approximately how much (IF ANSWER Q66=1 THEN "greater"; IF ANSWER Q66 =2 THEN "less") are these annual non-program savings than the annual BC Hydro program savings? (If ANSWER Q66 =2 also include "e.g., if non-program savings were about a quarter the size of your total program savings, you would write in 25%.")

Please specify: _______% (If ANSWER Q66=1 "**greater than total program savings**"; ANSWER Q66 =2, "**of total program savings**"

☐[999] Don't know

Program Participation: Experience

68. We would like to ask your opinion of several features of BC Hydro's (insert umbrella program as per survey ID). From Excellent to Very Poor, how would you rate the following aspects of the program? (only items A to I and M are randomized, and then the questions about length (J, K and L) be rearranged into the order L, K, J and shown at the bottom of the table

		Excellent	Good	Fair	Poor	Very poor	Don't know/ do not recall	Not applicable
a.	Direct mail information about BC Hydro's (insert umbrella program as per survey ID)	☐1	☐2	☐3	☐4	☐5	☐999	☐998
b.	Information about BC Hydro's (insert umbrella program as per survey ID on the website	☐1	☐2	☐3	☐4	☐5	☐999	☐998
c.	Service provided by BC Hydro personnel	☐1	☐2	☐3	☐4	☐5	☐999	☐998
d.	Service provided by your product supplier(s)/distributor(s)	☐1	☐2	☐3	☐4	☐5	☐999	☐998
e.	Service provided by your contractor(s)/consultant(s) **(for 500,000-528,999 add "**/designer(s)**")**	☐1	☐2	☐3	☐4	☐5	☐999	☐998
f.	Level of incentives offered	☐1	☐2	☐3	☐4	☐5	☐999	☐998
g.	The variety of products funded under the program	☐1	☐2	☐3	☐4	☐5	☐999	☐998
i.	<u>Overall</u> application procedures to receive funding	☐1	☐2	☐3	☐4	☐5	☐999	☐998
m.	Clarity of communications from BC Hydro about your project	☐1	☐2	☐3	☐4	☐5	☐999	☐998
l.	Length of time to receive project approval	☐1	☐2	☐3	☐4	☐5	☐999	☐998
k.	Length of time for the project to be completed	☐1	☐2	☐3	☐4	☐5	☐999	☐998
j.	Length of time to receive the incentive	☐1	☐2	☐3	☐4	☐5	☐999	☐998

68b. Here are some additional aspects of the program. Please rate them from Excellent to Very Poor. [do not randomize]

		Excellent	Good	Fair	Poor	Very poor	Don't know/ do not recall	Not applicable
s.	Knowing how and who to contact at BC Hydro for any project and process questions on the program	☐1	☐2	☐3	☐4	☐5	☐999	☐998
t.	Ease of the online Company Registration for Energy Efficient Lighting Design (EELD) projects	☐1	☐2	☐3	☐4	☐5	☐999	☐998
u.	Consultant/Lighting Designer feedback on the Lighting Calculator's ease of use *(if applicable)*	☐1	☐2	☐3	☐4	☐5	☐999	☐998

68c. On a scale of 1 to 5, with 1 being very little effort and 5 being a lot of effort, please indicate the total effort that was required by your organization to complete your participation in the program?

1 – Very little effort	2	3	4	5 – A lot of effort	Don't know
○	○	○	○	○	○999

69. Overall, how satisfied are you with your experience with BC Hydro's (insert umbrella program as per survey ID)?

- ☐1 Very satisfied
- ☐2 Somewhat satisfied
- ☐3 Neither satisfied or dissatisfied
- ☐4 Somewhat dissatisfied
- ☐5 Very dissatisfied
- ☐999 Don't Know

69b. Thinking about things a little differently, on a scale of 1 to 10, where 1 is not at all satisfied and 10 is extremely satisfied, overall how satisfied are you with BC Hydro's (insert umbrella program as per survey ID)?

1 – Not at all satisfied	2	3	4	5	6	7	8	9	10 – Extremely Satisfied	Don't know
○	○	○	○	○	○	○	○	○	○	○ 999

Follow-Up

70. Based on your experience with BC Hydro's (insert umbrella program as per survey ID), would you recommend the program to organizations similar to your own?

- ☐ 1 Definitely would recommend
- ☐ 2 Probably would recommend
- ☐ 3 Might or might not recommend
- ☐ 4 Probably would <u>not</u> recommend
- ☐ 5 Definitely would <u>not</u> recommend
- ☐ 999 Don't Know

71. Have you recommended BC Hydro's (insert umbrella program as per survey ID) to anyone else?

- ☐ 1 Yes
- ☐ 2 No

72. We would like to know if there are ways to improve BC Hydro's (insert umbrella program as per survey ID). Do you have any suggestions on how the program could be improved? (In consideration of privacy issues, please do not reference any individuals' names.) (OPEN END)

Specify: ____________________

- ☐ 0 No comments

Electricity Management

75. Over the past year, how much of an effort would you say your organization has made to conserve electricity?

- ☐[1] A great deal of effort
- ☐[2] A fair amount of effort
- ☐[3] A little effort
- ☐[4] No effort at all ⇒ ASK Q76, BUT THEN SKIP TO Q78
- ☐[999] Don't know

76. Compared to one year ago, would you say your organization is making more of an effort to conserve electricity, less of an effort, or has there been no change?

- ☐[1] Much more of an effort
- ☐[2] A little more of an effort
- ☐[3] No change
- ☐[4] A little less of an effort
- ☐[5] Much less of an effort
- ☐[999] Don't know

⇒IF Q75=4, THEN SKIP TO Q78, OTHERWISE CONTINUE TO Q77

Energy Management: Motivation

77. In this section, we would like to learn about what motivated your organization to make an effort to manage its use of electricity over the past year.

For each item in the table below, please indicate how much of a factor it has had on your organization's effort to manage its use of electricity over the past year. (RANDOMIZE)

		Major factor	Minor factor	Not a factor	Don't know / Not applicable
a.	Overall level of electricity prices	☐1	☐2	☐3	☐999
b.	The incentive to conserve electricity that is built into BC Hydro's rate structure	☐1	☐2	☐3	☐999
c.	BC Hydro's (INSERT UMBRELLA PROGRAM AS PER SURVEY ID)	☐1	☐2	☐3	☐999
d.	BC Hydro Key Account Manager (Only ask if KAMflag=1)	☐1	☐2	☐3	☐999
e.	Contractors, vendors or customers (e.g., supply chain/marketplace demands)	☐1	☐2	☐3	☐999
f.	Employees	☐1	☐2	☐3	☐999
g.	Energy Manager	☐1	☐2	☐3	☐999
h.	Reducing electricity use to make operating costs as low as possible	☐1	☐2	☐3	☐999
i.	Focus on cost cutting measures due to any economic downturn	☐1	☐2	☐3	☐999
j.	Federal, Provincial, or Local government initiatives	☐1	☐2	☐3	☐999
k.	Increased funds within your company for energy-efficient retrofits	☐1	☐2	☐3	☐999
l.	Reducing electricity use to benefit the environment – it's just the right thing to do	☐1	☐2	☐3	☐999
m.	Other influences: please specify ________________	☐1	☐2	☐3	☐999
n.	Other influences: please specify ________________	☐1	☐2	☐3	☐999

Electricity Management: Barriers

78. In this section, we would like to learn about the barriers your organization may have faced in any effort to manage its use of electricity over the past year. For each item in the table below, please indicate how much of a barrier it has been on your organization's effort to manage its use of electricity over the past year. (RANDOMIZE)

	Major barrier	Minor barrier	No barrier	Don't Know / Not Applicable
a. Lack of funds available for energy-efficient retrofits	☐1	☐2	☐3	☐999
b. Lack of staffing/staffing requirements	☐1	☐2	☐3	☐999
c. Lack of knowledge of where the opportunities for savings might be	☐1	☐2	☐3	☐999
d. Lack of financial incentives for conservation programs and energy efficiency	☐1	☐2	☐3	☐999
e. Can't control employees' behaviour in regards to energy efficiency practice	☐1	☐2	☐3	☐999
f. There are other operational priorities	☐1	☐2	☐3	☐999
g. Takes too much time	☐1	☐2	☐3	☐999
h. Current usage is already near its lowest possible level	☐1	☐2	☐3	☐999
i. Currently leasing the property and no property changes are permitted	☐1	☐2	☐3	☐999
j. All equipment is functioning as efficiently as possible	☐1	☐2	☐3	☐999
m. Interruption to business operations	☐1	☐2	☐3	☐999
k. If applicable: Other barrier (1): specify__________________	☐1	☐2	☐3	☐999
l. If applicable: Other barrier (2): specify__________________	☐1	☐2	☐3	☐999

Comments in Regards to BC Hydro's (insert umbrella program as per survey ID)

79. Do you have any final comments or suggestions in regards to this survey, BC Hydro or its energy conservation programs? (In consideration of privacy issues, please do not reference any individuals' names.) (OPEN-END)

☐[0] No comments

Final Words

80. Are you the original recipient of the survey invitation or was it forwarded along to you by a colleague?

- ☐[1] Original recipient
- ☐[2] The survey was forwarded to me
- ☐[999] Don't know/not sure

81. The key objective of this survey is to collect the necessary information to inform our program evaluation, including how an account's consumption of electricity may vary with the various electrical end-uses associated with it.

To facilitate this, it is important to analyze an account's consumption of electricity for a period dating back to 2010 as a long 'time series' of consumption helps us to better control for year-to-year changes in the weather, the economy, etc.

Rather than asking you to estimate how much electricity this account has consumed over the past couple of years, BC Hydro would like to access this information from your organization's account history and link it to the responses you have given in this survey. We will NOT review any of your organization's bill payment information.

May we please have your organization's permission for BC Hydro to do this?

- ☐[1] Yes
- ☐[2] No

83. If you wish to receive a $50 gift certificate to a home improvement retailer upon completing and submitting the survey, please choose from 1 of 4 retailers and indicate your name, address, city, postal code and phone number below. The information provided below will be stored separately from your survey responses.

Name:

Business Name:

Business Address:

City:

Postal Code:

Business Telephone:

Retailer :

☐1 Canadian Tire

☐2 Home Hardware

☐3 Rona

☐4 Home Depot

☐0 No thanks

Final page after submitting:

Thank you for taking the time to complete this survey. Your responses have been received and secured

POWER SMART PARTNERS –
LOAD DISPLACEMENT INITIATIVES
IMPACT EVALUATION:
F2012-F2018

Final Report

March 31, 2020

Prepared by:

BC Hydro Conservation and Energy Management Evaluation

This page left blank

TABLE OF CONTENTS

This page left blank

Executive Summary

Introduction

This report presents the results of an impact evaluation covering eight load displacement projects implemented during the period from F2012 to F2016. Since the program has ended and no new projects were implemented in F2017 and F2018 and operational data was available for all the projects, the evaluation period covers F2012 to F2018.[1] The projects were funded through the Power Smart Partners-Transmission (PSP-T) Integrated Power Offer (IPO) or Load Displacement (LD) program offers and were not included in the scope of any previous impact evaluations.

Load displacement projects are customer-based generation projects that self-supply part of the customer's site electrical load. For these projects, industrial, commercial and institutional customers received BC Hydro funding and program support to generate their own electricity for self-supply and offset their electricity purchases from BC Hydro. All customer-based generation projects over 50 kW were reviewed through the Integrated Customer Solutions (ICS) process. The load displacement project enabling activities were specifically designed to operate under the ICS framework and remove technical and financial barriers specific to self-generation projects. Load displacement projects were treated as having reduced customer energy purchases similar to energy conservation project initiatives for industrial transmission customers.

Approach

The evaluation objectives and research questions are summarized in the following table.

Table ES.1 Evaluation Objectives and Research Questions

Evaluation Objective	Research Questions
1. Estimate gross electricity generation and peak demand impacts.	What were the evaluated gross electricity generation and demand impacts realized by load displacement projects aggregated by fiscal year and, to the extent possible, disaggregated by relevant factors*?
2. Estimate net electricity generation and peak demand impacts.	What were the relative magnitude of parasitic loads[2] and their energy use as related to the load displacement projects?
	What were the evaluated net electricity generation and demand impacts realized by load displacement projects aggregated by fiscal year and, to the extent possible, disaggregated by relevant factors?
	To what extent did parallel energy procurement initiatives[3] impact the net electricity generation of the load displacement projects?

* Relevant factors may include technology type, primary energy source, seasonal operating mode and operating strategy with other on-site process heat requirements that impact the net electricity generation.

[1] The Load Displacement initiative was no longer available after F2017.

[2] Parasitic load is the electrical energy that is required for the operation of the load displacement project.

[3] Other energy procurement initiatives include electricity purchase agreements, contracted generation baseline loads, and tariff treatments.

The objectives, data sources and methods used for this evaluation are shown in Table ES.2.

Table ES.1. Evaluation Objectives, Data and Method

Evaluation Objectives	Data	Method
1. Estimate gross electricity generation and peak demand impacts.	• Project files • Self-generation eMetering • Customer process requirements • Billing records and Customer Baseline Load (CBL) Statements[4]	• Annual M&V results and evaluation review • Self-generation load shapes, capacity factors and peak-to-energy factors • Engineering calculations
2. Estimate net electricity generation and peak demand impacts.	• Load displacement feasibility studies • Reported savings • Project files	• Engineering estimates of parasitic loads • Annual M&V results and evaluation review

Electricity self-generation impacts were evaluated over the period from F2012 to F2018 based on hourly interval data through annual measurement and verification or annual reconciliation of the site's total generation energy.

Objective 1: Evaluated Gross Electricity Generation and Peak Demand Impacts

Evaluated gross electricity generation is the energy generated due to the program and estimated from the annual M&V results and billing records by fiscal year. Four of the eight projects underwent an annual measurement and verification process for the estimation of gross and net electricity generation. These four projects with M&V are load displacement projects where a new generator was installed. They are grouped in this evaluation under 'New Power Generation' and M&V results were used as the basis of the gross generation energy for evaluation review. The other four load displacement projects were due to refurbishment and upgrading of an existing steam turbine which resulted in incremental generation to already existing generation. These are grouped in this evaluation under 'Rebuilt Turbo Generator'. The annual gross incremental generation energy from the rebuilt units was verified by BC Hydro Contract Management based on revenue metering data for each fiscal year and provided in the customer's billing records. For these projects, the customer's billing records were used as the basis of the gross generation energy for evaluation review.

The gross peak demand impact by the load displacement projects was estimated using the peak-to-energy factor of the total self-generation system at each site. These were evaluated based on hourly interval data during steady-state operations in winter by dividing the average generation power during peak periods by the load displacement project's annual generation energy.

Objective 2: Net Generation Energy and Peak Demand Impacts

The net generation energy is the difference between the energy delivered by the generator and the parasitic energy requirements. The evaluated parasitic energy was estimated based on recent actual performance as the most likely indicator of future performance of the load displacement project.

The parasitic energy estimate for the four New Power Generation projects with M&V was verified by the M&V group using engineering calculations and spot measurements when available. No M&V results were available for the four Rebuilt Turbo Generator projects and a deemed estimate of the incremental parasitic energy was applied based on the default assumption of 3% of incremental gross generation energy[5] of the load displacement project.

[4] CBL Statements are issued annually by BC Hydro for each customer on stepped rate schedule (RS1823B) that includes any adjustment made to a customer's energy bill for the purpose of Customer Baseline Load (CBL) administration.
[5] U.S. Department of Energy (2017). *Uniform Methods Project, Chapter 23: Combined Heat and Power Evaluation Protocol.*

The evaluated net generation peak demand impact of the program was estimated using the same peak-to-energy factors determined for Objective 1, applied to the project-based M&V estimates for parasitic energy and metered load shapes of the generation energy. This assumed that the load shape of the parasitic energy is the same as the load shape of the generation energy.

It was not an objective of this evaluation to attribute changes in generation energy to the load displacement initiatives, which would take into consideration free ridership and spillover. In this evaluation, the term 'net generation impact' refers to the gross generation energy less parasitic energy and does not imply attribution to any intervening initiative. These load displacement projects were assumed to have no free ridership and non-existent spillover, for a net-to-gross ratio of one, for two reasons. First, all self-generation projects had to apply to BC Hydro for generator inter-connection and go through the integrated customer solutions process for review and evaluation. All of the eight load displacement projects in this evaluation were then directed to the load displacement capital incentive offer by BC Hydro and each project had its own business case developed with BC Hydro executive approval of the incentive amount. Hence no free ridership of the capital incentive was anticipated. Second, all generation energy is metered and customers were required to service their self-generation contracts in a prescribed order which was verified by BC Hydro for billing purposes. Hence no spillover of any unreported generation energy was deemed possible.

Results

Objective 1

Table ES.3 shows the number of load displacement projects implemented by fiscal year, as well as the cumulative rated capacity, the evaluated gross generation energy, and the evaluated gross peak demand impact. Results are given as cumulative due to the variation of project results with annual review through measurement and verification.

The peak-to-energy factor was evaluated for each project from hourly interval data based on the average power generated between December and February. Peak-to-energy factors are usually determined using winter weekday evening loads, to correspond with the BC Hydro system peak, but the variations of generated power between winter days of the week (weekday versus weekend) and winter hours of the day (evenings versus other hours of the day) were found to be negligible. The average evaluated peak-to-energy factor was found to be 0.126 MW per GWh, almost 8 percent higher than the industrial transmission rate class average of 0.117 MW per GWh which is typically applied to energy conservation measures. This higher peak-to-energy factor resulted in a higher estimate of peak demand impact for load displacement projects.

A number of other factors were examined to assess the performance of load displacement projects in terms of system availability and capacity utilization. Detailed results discussed in the report indicate that all load displacement projects had excess capacity to potentially increase generation power and energy.

Table ES.3 Evaluated Cumulative Gross Generation Energy and Peak Demand Impact

Fiscal Year	Number of new Projects	Load Displacement Project Type	Cumulative Rated Capacity (MW)	Cumulative Evaluated Gross Generation Energy (GWh/yr)	Cumulative Evaluated Gross Peak Demand Impact (MW)
F2012	2	2x Rebuilt Turbo Generator	26	167	21
F2013	1	1x New Power Generation	28	181	23
F2014	0	-	28	181	23
F2015	2	1x Rebuilt Turbo Generator 1x New Power Generation	31	204	25
F2016	3	1x Rebuilt Turbo Generator 2x New Power Generation	41	263	33
F2017	0	-	41	263	33
F2018	0	-	41	263	33

Objective 2

Table ES.4 summarizes key results by project type and shows the evaluated net generation energy after adjustment for parasitic energy.

Table ES.4. Net Generation Results by Project Type

	Group 1 Rebuilt Turbo Generator	Group 2 New Power Generation
Number of Projects	4	4
Rated Capacity (MW)	32.1	8.9
Evaluated Gross Generation Energy (GWh/yr)	204	59
Evaluated Net Generation Energy (GWh/yr)	198	55
Parasitic Energy Factor	3%	6.5%
Peak-to-Energy Factor (MW/GWh)	0.129	0.117
Realization Rate[6]	91%	98%
Load displacement to facility energy ratio[7]	18%	14%
LD energy to total self-generation energy ratio[8]	25%	100%

[6] Realization rate is the ratio of evaluated net energy generation to the expected generation energy, which is the contracted generation energy of the incentive agreement.

[7] The load displacement to facility energy ratio indicates the proportion of site energy consumption that was displaced by the load displacement project on an annual basis.

[8] The load displacement to total self-generation ratio indicates the proportion of total self-generation energy at the site that was contributed by the load displacement project on an annual basis.

Table ES.5 shows a summary of reported and evaluated net generation energy and peak demand by fiscal year. Year over year reporting of load displacement generation energy improved as the operation of the systems reached steady-state. However, there was a time lag because measurement and verification results or billing reconciliation for a given reporting year only became available after fiscal year-end and were then used as the best available estimate for the next year. Considering this time lag in reporting of variations in performance between fiscal years, the evaluated net generation energy was estimated on average to have achieved 96 percent of the reported generation energy. The variance is primarily due to inconsistency in reporting of Rebuilt Turbo Generator projects, using their expected generation energy instead of the actual generation energy, and the lack of accounting of parasitic energy in reported savings for these projects. If the reported generation energy were adjusted for actual generation energy and estimated parasitic energy, the overall variance between reported and evaluated net generation energy of all eight load displacement projects would be reduced to less than one percent.

Table ES.5. Summary of Net Generation Energy and Peak Demand Impact

Fiscal Year	Net Generation Energy (GWh/yr)		Net Peak Demand Impact (MW)	
	Reported	Evaluated	Reported	Evaluated
F2012	254	162	30	20
F2013	254	176	30	22
F2014	195	176	23	22
F2015	215	196	25	25
F2016	271	253	32	32
F2017	260	253	30	32
F2018	262	253	31	32

Findings and Recommendations

Findings

1. Eight load displacement projects were evaluated for a total of 263 GWh per year in gross generation energy and 253 GWh per year in net generation energy. This resulted in 33 MW of gross peak demand impact and 32 MW of net peak demand impact.
2. Seven of the eight load displacement projects ranged from 1 MW to 5 MW in size and one exceeded 25 MW in rated capacity. Seven of the load displacement projects were considered combined heat and power and used biomass and bioenergy as the primary energy source.
3. The four Rebuilt Turbo Generator projects were found to have average availability, capacity and utilization factors of 94 percent, 78 percent and 72 percent respectively. The other four projects were of the New Power Generation type and were found to have average availability, capacity and utilization factors of 91 percent, 84 percent and 76 percent respectively.
4. The load displacement project realization ranged from 75 percent to 107 percent, with a weighted average project realization rate of 91 percent for Rebuilt Turbo Generator and 98 percent for New Power Generation type projects. The overall program realization rate was 92 percent.
5. All projects undergo annual verification of the generation energy using hourly interval data. Rebuilt Turbo Generator load displacement projects had verification of actual gross generation energy recorded by BC Hydro Contract Management, whereas New Power Generation projects underwent

annual measurement and verification activities, recording both gross and net generation energy. The reported generation energy is adjusted yearly based on this annual review for all New Power Generation type projects but not for Rebuilt Turbo Generator type projects.

6. The generation energy provided in the customer's annual CBL Statements was found to be the best available estimate for projects without annual measurement and verification. These generation energy records explain most of the variance between reported and evaluated gross generation energy for Rebuilt Turbo Generator type load displacement projects.
7. The peak-to-energy factor was found to be 8 percent higher than the industrial rate class average because six of the eight projects generated more power during BC Hydro's system winter peak as a result of higher availability factors in winter months. Generator shutdowns and annual maintenance periods, which decreased overall availability, were observed to typically occur in the spring and summer months. Two projects had peak-to-energy factor lower than the industrial rate class average because of higher process heat requirements in winter.
8. Parasitic energy is the difference between gross and net generation energy and was evaluated at 3 percent for Rebuilt Turbo Generator projects and 6.5 percent for New Power Generation projects. New Power Generation projects have more auxiliary energy requirements than incremental generation projects from Rebuilt Turbo Generators. The parasitic energy explains most of the difference between reported and evaluated net generation energy.
9. The average weighted persistence of load displacement projects was estimated to be 16 years and ranging from 10 years to 20 years. The BC Hydro Persistence Standard indicates 20 years persistence for New Power Generation type projects and 15 years persistence for Rebuilt Turbo Generator projects. Any changes to generation energy and persistence are captured in the annual M&V and engineering review process.
10. The evaluation found evidence of continuous improvement of the utilization factor of three New Power Generation load displacement projects through the annual review and the M&V process. Project underperformance was observed due to restriction in condensing capacity, fuel supply, and electrical metering issues that were identified and corrected during the first three years of operating the load displacement projects.

Recommendations

The following recommendations are for the BC Hydro Load Displacement initiative managers based on the findings of this evaluation.

1. Continue to conduct annual review and measurement and verification of all load displacement projects for reporting of actual net generation energy per fiscal year.
2. The program should use the generation energy from customer's annual CBL Statements as the best available estimate when annual measurement and verification results are not available. These apply to Rebuilt Turbo Generator type projects at large industrial customer sites with transmission service that are on the stepped rate (RS1823B).
3. The program should apply a 3% reduction to the gross generation energy for projects without an engineering estimate of parasitic energy, i.e., load displacement projects of Rebuilt Turbo Generator type.

Conclusions

BC Hydro's load displacement initiatives achieved 92 percent of expected generation energy during fiscal years F2012 to F2018. The New Power Generation projects achieved 98 percent due to continuous improvement of project performance, whereas the Rebuilt Turbo Generator projects achieved 91 percent due to overestimated utilization factor and underestimated parasitic energy. The evaluated net generation energy of both types of load displacement projects was found to produce an equivalent reduction in site energy purchases.

1.0 Introduction

1.1 Evaluation Scope

This report presents the results of an impact evaluation covering eight (8) load displacement projects implemented during the period from F2012 to F2016. Since the program has ended and no new projects were implemented in F2017 and F2018 and operational data was available for all the projects, the evaluation period covers F2012 to F2018. The projects were funded through the Power Smart Partners-Transmission Integrated Power Offer (IPO) or Load Displacement (LD) program offers. These load displacement projects were not included in the scope of any impact evaluations of the BC Hydro Power Smart Partners – Transmission (PSP-T) and Leaders in Energy Management – Transmission (LEM-T) programs.

1.2 Organization of the Report

The report is organized as follows. Section 1 covers the evaluation scope, the organization of the report and the initiative description. Section 2 discusses the approach to the evaluation, including evaluation objectives, methodology review, data sources, and methods. Section 3 provides the results organized by evaluation objective. Section 4 provides findings and recommendations. Section 5 provides conclusions. Additional supporting material is included in the appendices.

1.3 Initiative Description

Load displacement projects are customer-based generation projects that self-supply part of the customer's site electrical load. For these projects, industrial, commercial and institutional customers received BC Hydro funding and program support to generate their own electricity for self-supply and offset their electricity purchases from BC Hydro. All customer-based generation projects over 50 kW were reviewed through the Integrated Customer Solutions (ICS) process. The load displacement project enabling activities were specifically designed to operate under the ICS framework and remove technical and financial barriers specific to self-generation projects. Incentives for load displacement activities were modelled as having reduced customer energy purchases similar to energy conservation project initiatives for industrial transmission customers.

Parallel energy procurement initiatives for customer-based self-generation may include Contracted Generator Baseline (GBL) with an Energy Purchase Agreement (EPA), and the non-contracted GBL to offset energy purchases under the TSR rate structure.

BC Hydro's program records, generator interval data, as well as billing data of the customer's total self-generation energy by BC Hydro Contract Management were annually verified to ensure that there is only single attribution of any customer self-generation energy and no double counting among parallel self-generation initiatives.

Parallel demand side management (DSM) initiatives include previous and current BC Hydro DSM programs, such as LEM-T (formerly known as PSP-T) and LEM-D (formerly known as PSP-D), that allow incremental self-generation projects in their respective program portfolio. These types of self-generation projects were typically incremental generation of less than 1 MW in size and were included in the impact evaluation of their respective DSM program. None of the eight load displacement projects in this evaluation occurred in parallel with incremental self-generation projects through other DSM programs.

2.0 Approach

2.1 Evaluation Objectives

The evaluation objectives and research questions are summarized in the following table.

Table 2.1. Evaluation Objectives and Research Questions

Evaluation Objective	Research Questions
1. Estimate gross electricity generation and peak demand impacts.	What were the evaluated gross electricity generation and demand impacts realized by load displacement projects aggregated by fiscal year and, to the extent possible, disaggregated by relevant factors*?
2. Estimate net electricity generation and peak demand impacts.	What were the relative magnitude of parasitic loads and their energy use as related to the load displacement projects? What were the evaluated net electricity generation and demand impacts realized by load displacement projects aggregated by fiscal year and, to the extent possible, disaggregated by relevant factors[1]? To what extent did parallel energy procurement initiatives impact the net electricity generation of the load displacement projects?

* Relevant factors may include technology type, primary energy source, seasonal operating mode and operating strategy with other on-site process heat requirements that impact the net electricity generation.

In this evaluation and in accordance with industry standard practice for evaluating combined heat and power projects[9], gross electricity generation is defined as the total electricity produced by the generator. Net electricity generation is defined as the gross electricity generated minus parasitic energy, which represents the net impact of the load displacement project to the customer. Parasitic energy is the electrical energy required to operate the load displacement project. The parasitic energy requirements are necessary auxiliary loads such as external generator excitation power, material handling, heating and cooling, lubrication equipment, and other electrical needs required to operate the load displacement project..

2.2 Methodology Review

The main focus of most evaluations is to determine the energy savings impacts of the installed measure. The evaluation of load displacement projects is basically similar to estimating the net electricity impacts from the self-generation system at the customer side of the meter. The Uniform Methods Project (UMP) has developed the basic scope, terminology and methodology for evaluation of combined heat and power systems that are used to meet on-site energy needs. It focuses on systems that are generally sized at less than five megawatts (MW) in rated electrical generating capacity and ensures consistency with other UMP protocols.

While a number of utilities provide incentives for load displacement projects under their custom commercial and industrial program offerings, there are only a few program administrators in North America that offer programs specifically focused on load displacement. These include California's Self Generation Incentive Program, New York State Energy Research and Development Authority's Distributed Generation Combined Heat and Power program, and Manitoba Hydro's Bioenergy Optimization Program.

In most evaluations, results were reported overall but also by technology type and primary energy source. The impact evaluations relied on metering a sample of projects and applying those results to non-metered systems

[9] U.S. Department of Energy (2017). *Uniform Methods Project, Chapter 23: Combined Heat and Power Evaluation Protocol.*

for estimation of gross or net generation. Both California and New York used tele-metering (or web-based metering) to perform systematic and continuous hourly monitoring of system outputs for certain distributed generation systems. These data sources were supplemented by short-term on-site metering and billing reviews, where necessary. The short-term on-site metering typically followed the International Performance Measurement and Verification Protocol (IPMVP®) Option B procedure (retrofit-isolation, all parameter measurement).[10]

2.3 Methodology

In this evaluation, electricity self-generation impacts were evaluated over the period from F2012 to F2018 based on hourly interval data and annual measurement and verification reports when available. The objectives, data sources and methods used for this evaluation are summarized in the table below, and described in more detail following the table.

Table 2.2. Evaluation Objectives, Data and Method

Evaluation Objectives	Data	Method
1. Estimate gross electricity generation and peak demand impacts.	• Project files • Self-generation eMetering • Customer process requirements • Billing records and Customer Baseline Load (CBL) Statements	• Annual M&V results and evaluation review • Self-generation load shapes, capacity factors and peak-to-energy factors • Engineering calculations
2. Estimate net electricity generation and peak demand impacts.	• Load displacement feasibility studies • Reported savings • Project files	• Engineering estimates of parasitic loads • Annual M&V results and evaluation review

Objective 1: Evaluated Gross Electricity Generation and Peak Demand Impacts

Evaluated gross electricity generation is the energy generated due to the program and estimated from the annual M&V results and billing records by fiscal year. Four of the eight projects underwent an annual measurement and verification process for the estimation of gross and net electricity generation. These four projects with M&V are load displacement projects where a new generator was installed, and they are grouped in this evaluation under 'New Power Generation'. The other four load displacement projects at transmission customer sites were due to refurbishment and upgrading of an existing steam turbine with capacity or efficiency improvements which resulted in incremental generation to already existing generation. These are grouped in this evaluation under 'Rebuilt Turbo Generator'. The annual gross incremental generation energy from the rebuilt units was verified by BC Hydro Contract Management for each fiscal year and provided in the customer's billing records, such as the Customer Baseline Load (CBL) Statement, for each fiscal year. Measurement and verification of load displacement projects for Rebuilt Turbo Generators could not be conducted due to interactive effects and rate specific billing formula applied for attribution of the customer's total self-generation energy across parallel initiatives under the terms and conditions of the self-generation agreements. Therefore, the customer's annual CBL Statements were used in the absence of M&V results as the basis of the gross generation energy for evaluation review.

[10] Efficiency Valuation Organization (October, 2016). *Core Concepts. International Performance Measurement and Verification Protocol.*

Baselines were determined on a project by project basis. Load displacement projects can occur at customer locations where self-generation is being implemented with new generators or where incremental generating capacity was added to an existing generating system. In all cases the generation energy was determined annually based on post-implementation measurements only.

Incremental generation from Rebuilt Turbo Generator projects involving optimization of existing self-generation, i.e., turbine upgrades, may have required additional billing adjustments during annual reconciliation because customers with a contracted GBL must service their generation contracts in a prescribed order.

Additional generation energy adjustments can be required during Authorized Plant Outages (APO) or when there were significant changes to the properties and composition of fuel supply and process load requirements. Bioenergy sources can experience much greater deviation from design conditions, which can substantially impact the energy generated through the load displacement program. In these cases, the project's long-term generation energy impact was reviewed and any shortfalls in generation energy were settled financially on an annual basis.

The following table shows the characteristics of the various projects, disaggregated by relevant factors including project type, technology type, primary energy source, seasonal operating mode, and operating strategy with other on-site process heat requirements that impact the net electricity generation.

Table 2.3. Distribution of Projects by Relevant Factors

Type of LD Project	Rebuilt Turbo Generator	New Power Generation	New Power Generation	New Power Generation
Number of Projects	4	2	1	1
Customer Rate Class	Transmission	Transmission	Transmission	Transmission
Industry Sector	Pulp Mills	Wood Products	District Energy	Municipal Water
Primary Energy Source	biomass	biomass	renewable natural gas[11]	clean water flow
Technology Type	steam turbine generator	organic rankine cycle	internal combustion engine	pelton wheel
Combined Heat and Power (CHP)	with heat for process steam	with heat for product drying	with heat for space and water	No CHP
Generation Energy (Data Source)	gross (CBL Statements)	gross and net (M&V Reports)	gross and net (M&V Reports)	gross and net (M&V Reports)
Parasitic Energy	Deemed estimate	Engineering estimate	Engineering estimate	Engineering estimate
Seasonality	Fairly constant power generation	Less power generation in winter	Fairly constant power generation	Highly seasonal power generation

The first step was to collect the project data from the program tracking system and the TSR administrative records for each project and each fiscal year. This included data from the initial engineering review, which provided the expected generation energy based on the incentive agreement of the load displacement projects.

[11] Renewable natural gas is derived from biogas, which is produced from decomposing organic waste from landfills, agricultural waste and wastewater from treatment facilities. In this application it is produced in a different location than the load displacement project.

Records of post implementation review and M&V reported values of energy generated by fiscal year were also collected. For Rebuilt Turbo Generator projects with incremental self-generation, the project related annual generation energy on the customer's CBL Statements was identified as the best available estimate of the project's gross energy generated in each fiscal year. The load displacement energy provided on the CBL Statements was verified by BC Hydro Contract Management under the terms and conditions of all contractual agreements. The Evaluation team did not have access to the contracts nor the details on the attribution of the total actual generation energy.

Due to the variability of historic generation output and verified annual reporting requirements of all load displacement projects, the evaluation estimated the average generation energy and relevant factors for the project's remaining period of persistence (labelled as evaluation review) to provide an estimate of the expected performance of these projects.

The gross peak demand impact by the load displacement projects was estimated using the peak-to-energy factor of the total self-generation system at each site. These were evaluated based on hourly interval data during steady-state operations in winter. The peak-to-energy factor is calculated by dividing the average generation power during BC Hydro's system peak demand (winter weekday evenings) by the load displacement project's annual generation energy, as in the following equation:

Equation 1

$$Peak\text{-}to\text{-}Energy\ Factor\ (\frac{MW}{GWh}) = \frac{Average\ Winter\ Evening\ Gross\ Generation\ Power\ (MW)}{Annual\ Gross\ Generation\ Energy\ (GWh\ per\ year)}$$

Three additional factors were also calculated from hourly interval data to characterise and compare the system performance of each load displacement project: the capacity factor, the availability factor, and the utilization factor. These are described in more details below.

The capacity factor for a New Power Generation system is the actual average running power output of the system divided by the rated installed capacity of the system, as shown in Equation 2. For consistency and comparison, the capacity factor of the Rebuilt Turbo Generator projects with incremental generation capacity, was estimated to be equal to the capacity factor of the total generating system. Because some projects experienced performance issues during initial commissioning, the evaluated capacity factor was estimated based on recent actual performance as the most likely indicator of future performance of the load displacement project.

Equation 2

$$Capacity\ Factor\ (CF) = \frac{Actual\ average\ gross\ power\ generated}{Rated\ installed\ capacity\ of\ generation\ system}$$

The availability factor is the percentage of time the system was actually operating for each fiscal year as given by the equation below. Again, the evaluated availability factor was estimated based on recent actual performance as the most likely indicator of future performance of the load displacement project.

Equation 3

$$Availability\ Factor\ (AF) = \frac{Actual\ hours\ the\ system\ is\ running\ in\ a\ year}{8760\ hours\ per\ year}$$

The utilization factor is the extent to which the load displacement system is actually used. This performance driver depends on the percentage of time the system was operating as well as on the degree to which the system operated at rated capacity when running and was calculated as the product of the capacity factor and the availability of the system as given by equation 4. Similarly, the evaluated utilization factor was estimated to represent the project's most likely indicator of future performance.

Equation 4

$$Utilization\ Factor\ (UF) = CF\ x\ AF = \frac{Actual\ annual\ gross\ energy\ generated\ (kWh/yr)}{Rated\ system\ capacity\ (kW)\ x\ 8760\ (hours/year)}$$

The four factors were estimated individually for each of the projects, and the results were also aggregated to compare the two types of load displacement projects.

Objective 2: Net Generation Energy and Peak Demand Impacts

The net generation energy is the difference between the energy delivered by the generator and the parasitic energy requirements, as calculated using the following equation. The evaluated parasitic energy was estimated based on recent actual performance as the most likely indicator of future performance of the load displacement project.

Equation 5

$$Net\ Generation\ Energy = Gross\ Generation\ Energy - Parasitic\ Energy$$

The parasitic energy estimate for the four New Power Generation projects with M&V was verified by the M&V group using engineering calculations and spot measurements when available. No M&V results were available for the four Rebuilt Turbo Generator projects and a deemed estimate of the incremental parasitic energy was applied based on the default assumption of 3% of incremental gross generation energy[12] of the load displacement project using equation 6.

Equation 6

$$Parasitic\ energy\ of\ incremental\ generation = Gross\ Generation\ Energy\ \times 3\%$$

The evaluated net generation peak demand impacts of the program were estimated using the same peak-to-energy factors determined for Objective 1, applied to the project-based M&V estimates for parasitic energy and metered load shapes of the generation energy. This assumed that the load shape of the parasitic energy is the same as the load shape of the generation energy.

Since the expected generation energy or initial engineering estimates were based on net generation energy, each project's realization is calculated as the ratio of net generation energy to the expected generation energy. The projects were aggregated by type and the realization rate was calculated for the two types of projects. As before, the evaluated project realization was estimated as the most likely indicator of future performance of the load displacement project.

Equation 7

$$Project\ Realization\ Rate = \frac{Evaluated\ Net\ Generation\ Energy}{Expected\ Generation\ Energy}$$

[12] U.S. Department of Energy (2017). *Uniform Methods Project, Chapter 23: Combined Heat and Power Evaluation Protocol.*

Another relevant factor estimated primarily for project comparison and program overview was the ratio of the load displacement generation energy compared to the facility's energy use. The facility energy use was estimated from the annual energy purchases from BC Hydro plus the total self-generation energy at the site.

Equation 8

$$Load\ Displacement\ to\ Facility\ Energy\ Ratio = \frac{Evaluated\ Net\ Generation\ Energy\ (kWh/yr)}{Facility\ Energy\ Use\ (kWh/yr)}$$

$$= \frac{Evaluated\ Net\ Generation\ Energy\ (kWh/yr)}{Energy\ Purchases\ (kWh/yr) + Site\ Generation\ Energy (kWh/yr)}$$

Also the ratio of the project's load displacement generation energy to the total self-generation energy at the site was determined using the following equation:

Equation 9

$$Load\ Displacement\ to\ Total\ Self\text{-}generation\ Energy\ Ratio = \frac{Evaluated\ Gross\ Generation\ Energy}{Total\ Self\text{-}generation\ Energy}$$

It was not an objective of this evaluation to attribute changes in generation energy to the load displacement initiatives, which would take into consideration free ridership and spillover. In this evaluation, the term 'net generation impact' refers to the gross generation energy less parasitic energy and does not imply attribution to any intervening initiative.

These load displacement projects are assumed to have had no free ridership and non-existent spillover, for a net-to-gross ratio of one, for two reasons: First, all self-generation projects had to apply to BC Hydro for generator inter-connection and go through the integrated customer solutions process for review and evaluation. All of the eight load displacement projects in this evaluation were then directed to the load displacement capital incentive offer by BC Hydro and each project had its own business case developed with BC Hydro executive approval of the incentive amount. Hence no free ridership of the capital incentive was anticipated. Second, all generation energy is metered and customers were required to service their self-generation contracts in a prescribed order which was verified by BC Hydro for billing purposes. Hence no spillover of any unreported generation energy was deemed possible.

2.4 Alternative Methodologies

The evaluation scope was limited to estimating the gross and net electricity generation energy and peak demand impact, and because the electricity impact of all projects was assessed based on metered interval data that was verified and reconciled with billing data and tariff treatment. Therefore, no alternative methodology was considered for this evaluation.

Alternative evaluation approaches and methodologies are available and differ in levels of rigor applied in estimating the full impacts of CHP projects. Besides net electricity impacts, other associated CHP performance parameters considered for evaluation may include:

1. Net fuel impact
2. Net electrical efficiency
3. Useful heat recovery rate
4. Overall fuel conversion efficiency
5. Electrical energy offset
6. Fuel offset

Although less frequently considered in CHP evaluations are other issues like degradation in availability and performance due to aging during the project's lifetime, normalization of performance to weather, process loads for CHP systems that serve process loads, relationship between the cost of fuel and electricity, heating and cooling loads served, and overall grid effects. Free ridership and spillover do not typically occur in CHP projects greater than 1 MW, because CHP projects are complex and require detailed engineering estimates and effort in obtaining permits, commissioning, and supporting maintenance and operation. These related performance factors were not used in this evaluation because only eight projects were completed in the evaluation period and the fact that the load displacement initiative was no longer available to customers since F2017.

3.0 Results

3.1 Gross Generation Energy and Peak Demand Impacts

Gross generation energy is the energy generated by customers as a result of participation in the load displacement initiative. As detailed in Section 2.3, gross generation energy was determined from M&V results for the four New Power Generation projects, and from CBL Statements and tariff treatment for the four Rebuilt Turbo Generator projects.

Evaluated results below are given as the best available estimate of overall project performance, considering the annual review and verification of the actual reported energy generated for each load displacement project.

Table 3.1. Gross Generation Results by Project Type

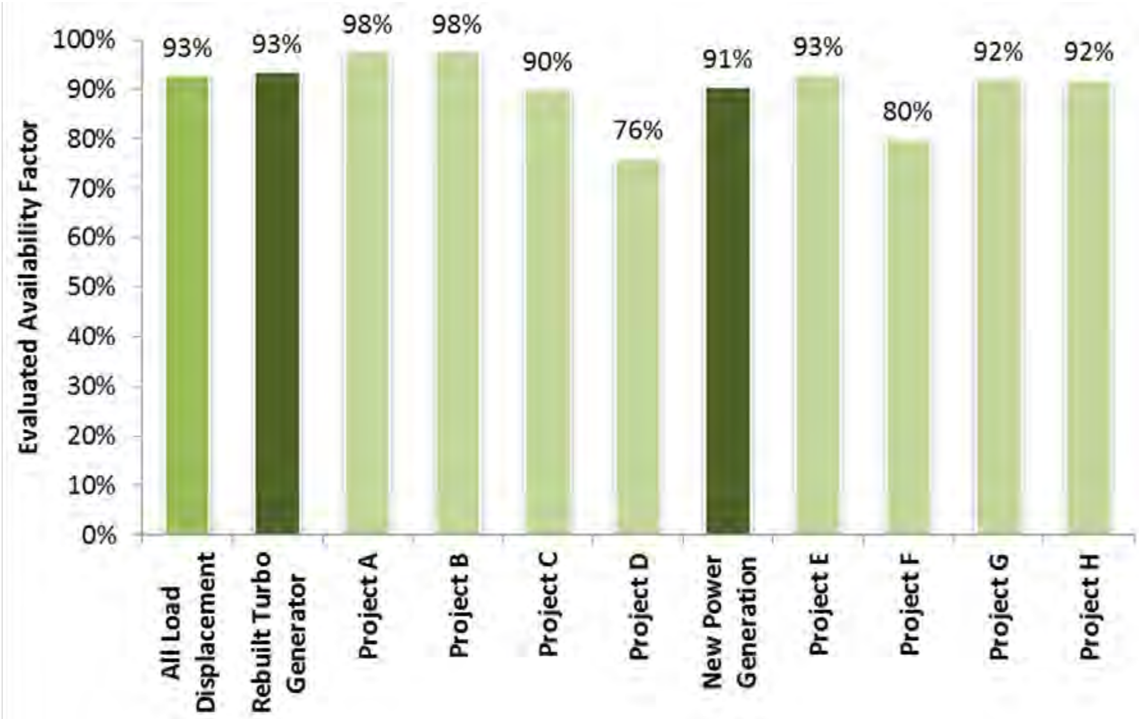
	Group 1 Rebuilt Turbo Generator	Group 2 New Power Generation
Number of Projects	4	4
Rated Capacity (MW)	32.1	8.9
Expected Generation Energy (GWh/yr)	218	56
Evaluated Gross Generation Energy (GWh/yr)	204	59
Availability Factor	93%	91%
Capacity Factor	77%	84%
Utilization Factor	72%	76%
Peak-to-Energy Factor (MW/GWh)	0.129	0.117

The following section describes the evaluated results of the relevant factors by project and project type. Additional details of relevant factors by project type and fiscal year are provided in Appendices C and D.

Availability Factor

The availability factor represents the percentage of time a project is operating within a given fiscal year and generating electricity, and was calculated from hourly interval data. Figure 3.1 shows the evaluated availability factor by project and in aggregate by project type.

Figure 3.1. Availability Factor by Project and Project Type



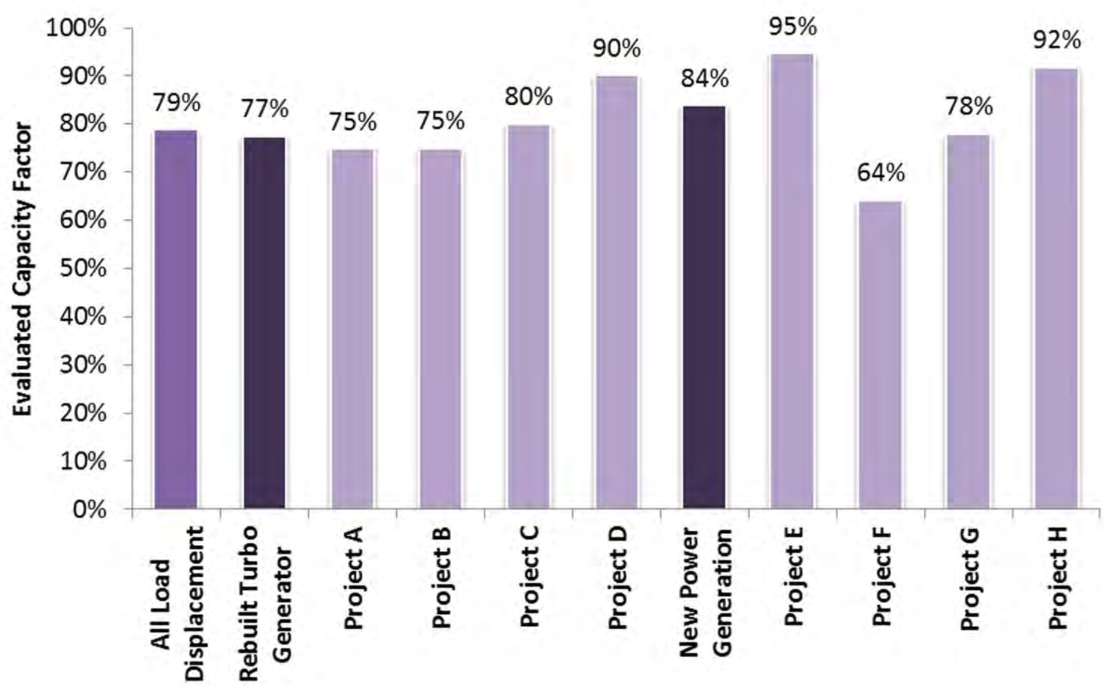
In general, the availability factor by individual projects ranged from 76 percent to 98 percent and Rebuilt Turbo Generator projects had a weighted average of 93 percent, slightly higher than New Power Generation projects which had a weighted average availability factor of 91 percent. These availability factors are as expected of these types of load displacement projects[13], especially with biomass as the primary energy source.

Capacity Factor

The capacity factor relates the average loading of the generator to its rated capacity and was calculated from hourly interval data. The capacity factor of Rebuilt Turbo Generator projects was estimated based on the average generated power and the rated capacity of the total generation system. The results are shown in Figure 3.2 for individual projects and in aggregate by project type. The capacity factor ranged from 64 percent to 95 percent, indicating that all load displacement projects had excess capacity to potentially increase generation power and energy.

[13] Catalog of CHP Technologies, U.S. Environmental Protection Agency Combined Heat and Power Partnership, September 2017.

Figure 3.2. Capacity Factor by Project and Project Type

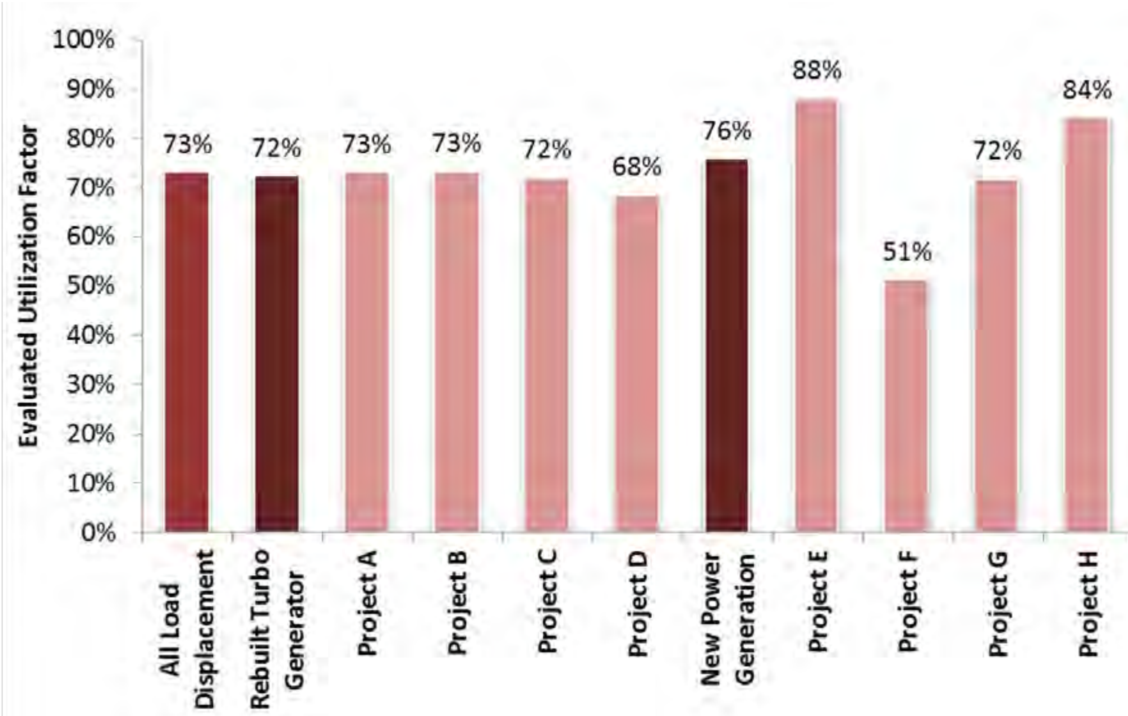


The capacity factor was found to increase over time (see Appendix D) for New Power Generation projects, reaching a weighted average of 84 percent. Likewise for the Rebuilt Turbo Generator projects, the capacity factor was found to average around 77 percent for all years of past operation. The reasons for lower capacity factors were not evaluated but can be due to variations in process heat requirements at mills and to variability in the fuel supply and quality that is common with biomass-based generation.

Utilization Factor

The utilization factor is the overall utilization of the load displacement project and is calculated as the product of the availability factor and the capacity factor. It is shown in Figure 3.3 and individual projects were found to range from 51 percent to 88 percent. On average, New Power Generation projects achieved a utilization factor of 76 percent and Rebuilt Turbo Generator projects 72 percent, for a weighted average utilization factor of 73 percent for all load displacement projects.

Figure 3.3. Utilization Factor by Project and Project Type

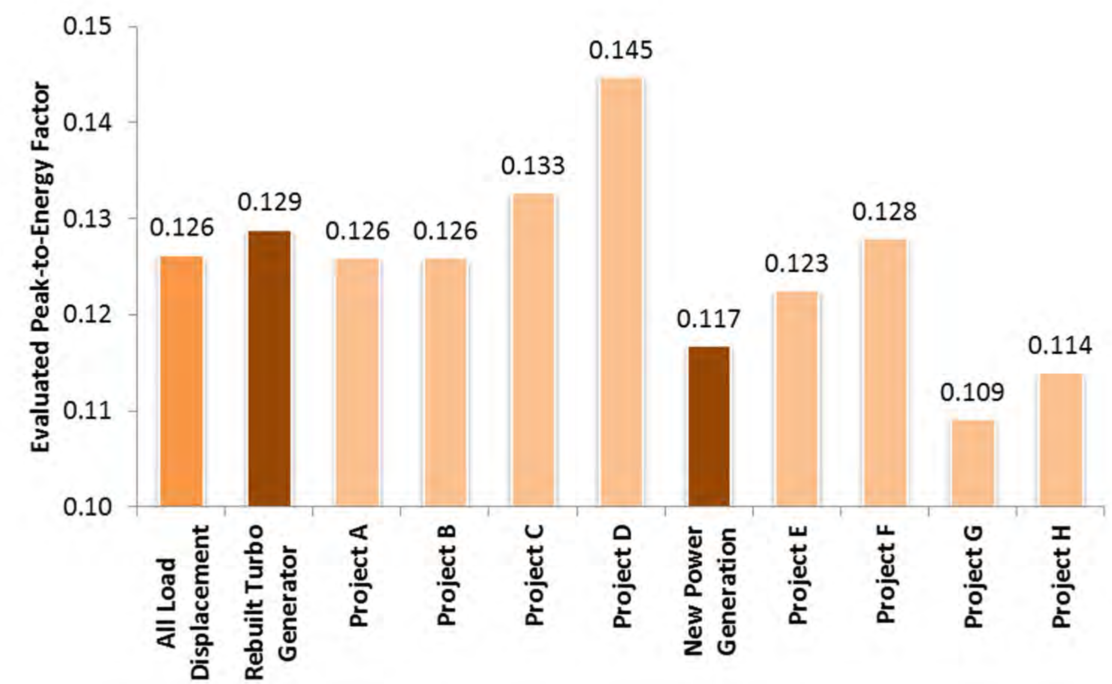


Peak-to-Energy Factor

The peak-to-energy factor was evaluated for each project from hourly interval data based on the average power generated between December and February and is shown in Figure 3.4. Peak-to-energy factors are usually determined using winter weekday evening loads, to correspond with the BC Hydro system peak, but the variations of generated power between winter days of the week (weekday versus weekend) and winter hours of the day (evenings versus other hours of the day) were negligible.

The evaluated peak-to-energy factor was found to be 0.126 MW per GWh, almost 8 percent higher than the industrial transmission rate class average of 0.117 MW per GWh which is typically applied to energy conservation measures. This higher peak-to-energy factor results in a higher estimate of peak demand impact from load displacement projects.

Figure 3.4 Peak-to-Energy Factor by Project and Project Type



Six of the eight projects had an evaluated peak-to-energy factor higher than the industrial rate class average of 0.117 MW per GWh used in the reported savings. Overall, this result indicates that the average power generated in winter is greater than the average power generated during the year. On the other hand, the two projects with lower evaluated peak-to-energy factor had a seasonal winter impact with lower generating power in winter, likely due to higher winter process heat requirements at the facility.

The average peak-to-energy factor for New Power Generation projects was found to be 0.117 MW per GWh, which is close to a flat load. In contrast, the Rebuilt Turbo Generator projects had, on average, a higher peak-to-energy factor of 0.129 MW per GWh.

The number of load displacement projects implemented by fiscal year, as well as the cumulative rated capacity, the evaluated gross generation energy, and the evaluated gross peak demand impact are summarized in the table below. Results are given as cumulative due to the variation of project results with annual review through measurement and verification.

Table 3.2 Evaluated Gross Generation Energy and Peak Demand Impact

Fiscal Year	Number of New Projects	Load Displacement Project Type	Cumulative Rated Capacity (MW)	Cumulative Evaluated Gross Generation Energy (GWh/yr)	Cumulative Evaluated Gross Peak Demand Impact (MW)
F2012	2	2x Rebuilt Turbo Generator	26	167	21
F2013	1	1x New Power Generation	28	181	23
F2014	0	-	28	181	23
F2015	2	1x Rebuilt Turbo Generator 1x New Power Generation	31	204	25
F2016	3	1x Rebuilt Turbo Generator 2x New Power Generation	41	263	33
F2017	0	-	41	263	33
F2018	0	-	41	263	33

The evaluated gross generation energy of the eight load displacement projects, with 41 MW of cumulative generating capacity, 93% availability factor, and 79% capacity factor, displaced gross energy purchases of 263 GWh per year and reduced BC Hydro's system peak demand by 33 MW.

3.2 Net Generation Energy and Peak Demand Impacts

The evaluated net generation energy is the net energy impact from the load displacement program and includes the adjustment for parasitic energy. Since these projects have annual reporting requirements, the generation energy and relevant factors given in the table below are aggregated by project type.

Table 3.3 Net Generation Results by Project Type

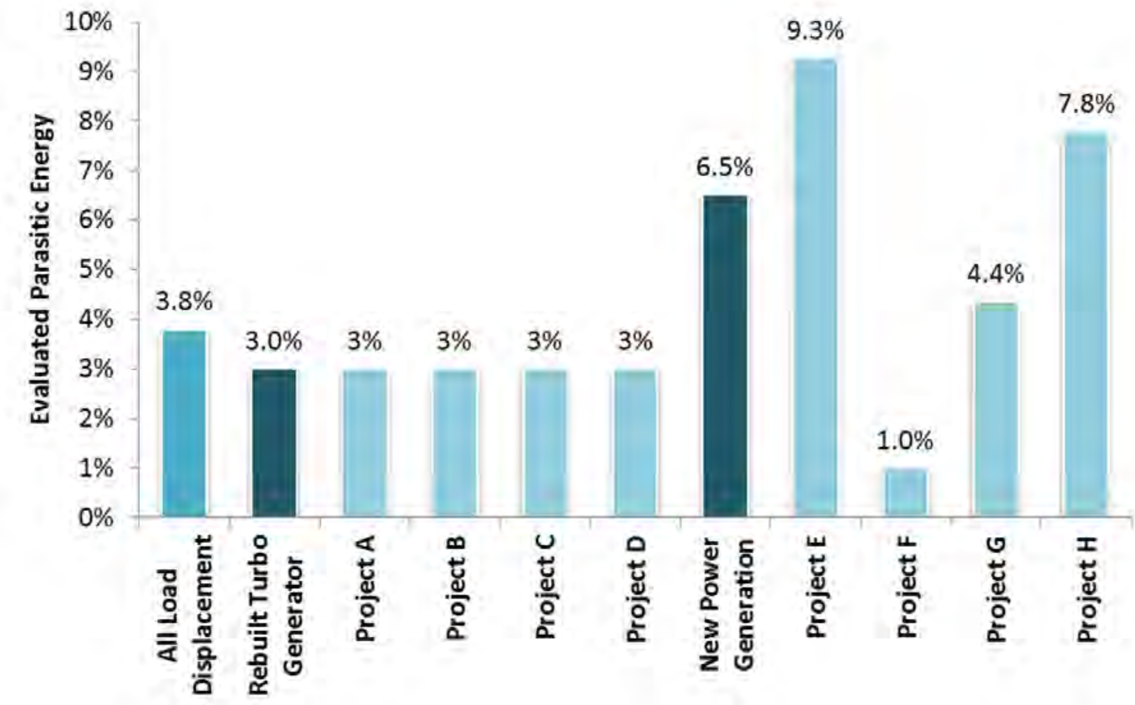
	Group 1 Rebuilt Turbo Generator	Group 2 New Power Generation
Number of Projects	4	4
Rated Capacity (MW)	32.1	8.9
Evaluated Gross Generation Energy (GWh/yr)	204	59
Evaluated Net Generation Energy (GWh/yr)	198	55
Parasitic Energy Factor	3%	6.5%
Peak-to-Energy Factor (MW/GWh)	0.129	0.117
Realization Rate	91%	98%
Load displacement to facility energy ratio*	18%	14%
LD energy to total self-generation energy ratio*	25%	100%

* The results for these two ratios are discussed in Section 3.3

Parasitic Energy Factor

The average weighted parasitic energy was found to be 3.8 percent and is shown by project type in Figure 3.5. The parasitic energy of New Power Generation projects had an engineering estimate with annual review during M&V ranging from 1 percent to over 9 percent of generation energy. However, the parasitic energy factor was not applied to Rebuilt Turbo Generator projects. The evaluation found that the default assumption of 3 percent of gross generation energy was appropriate for Rebuilt Turbo Generator projects.

Figure 3.5 Parasitic Energy Factor by Project and Project Type



Peak-to-Energy Factor

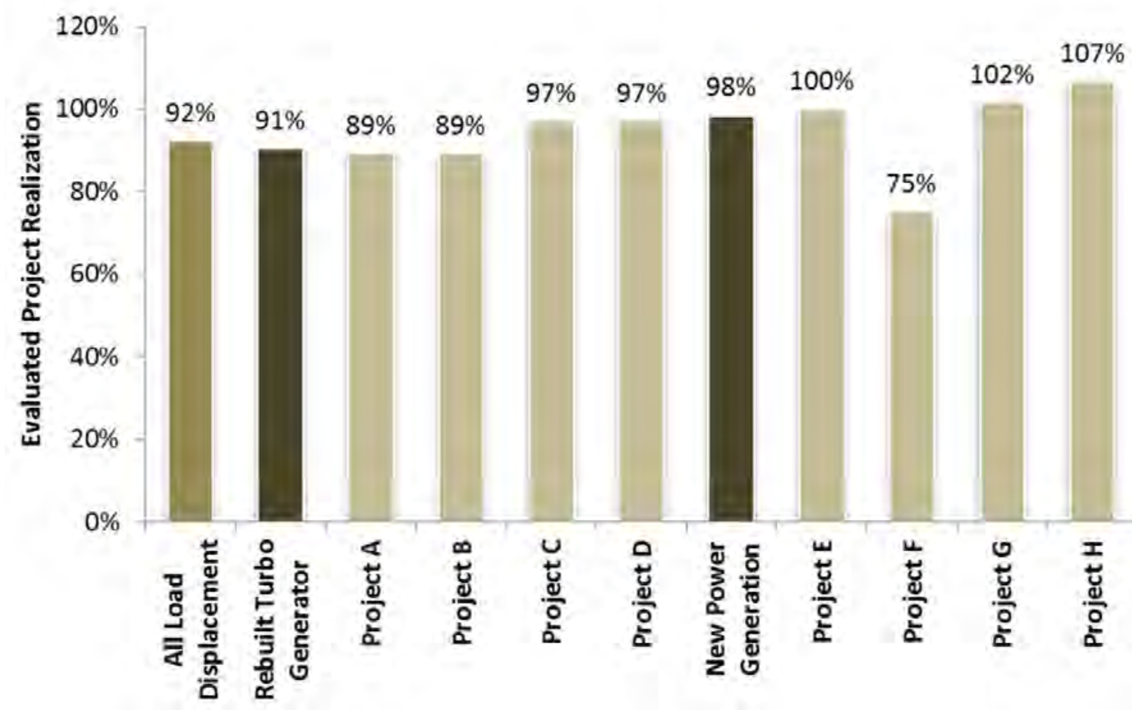
The peak-to-energy factor for net generation energy was assumed to be the same as estimated for gross generation energy which was estimated in Objective 1 for a weighted average of all eight load displacement projects of 0.126 MW per GWh. This assumed that generation energy and parasitic energy have the same load shape.

The peak demand impact of the load displacement projects was significant in magnitude and coincided with the BC Hydro system peak, and yet it was found that these projects potentially have additional capacity to ramp up electricity output. This potential capacity could be utilized as a capacity-focused DSM or demand response resource in the future. The evaluation estimated a theoretical potential to increase the peak-to-energy factor to 0.2 MW per GWh, for an additional 18 MW of peak demand impact for all CHP systems with a load displacement project. The ability to ramp up these combined heat and power systems during peak demand periods is dependent on a number of factors that may require further investigation, including the ability to control the generation rapidly and the ability of the host site to use the captured heat needed to increase the integration of these distributed energy resources onto the grid.

Project Realization

The project realization is the ratio of evaluated net energy generation to the expected generation energy, which is the contracted generation energy of the incentive agreement. Project realization is shown by project and aggregated by project type in the following figure.

Figure 3.6 Project Realization by Project and Project Type



Typical project realization was found to be 92 percent which means load displacement projects produced less than their expected generation energy. This is primarily due to the parasitic energy factor of Rebuilt Turbo Generator projects and the lower than expected aggregate utilization factor. New Power Generation projects also did not achieve their expected generation energy because of one project with lower than expected utilization factor.

The generation energy resulting from these projects is reported each fiscal year and adjusted using the most recent estimate as the best available estimate of net generation energy. In summary, the load displacement initiative included eight projects between F2012 and F2018 and achieved 96 percent of the reported generation energy and 101 percent of the reported peak demand impact. The results by fiscal year are given in the following table.

Table.3.4. Summary of Net Generation Energy and Peak Demand Impact

Fiscal Year	Net Generation Energy (GWh/yr)		Net Peak Demand Impact (MW)	
	Reported	Evaluated	Reported	Evaluated
F2012	254	162	30	20
F2013	254	176	30	22
F2014	195	176	23	22
F2015	215	196	25	25
F2016	271	253	32	32
F2017	260	253	30	32
F2018	262	253	31	32

Year over year reporting of load displacement generation energy improved as the operation of the self-generating systems reached closer to steady-state operation. However, there was a time lag because M&V results for a given reporting year only became available after fiscal year-end and were then used as the best available estimate for the next year. Considering this time lag in reporting variations in performance between fiscal years, the evaluated net generation energy was estimated, on average, to have achieved 96 percent of the reported generation energy. The variance is primarily due to inconsistency in the reporting of Rebuilt Turbo Generator projects, using their expected generation energy instead of the actual generation energy, and the lack of accounting of parasitic energy in reported savings for these projects. If the reported generation energy were adjusted for actual generation energy and estimated parasitic energy, the overall variance between reported and evaluated net generation energy of all eight load displacement projects would be reduced to less than one percent.

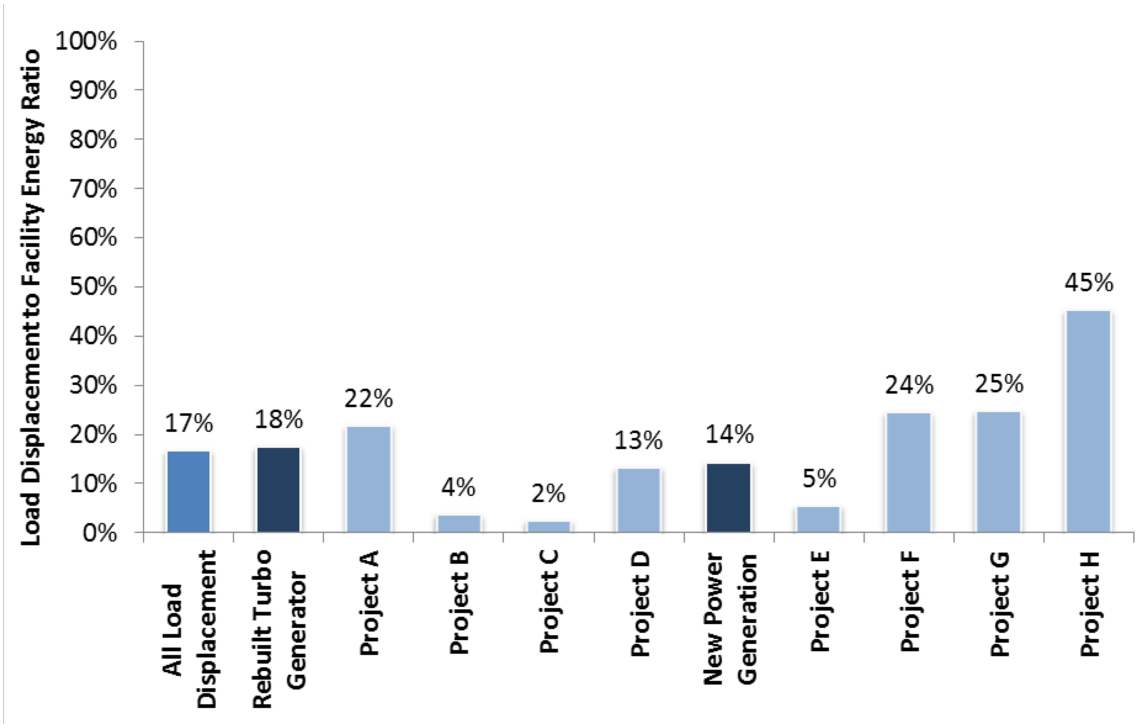
3.3 Results for Other Relevant Factors

The evaluation included other relevant factors as performance metrics for design and development of future load displacement projects. These include the load displacement to facility energy ratio and the load displacement to total self-generation energy ratio. The findings are described below.

Load Displacement to Facility Energy Ratio

The load displacement to facility energy ratio indicates the proportion of annual site energy consumption that was displaced by the load displacement project. The results are shown in the graph below for the eight projects and in aggregate by project type. This ratio ranged from 2 percent to almost 22 percent for Rebuilt Turbo Generator projects, and 5 percent to 45 percent for New Power Generation projects. The weighted average for all load displacement projects was 17 percent.

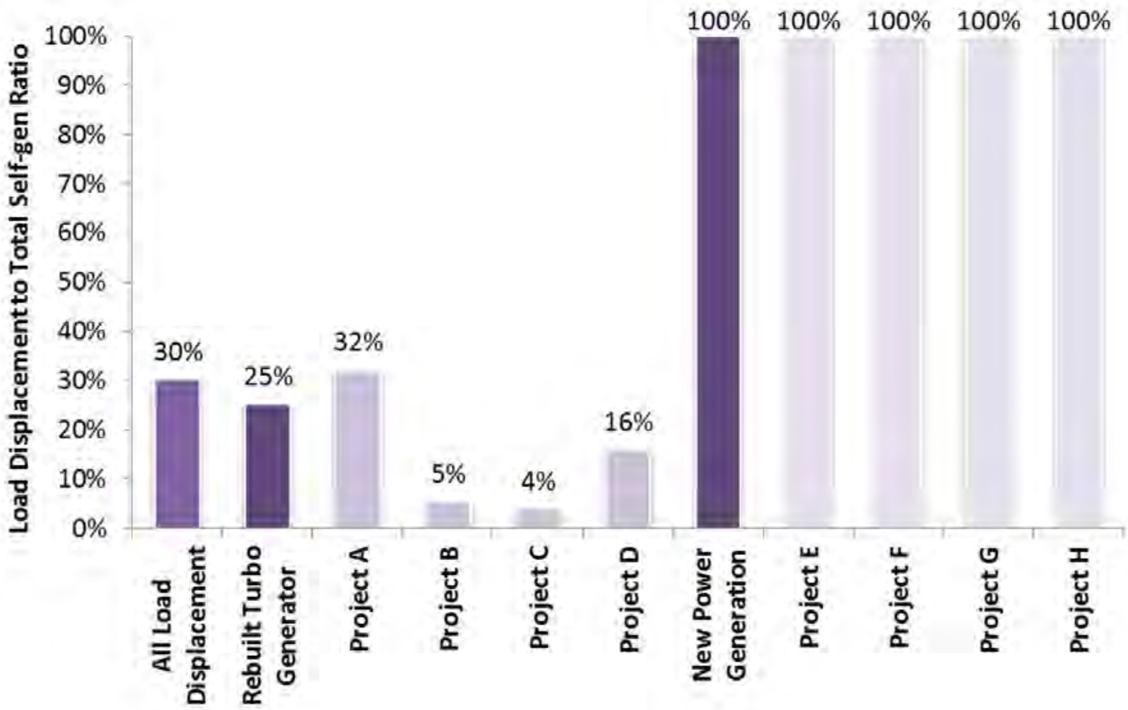
Figure 3.7 Load Displacement to Facility Energy Ratio by Project and Project Type



Load Displacement to Total Self-generation Energy Ratio

Load displacement projects of Rebuilt Turbo Generator type were found to have contributed approximately 25 percent to the total annual self-generation energy. All New Power Generation projects were at sites without previous self-generation and hence resulted in a 100% increase in self-generation at that site. This is illustrated in Figure 3.8.

Figure 3.8 Load Displacement to Total Self-generation Energy by Project and Project Type



Persistence

The average weighted persistence of the eight load displacement projects was found to be 16 years based on the BC Hydro Persistence Standard[14]. The BC Hydro Persistence Standard prescribes persistence and effective measure life of 20 years for New Power Generation and 15 years for Rebuilt Turbo Generator projects, although it includes provisions for adjusting these values based on annual review of generation energy and the terms of load displacement contracts. The evaluation found that project persistence for 3 projects (two Rebuilt Turbo Generator and one New Power Generation project) was adjusted to match the terms of the contract for the project.

3.4 Limitations

The following limitations were recognized in this evaluation.

1. Projects are complex, large, and unique, making it difficult to compare performance between projects. Although each project undergoes custom energy studies and extensive engineering reviews before implementation, the actual project operation and performance can vary over the project persistence, such that the evaluated project performance over the entire persistence period is difficult to predict based on past performance alone. However, this risk is substantially reduced over time and eventually eliminated due to the annual M&V and engineering review process.

[14]BC Hydro DSM Standard: Effective Measure Life and Persistence – Revision 10, June 2016

2. Confidence and precision of the performance characteristics were not statistically tested for their significance because all eight projects were included in the evaluation and no extrapolation was required.
3. Parasitic energy was mostly based on engineering estimates with spot measurements when available. No measurements of parasitic energy of incremental Rebuilt Turbo Generator projects were considered feasible, so that a default assumption of industry standard practice was used. However, this assumed that the parasitic load and energy is directly proportional to the variation in generation energy.
4. Other performance characteristics typical of combined heat and power projects, as well as variability in plant production, may impact the program performance but were not evaluated as there was no program need or requirement.
5. Customer satisfaction and experience was not evaluated because the program has ended and no future load displacement program is under consideration at this time.

4.0 Findings and Recommendations

Findings and recommendations are presented below.

4.1 Findings

1. Eight load displacement projects were evaluated for a total of 263 GWh per year in gross generation energy and 253 GWh per year in net generation energy. This resulted in 33 MW of gross peak demand impact and 32 MW of net peak demand impact.
2. Seven of the eight load displacement projects ranged from 1 MW to 5 MW in size and one exceeded 25 MW in rated capacity. Seven of the load displacement projects were considered CHP and used biomass and bioenergy as the primary energy source.
3. The four Rebuilt Turbo Generator projects were found to have average availability, capacity and utilization factors of 94 percent, 78 percent and 72 percent respectively. The other four projects were of the New Power Generation type and were found to have average availability, capacity and utilization factors of 91 percent, 84 percent and 76 percent respectively.
4. The load displacement project realization ranged from 75 percent to 107 percent, with a weighted average project realization rate of 91 percent for Rebuilt Turbo Generator and 98 percent for New Power Generation type projects. The overall program realization rate was 92 percent.
5. All projects undergo annual verification of the generation energy. Rebuilt Turbo Generator load displacement projects had verification of actual gross generation energy recorded by BC Hydro Contract Management, whereas New Power Generation type projects underwent annual measurement and verification activities, recording both gross and net generation energy recorded. The reported generation energy is adjusted yearly based on this annual review for all New Power Generation type projects but not for Rebuilt Turbo Generator type projects.
6. The generation energy provided in the customer's annual CBL Statements was found to be the best available estimate for projects without annual measurement and verification. These generation energy records explain most of the variance between reported and evaluated gross generation energy for Rebuilt Turbo Generator type load displacement projects.
7. The peak-to-energy factor was found to be 8 percent higher than the industrial rate class average because six of the eight projects generated more power during BC Hydro's system winter peak because of higher availability factors in winter months. Generator shutdowns and annual maintenance periods which decreased overall availability were observed to be typically in the spring and summer months. Two projects had peak-to-energy factor lower than the industrial rate class average because of higher process heat requirements in winter.
8. Parasitic energy is the difference between gross and net generation energy and was evaluated at 3 percent for Rebuilt Turbo Generator projects and 6.5 percent for New Power Generation projects. New Power Generation projects have more auxiliary energy requirements than incremental generation projects from Rebuilt Turbo Generators. The parasitic energy explains most of the difference between reported and evaluated net generation energy.
9. The average weighted persistence of load displacement projects was estimated to be 16 years and ranging from 10 years to 20 years. The BC Hydro Persistence Standard indicates 20 years persistence for New Power Generation type projects and 15 years persistence for Rebuilt Turbo Generator

projects. Any changes to generation energy and persistence are captured in the annual M&V and engineering review process.

10. The evaluation found evidence of continuous improvement of the utilization factor of three New Power Generation load displacement projects through the annual review and M&V process. Project underperformance was observed due to restriction in condensing capacity, fuel supply, and electrical metering issues that were identified and corrected during the first three years of operating the load displacement projects.

4.2 Recommendations

The following recommendations are for the BC Hydro Load Displacement initiative managers based on the findings of this evaluation.

1. Continue to conduct annual review and measurement and verification of all load displacement projects for reporting of actual net generation energy per fiscal year.
2. The program should use the generation energy from customer's annual CBL Statements as the best available estimate when annual measurement and verification results are not available. These apply to Rebuilt Turbo Generator type projects at large industrial customer sites with transmission service and are on the stepped rate (RS1823B).
3. The program should apply a 3% reduction to the gross generation energy for projects without an engineering estimate of parasitic energy, i.e., load displacement projects of Rebuilt Turbo Generator type.

5.0 Conclusions

BC Hydro’s load displacement initiatives achieved 92 percent of expected generation energy during fiscal years F2012 to F2018. The New Power Generation projects achieved 98 percent due to continuous improvement of project performance, whereas the Rebuilt Turbo Generator projects achieved 91 percent due to underestimated utilization factor and parasitic energy. The evaluated net generation energy of both types of load displacement projects was found to produce an equivalent reduction in site energy purchases.

Evaluation Oversight Committee Sign-Off

BC Hydro's Evaluation Oversight Committee is made up of DSM stakeholders from various parts of the company and is mandated to ensure that BC Hydro's DSM evaluations are objective, unbiased and of sufficient quality.

The Evaluation of the *Power Smart Partners - Load Displacement Initiatives Impact Evaluation: F2012-F2018* meets the following criteria for approval by the Evaluation Oversight Committee:

- The evaluation complied with the defined scope.
- The evaluation methodology is appropriate given the available resources at the time of the evaluation.
- The evaluation results are reasonable given the available data and resources at the time of the evaluation.

______________________________ April 8, 2020

Serina Grahn, Finance Manager, Business Services Date

Evaluation Oversight Committee Chair

References

California Public Utilities Commission (2014). 2012 *Self-Generation Incentive Program Impact Evaluation and Program Outlook.*

California Public Utilities Commission (2011). *CPUC Self-Generation Incentive Program Tenth-Year Impact Evaluation Final Report*

California Public Utilities Commission (2010). *Self-Generation Incentive Program Combined Heat and Power Performance Investigation.*

Efficiency Valuation Organization (October, 2016). *Core Concepts. International Performance Measurement and Verification Protocol.*

New York State Energy Research and Development Authority (2010). *Distributed Generation-Combined Heat and Power DRAFT Evaluation, Measurement and Verification Plan.*

National Renewable Energy Laboratory (NREL), The Uniform Methods Project: Methods for Determining Energy-Efficiency Savings for Specific Measures*, Chapter 23: Combined Heat and Power, 2016. NREL/ SR-7A40-67307*.

U.S. Environmental Protection Agency Combined Heat and Power Partnership (2017). *Catalog of CHP Technologies*.

Abbreviations and Glossary

Customer Baseline Load (CBL): an energy quantity, established in accordance with principles described in the Transmission Service Rate (Tariff Supplement 74) that is intended to be representative of a customer's normal historic annual electricity consumption. An annual CBL Statement is issued by BC Hydro for each customer on stepped rate schedule (RS1823B) that includes all adjustments to a customer's energy bill for the purpose of CBL administration.

Demand Side Management (DSM): The definition of Demand Side Management is the same as the definition of "demand-side measures" set out in section 1 of the Clean Energy Act, which is "a rate, measure, action or program undertaken; (a) to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand, but does not include (d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or (e) any rate, measure, action or program prescribed".

Electricity Purchase Agreement (EPA): An agreement between BC Hydro and the customer establishing the terms and conditions under which BC Hydro purchases self-generation output produced at the customer's Contracted Generating Unit.

Expected Generation Energy: Estimate of generation energy that is net of parasitic energy and based on the initial engineering estimates. These estimates represent the unverified net electricity impacts of the load displacement project.

Generator Baseline (GBL): The customer's annual, seasonal, monthly or hourly contractual commitment for self-supply from a Contracted Generating Unit that must be satisfied to obtain financial payments.

Gigawatt Hour (GWh): One billion watt-hours; one million kilowatt hours.

Gross Generation Energy: The electrical energy produced by the load displacement project, not all of which is usable to offset the customer's energy purchases.

Load Displacement Agreement (LDA): An agreement between BC Hydro and a customer establishing the terms and conditions under which BC Hydro provides the customer with a financial incentive to make self-generation output for self-supply from a Contracted Generating Unit.

Load Displacement Project: Projects for industrial, commercial and institutional customers that received BC Hydro funding and program support to generate their own electricity for self-supply and offset electricity purchases from BC Hydro.

Net Generation Energy: The generation energy for actual use by the customer. It is estimated by the gross generation energy minus the parasitic energy.

New Power Generation: Type of load displacement project that includes a New Power Generating system of various technologies (internal combustion engine, organic Rankine cycle, combined cycle, boiler steam turbo-generator, combined heat and power, fuel cell, solar).

Parasitic Energy: The electrical energy that is required for the operation of the load displacement project. This is due to a variety of equipment associated with service of the load displacement project, for example, pumps and fans for moving fluids or gases, but not including generator losses.

Peak demand impact: The reduction in demand (MW) that occurs during BC Hydro's system peak hours (from 5 pm-7 pm, Monday through Friday, December through February) as a result of the load displacement project.

Persistence: Refers to how long the generation energy is expected to be attributable to the demand side management activity.

Realization Rate: The ratio of net generation energy adjusted during measurement and verification and evaluation review to the expect generation energy.

Rebuilt Turbo Generator: Type of load displacement project when the turbine casing, turbine blades, turbine shaft, generator windings, etc., are refurbished to improve generation performance, condition and life of the used turbo generator. Usually a lower persistence is given to a Rebuilt Turbo Generator compared to a new turbo generator type projects.

Renewable Natural Gas: Renewable natural gas is derived from biogas, which is produced from decomposing organic waste from landfills, agricultural waste and wastewater from treatment facilities.

Reported Savings: Estimate of net generation energy being recorded in the program tracking database for a given fiscal year. Reported generation energy is based on best information available from technical review of the initial engineering estimate, post-implementation review of documentation and/or inspection, measurement and verification results, or other information sources such as CBL Statements.

Appendix A Results Summary

The purpose of this appendix is to summarize key numerical results from the Load Displacement Initiatives impact evaluation for the period of F2012 to F2018. The following table present the savings summary.

Table A.1. Energy and Demand Savings

	Reported	Evaluated Gross	Evaluated Net
Generation energy (GWh/yr)	271	263	253
Peak demand impact (MW)	32	34	32

The following table presents the key results and findings.

Table A.2. Key Results of Load Displacement Projects for F2012-F2018

Key parameter and relevant factors	Group1: Rebuilt Turbo Generator	Group 2: New Power Generation
Number of projects	4	4
Rated Capacity (MW)	32	9
Expected Generation Energy (GWh/yr)	218	56
Reported Generation Energy (GWh/yr)	218	52
Evaluated Gross Generation Energy (GWh/yr)	204	59
Evaluated Net Generation Energy (GWh/yr)	198	55
Evaluated Net Peak Demand Impact (MW)	25.5	6.5
Parasitic Energy Factor	3%	6.5%
Realization Rate	91%	98%
Peak-to-Energy Factor	0.129	0.117
Availability Factor	93%	91%
Capacity Factor	77%	84%
Utilization Factor	72%	76%
Load Displacement to Facility Energy Ratio	18%	14%
Load Displacement to Total Self-generation Energy Ratio	25%	100%
Free ridership (not evaluated; deemed zero for large LD projects)	0; not evaluated	0; not evaluated
Spillover (not evaluated; deemed zero for large LD projects)	0; not evaluated	0; not evaluated
Average Weighted Persistence (years)	16	19
Variance Factor (evaluated net as % of reported generation energy)	91%	106%
Variance Energy (GWh/yr)	-21	+3
Reason for variance: 1. Average adjustment for actual generation from CBL Statements (GWh/yr) 2. Average adjustment for parasitic energy (GWh/yr)	 -15 GWh/yr -6 GWh/yr	

Appendix B Advisor Memos on Evaluation Report

Advisory Memo on Evaluation Report

March 27, 2020

To: BC Hydro
333 Dunsmuir St.
Vancouver, B.C.
V6B 5R3

From: Pierre Baillargeon
Evaluation Advisor
Vice President Econoler
160 Saint-Paul St., Suite 200
Quebec City, QC GIK 3W1

Re: Load Displacement Program Evaluation

Dear Madam or Sir,

This advisory memo summarizes the opinions of the evaluation advisor on the evaluation work performed by the BC Hydro evaluation team for the abovementioned program. It takes into consideration the initial comments and answers from the evaluation team, which were incorporated into the final version of the evaluation report when appropriate.

Overall appreciation of the report:

- Very good report, with clear and comprehensive explanations of the evaluation steps. The results highlight the key points demonstrating the achievement of the initiative.
- The advisor commends the evaluation team for the openness and transparency during the whole review process. Exchanges with the BC Hydro team were excellent. They provided clear and precise answers to all questions and additional information whenever necessary.

1. What is your assessment of the **quality of the research design**? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?
   - The quality of the research design is excellent, the evaluation objectives and research questions are clear and the report answers those questions.

2. What is your assessment of the **quality of the input data**? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?

- The program evaluation is based on high-quality data. Mainly emetering, customer billing and customer baseline load (CBL).

3. What is your assessment of the **quality of the analytical methods**? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?
   - The analytical method was good and appropriate for the type of evaluation conducted. The new construction component relied on well-known M&V approaches.
   - All equations used for the peak-to-energy factor, capacity factor, availability factor, utilization factor, etc., follow sound engineering principles.
   - The evaluation of a peak-to-energy factor for each site individually provides a better estimate of overall peak effects.
   - The assumption used to estimate parasitic loads (as proportional to generation) was appropriate, considering the small effect of those loads.

4. How does the methodology **compare to common industry practice** for evaluations of similar initiatives?
   - Combining the M&V and billing analysis approaches is generally consistent with best practices to establish load displacement program impacts.

5. What are your **suggestions for future evaluations** of this DSM initiative?
   - The only recommendation is to explore the untapped potential for LD from the implemented projects, which was estimated at approximately 18 MW.

6. Do you have any other comments that you would like to make?
   - No, this evaluation report is very good. Well done.

Advisor Memo on Evaluation Report

March 25, 2020

To: BC Hydro

From: Rafael Friedmann
EOC Evaluation Advisor
Oakland, California

Re: Load Displacement Program Evaluation

1. What is your assessment of the quality of the research design? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?
    - The research design was appropriate for the task at hand.

2. What is your assessment of the quality of the input data? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?
    - Data is adequate and based on a variety of sources, particularly billing and project M&V.

3. What is your assessment of the quality of the analytical methods? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?
    - Methods are straightforward and aligned with the results sought.
    - One project had major commissioning issues that delayed "steady-state" operations and thus, its impact results
    - Persistence based on BCH standards. These are based on engineering estimates; not evaluated due to the long life (16 or more years).

4. How does the methodology compare to common industry practice for evaluations of similar initiatives?
    - Unaware of similar research elsewhere as this is a unique program to my knowledge.

5. What are your suggestions for future evaluations of this DSM initiative?
    - Understand the program is discontinued. If it were to be started again, suggest that more research be done to explore further the apparently significant, untapped opportunities for further Load Displacement
    - Consider tracking persistence if deemed important given the size of some of these projects

6. Do you have any other comments that you would like to make?
    - Well written and comprehensive report

Appendix C Project Details

The following series of figures show the distribution of generation energy of the load displacement projects by project type, technology type, primary energy source, and combined heat and power applications.

Figure C.1. Distribution of Generation Energy by Project Type

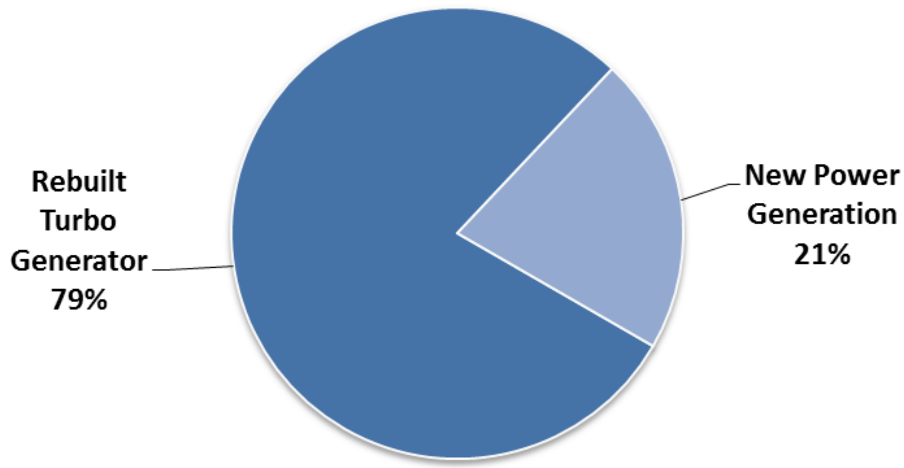


Figure C.2. Distribution of Generation Energy by Primary Energy Source

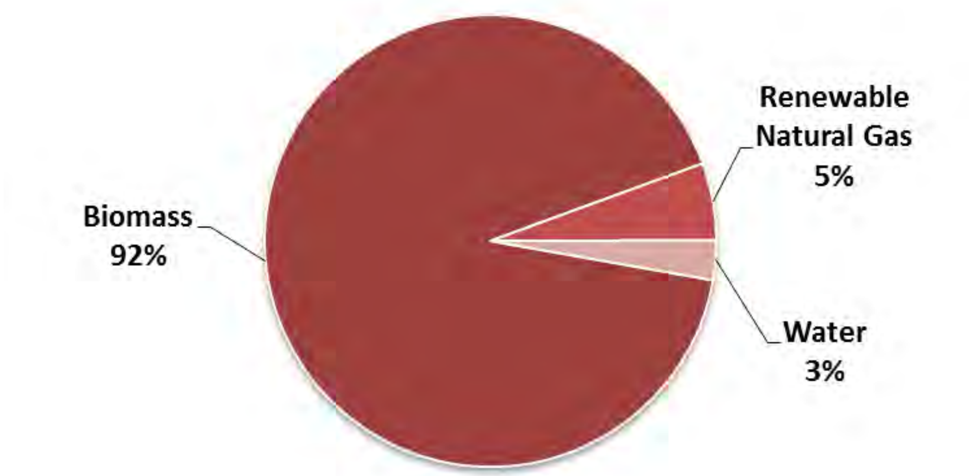


Figure C.3. Distribution of Generation Energy by Technology Type

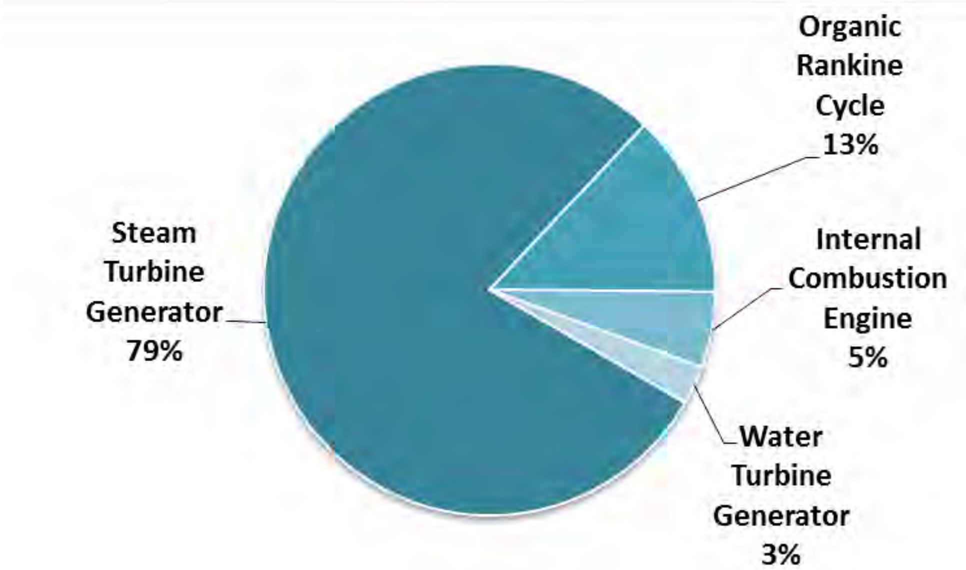
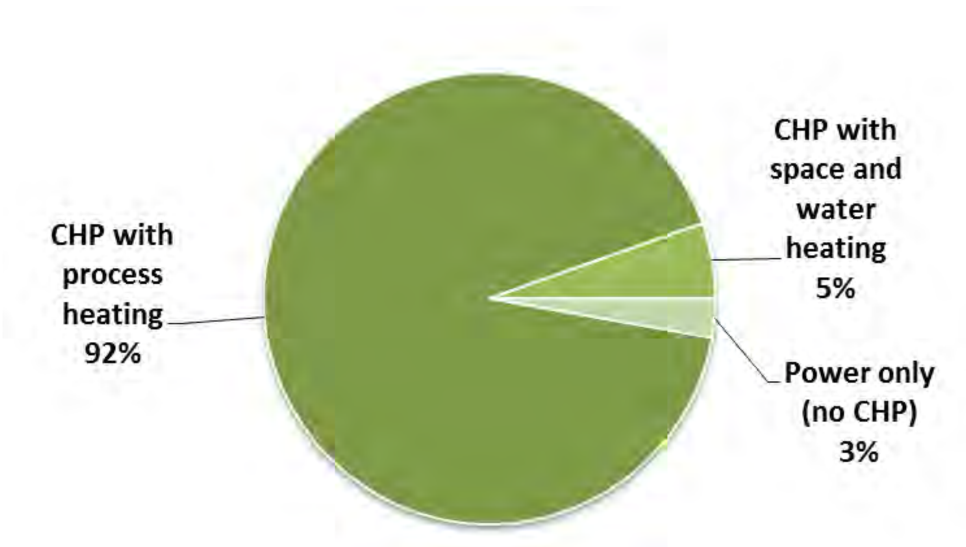


Figure C.4. Distribution of Generation Energy by Combined Heat and Power (CHP) Application



Appendix D Result Details

The following figures illustrate the distribution of relevant factors of the load displacement projects by fiscal year from F2012 through F2018. Since the last load displacement projects in this evaluation period were installed in F2016, the results for F2017 and F2018 are trending the continuing operation and performance of all load displacement projects.

Figure D.1. Availability Factor by Project, Project Type and Fiscal Year

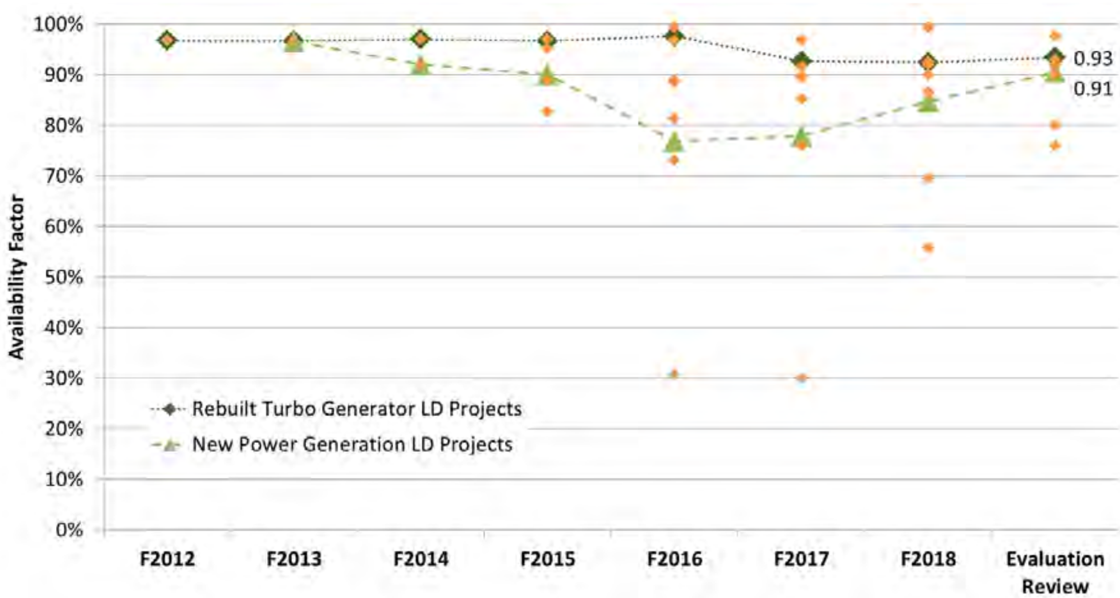


Figure D.2. Capacity Factor by Project, Project Type and Fiscal Year

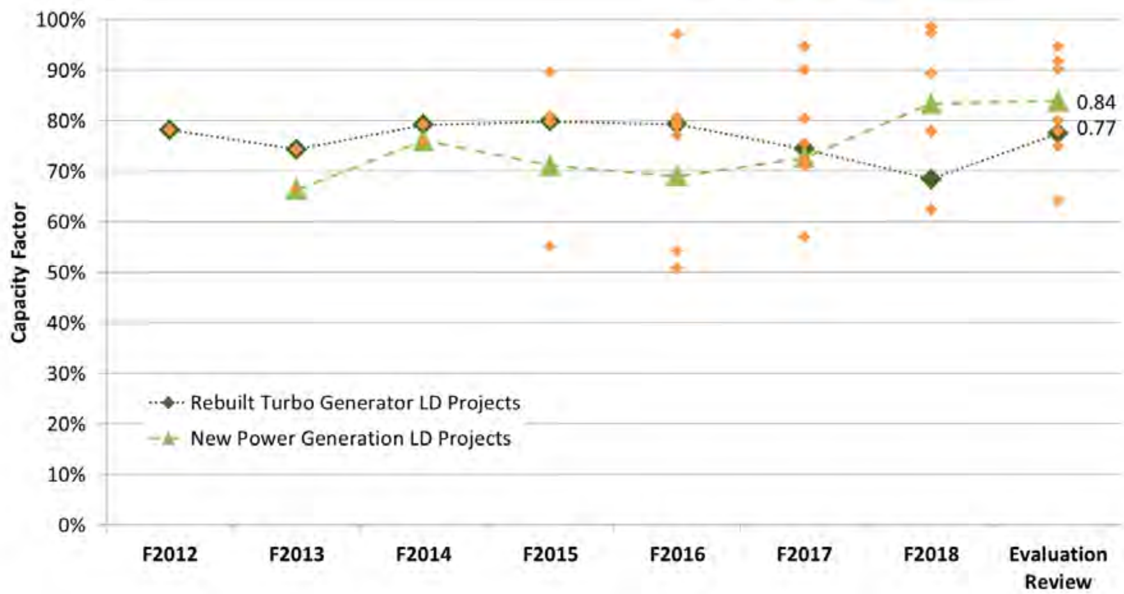


Figure E.3. Utilization Factor by Project, Project Type and Fiscal Year

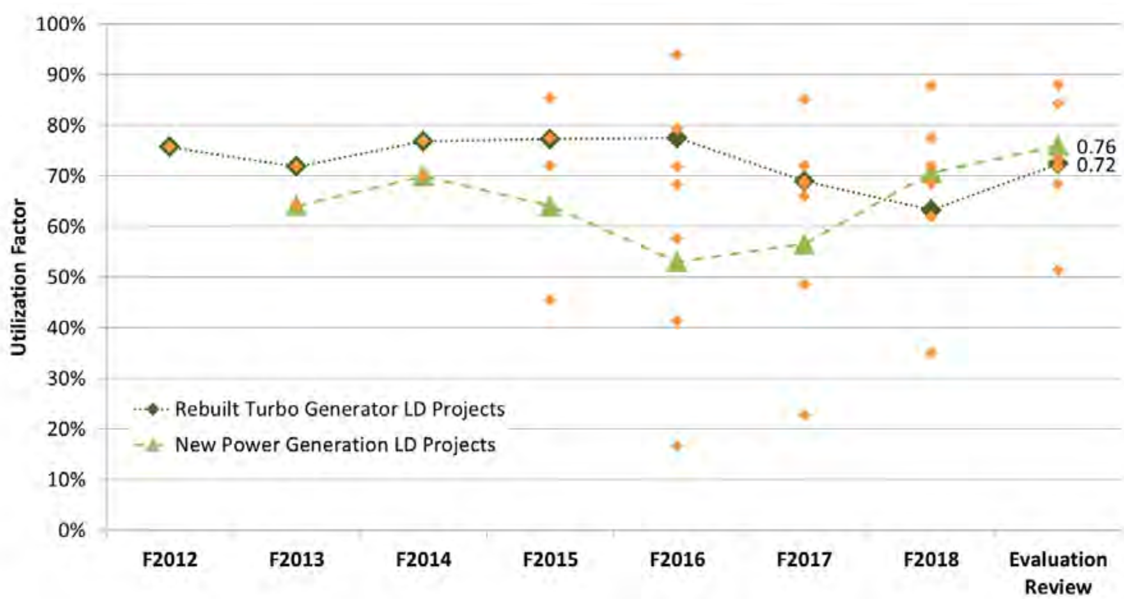


Figure D.4. Parasitic Energy Factor by Project, Project Type and Fiscal Year

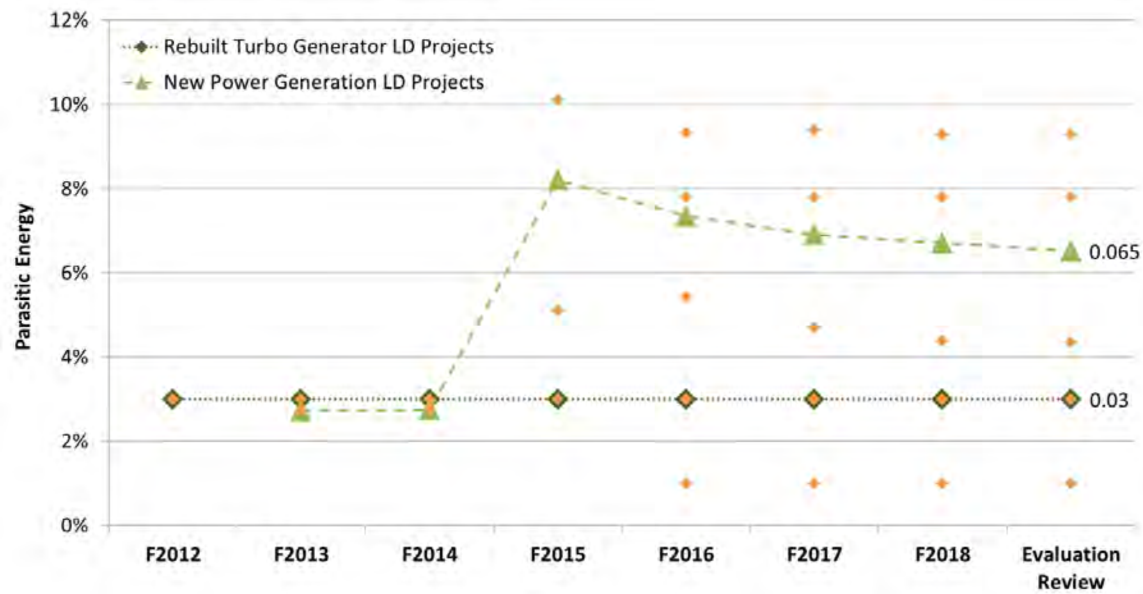
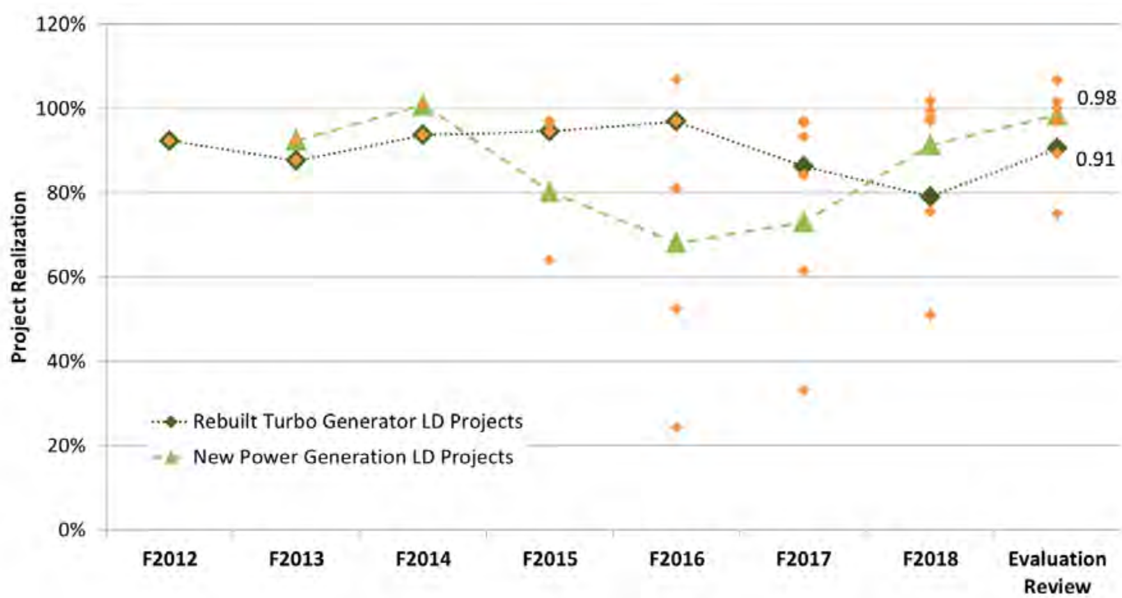


Figure D.5. Project Realization by Project, Project Type and Fiscal Year



BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

Appendix BB

Greenhouse Gas Management Plan

Table of Contents

List of Figures

List of Tables

1 Executive Summary

Climate change is one of the most challenging global issues that we face as a society today. Addressing climate change and supporting the climate actions and targets of government is a priority for BC Hydro. We have developed a Greenhouse Gas (**GHG**) Management Plan that aligns with the Government of B.C.'s CleanBC objectives.

Our GHG Management Plan is forecasting to achieve a reduction in our emissions of 52 per cent by 2025 and 71 per cent by 2030, exceeding the CleanBC targets of 16 per cent and 40 per cent respectively. It connects to and supports key related strategies such as our Environment Strategy, The *United Nations Declaration on the Rights of Indigenous Peoples* (**UNDRIP**), and our Electrification Plan and it is designed with affordability and compliance as key principles.

Our investment in the GHG Management Plan over the fiscal 2022 to fiscal 2030 period will be made through our existing budgets and prioritization processes. Our plan provides clear measures of progress against internally set targets and those that are set in regulation and it demonstrates our commitment to contributing to a healthy environment for the long-term.

2 Our GHG Management Plan Aligns with the Government of B.C.'s Climate Goals and CleanBC

As a Crown Corporation we have an important role in supporting the climate goals of government. BC Hydro's Mandate Letter provided direction to ensure that our organization's operations align to the Government of B.C.'s climate strategy CleanBC, and our Five-Year Strategy reflects our direction to seek reductions in our GHG emissions where feasible and affordable.

Our Electrification Plan is a central support to the Government of B.C.'s climate action plan and will have a broad and significant effect on GHG reductions in our province by supporting our customers to electrify. Our GHG Management Plan is focused on our own operations and further demonstrates our support for actions leading to climate change mitigation.

Under the *Climate Change Accountability Act*, the Government of B.C. has legislated province-wide targets for reducing GHG emissions as follows:

- 16 per cent below 2007 levels by 2025;
- 40 per cent by 2030;
- 60 per cent by 2040; and
- 80 per cent by 2050.

In addition to the overall targets, the Government of B.C. has recently published sectoral targets for Transportation, Oil and Gas, Buildings and Communities and Industry. For our GHG Management Plan we are aligning to the provincial target range for the Industry sector, which has been set at an overall 38 to 43 per cent reduction by 2030.

3 Our GHG Management Plan Aligns with and Supports Related Strategies

Our GHG Management Plan aligns with and supports important BC Hydro and Government of B.C. strategies, including:

- **BC Hydro's Environment Strategy and Principles** – As leaders in managing valuable public resources, our decisions matter. Our environment strategy includes an objective to support climate actions and targets set out by government. Our GHG Management Plan is a key area of focus and one way we are contributing to a healthy environment for the long-term;

- **UNDRIP Implementation** – Reducing diesel use in BC Hydro's Non-Integrated Areas (**NIAs**) and moving to cleaner sources of energy supports our commitment to reconciliation and helps meet objectives under UNDRIP. Many of these communities are interested in reducing diesel use for the associated environmental benefits and/or as a path to energy self-sufficiency. The goals in our Five-Year Strategy support these aims and the UNDRIP principles that underlie community interests;
- **Affordability** – Our plan reflects some GHG reduction actions that are already included in our planned capital and operating budgets. Reducing fossil fuel consumption will directly lower costs related to fuel purchases and will avoid future cost increases from the escalating carbon tax. In addition, this will lead to savings in our annual carbon offset payment which is calculated at \$25/tCO_2e for our fleet and building emissions. Reducing our corporate air travel is associated with significant annual savings in both capital and operating dollars;
- **Electrification Plan** – Demonstrating leadership through selected electrification of our own assets is an integral element of our GHG Management Plan. In addition to taking actions in our own operations, BC Hydro is supporting our customers in shifting from natural gas to electricity. This shift toward clean electricity will help lower overall provincial GHG emissions. These reductions are anticipated to be as great, or greater, than those achieved through our internal actions. Quantifying the reductions facilitated by our customer electrification is included in our Five-Year Strategy; and
- **Clean Electricity and our Integrated Resource Plan (IRP)** – As our province shifts toward a cleaner future, gas-fired thermal generation will be reduced over time. Our draft 2021 IRP assumes a reduced reliance on our thermal generation Independent Power Producers (**IPPs**), and this is reflected in our GHG Management Plan.

4 Treatment of Imports and Exports

Through our trade of clean electricity, we affect GHG emissions beyond our borders. Quantification of GHG emissions related to trade is outside the scope of this GHG Management Plan. Powerex reports GHGs associated with gross scheduled imports of electricity to the provincial government under the *GHG Industrial Reporting and Control Act*.

5 Our GHG Plan was Developed with a Consistent Set of Objectives

Our GHG reduction forecast is inclusive of all categories of GHG emissions related to our buildings, fleet, Sulphur Hexafluoride (**SF_6**) and Carbon Tetrafluoride (**CF_4**) insulating gases and diesel and thermal generation, as well as indirect emissions related to IPPs and corporate air travel. While we do not directly own and operate IPPs, we may influence their operations through our decisions related to their Electricity Purchase Agreements (**EPAs**) with BC Hydro. The same holds true on our use of corporate air travel.

We examined opportunities to reduce emissions in all categories and developed a plan for each category based on these objectives:

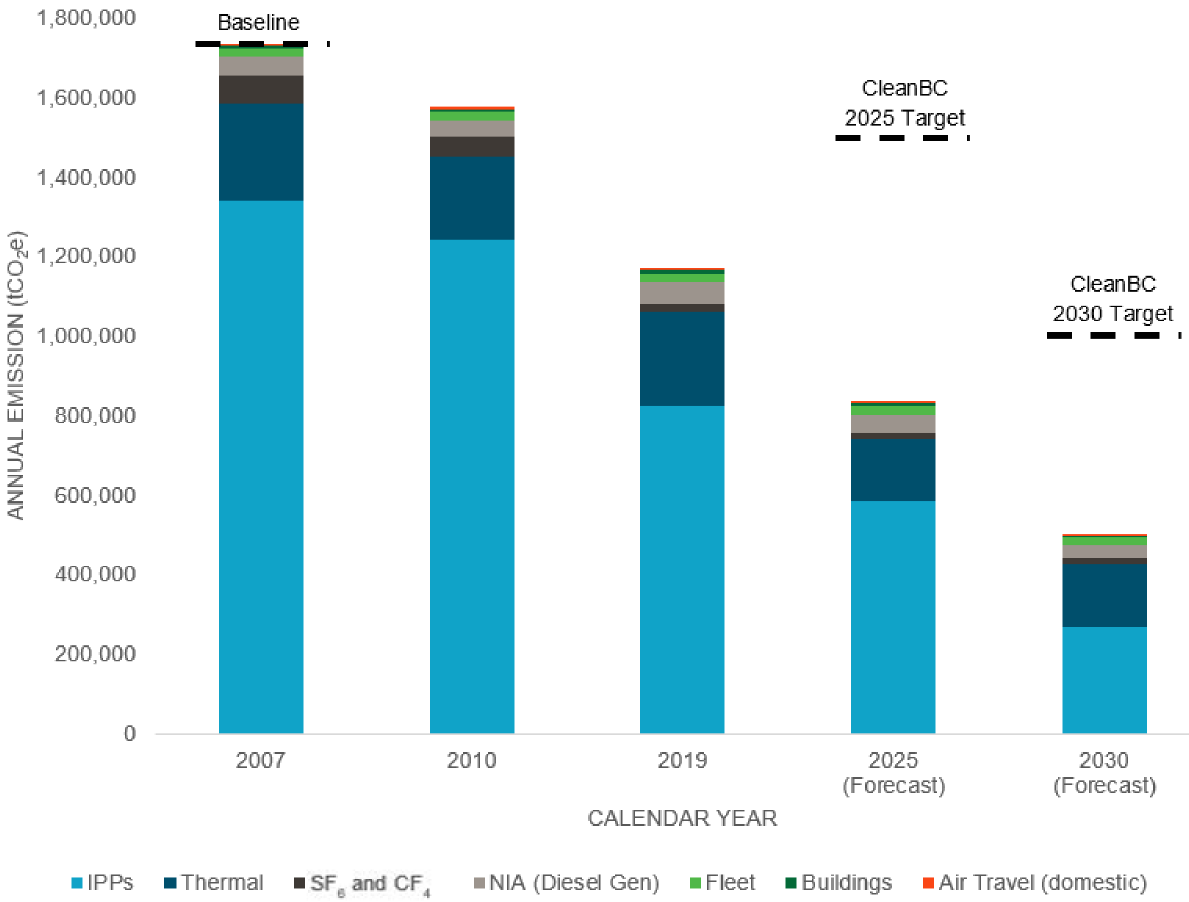
- Focus on compliance and achieving the overall Industry reduction target as set out by the Government of B.C.;
- Comparative return on investment based on the potential GHG reduction weighed against affordability, technical feasibility, market availability and ease of adoption;
- Ensure we maintain a fleet suitable to our organization while pursuing Electric Vehicles (**EVs**) that make sense given our role as a first responder;

- Include existing commitment to develop a plan for reducing diesel generation in NIAs;
- Consider the effect of the escalating Federal carbon tax on our operations; and
- Ensure that the GHG reductions are hard-wired to the extent possible and do not rely on employee behaviors to realize.

6 Our GHG Management Plan Forecasts a Reduction in Emissions of 52 per cent by 2025 and 71 per cent by 2030

The chart and table below show our GHG forecast for 2025 and 2030 against a 2007 baseline. As shown in Figure BB-1, our GHG emissions have decreased since 2007, primarily due to decisions we have made to reduce our thermal operations and reliance on natural gas IPPs. Our forecast assumes a further decrease in our thermal emissions and further decreased reliance on natural gas IPPs. By 2025 we anticipate a 52 per cent reduction from baseline levels versus a 16 per cent target, and in 2030 we anticipate a 71 per cent reduction versus a 40 per cent target. As shown in Table BB-1, GHG reductions will be achieved in all categories, and will be most significant in SF_6 and CF_4, thermal operations, and IPPs.

Figure BB-1 BC Hydro Annual GHG Emissions by Category. Tonnes Equivalent CO_2 (tCO_2e)



Notes:

1. Fleet and buildings baseline is based on calendar year 2010 as calendar year 2007 data is unavailable.
2. Air Travel (domestic) baseline is based on calendar year 2019 as calendar year 2007 data is unavailable.
3. IPPs baseline includes Island Generation, which is operated as a dispatchable facility and hence the hours of operation may significantly vary from year to year

Table BB-1 GHG Forecast by Category

		2019	2025		2030	
GHG Category	Baseline tCO_2e[1,2]	Actual tCO_2e	BC Hydro Forecast tCO_2e	BC Hydro Forecast Reduction (%)	BC Hydro Forecast tCO_2e	BC Hydro Forecast Reduction (%)
Buildings[3]	7,400	10,800	6,300	15	4,600	38
Fleet[3]	22,300	22,100	22,100	1	19,700	12
SF_6 and CF_4	70,400	22,000	15,000	79	15,000	79
NIA (Diesel Gen)[4]	46,300	52,100	44,100	5	30,400[5]	34
Thermal	246,000	235,000	157,000	36	155,000	37
IPPs	1,340,000	826,000	585,000	56	270,000	80
Air Travel (domestic)[5]	2,400	2,400	1,400	42	1,400	42
Totals	**1,735,000**	**1,170,000**	**831,000**	**52**	**496,000**[5]	**71**
Government of B.C. Target (CleanBC)			**1,457,000**	**16**	**1,041,000**	**40**
Amount Plan exceeds target			**-626,000**	**36**	**-544,000**	**31**

Notes:
1. Amounts may not sum due to rounding.
2. Baseline year is 2007.
3. Fleet and buildings baseline is based on calendar year 2010 as calendar year 2007 data is unavailable.
4. NIA forecast is based on a hypothetical group of projects. The forecast may be adjusted (up or down) depending on the outcome of the NIAs – Diesel Reduction Strategy.
5. Air Travel (domestic) baseline is based on calendar year 2019 as calendar year 2007 data is unavailable.

7 Our GHG Reduction Plan Takes Action Across our Organization

The following sections summarize the areas of focus for each GHG category.

7.1 Buildings – Our plan forecasts a GHG reduction from our buildings of 15 per cent by 2025 and 38 per cent by 2030.

The BC Hydro buildings category includes head offices, district offices, NIA line offices, Site C worker accommodation, townsites and leased space. GHG emissions result from the consumption of energy to operate the buildings including heating, cooling, lighting and plug loads. Energy sources include electricity, natural gas, district steam (currently generated by natural gas) and propane.

A base level of GHG reduction in our buildings is part of our ongoing operations and includes planned replacement of end-of-life assets, sale of surplus properties and demolition of buildings that are end of life. Additional measures we are taking to further reduce GHG include adding an Energy Manager resource to support GHG planning for buildings, electrifying new buildings where financially and technically feasible, completing energy efficiency projects in our Edmonds and Dunsmuir office buildings, and purchasing steam produced by electricity, rather than natural gas for our Dunsmuir building when available in approximately 2024/2025. We are not planning to replace assets before end of life or require complete electrification of our existing buildings.

7.2 Fleet – We forecast a consistent level of GHG emissions from our fleet to 2025 and a 12 per cent reduction in our overall fleet emissions by 2030.

BC Hydro’s fleet contains over 3,400 assets that emit GHGs through the combustion of fuel in vehicles equipped with internal combustion engines. GHG reductions in our fleet may be achieved by replacing our internal combustion vehicles with hybrids, or EVs.

We require vehicles with proven reliability and performance when responding to outages and to maintain system reliability, and there are currently no suitable cost-effective EV options in many classes of vehicle. This will limit our adoption of EVs in some classes, particularly heavy vehicles, until suitable options are available. In the light duty class, BC Hydro has been transitioning away from gasoline and diesel vehicles toward electric and/ or hybrid alternatives with lower emissions. BC Hydro’s fleet of passenger vehicles is 60 per cent battery - electric, 6 per cent plug - in hybrid, and 28 per cent hybrid - electric. BC Hydro’s fleet of light duty trucks is 17 per cent hybrid - electric.

A base level of investment in EVs is part of the existing capital plan including replacing a portion of our fleet with hybrid pickups and SUVs through 2025 and replacing sedans with commercially available EVs where viable. We will continue to monitor pilot studies of EV bucket trucks in comparable utilities to learn from their application. After 2025, we will replace a portion of the pickup and SUV fleet with commercially available EVs and pilot medium and heavy-duty EVs that show strong potential for meeting our need for reliability, performance and responsiveness.

7.3 Corporate Air Travel - We are setting a corporate policy to maintain Corporate Air Travel at a level 40 per cent below baseline year.

Prior to 2020 and the COVID pandemic, BC Hydro's air travel emissions typically exceeded 2,100 tonnes of CO_2 per year. In 2020, during the COVID pandemic, air travel emissions were about 75 per cent less than the prior two years.

The organization has successfully adopted video-conferencing and other remote collaboration technology during the pandemic period. We are engaging with parts of the business where air travel has traditionally been highly used and working to develop a policy that will permanently reduce air travel to 40 per cent below our pre-COVID levels.

7.4 SF_6/CF_4 – We plan to maintain our level of emissions at or below the five-year 2019 average, 83 per cent below 2007 levels.

SF_6 and CF_4 are insulating and arc quenching gases used in electrical equipment. They are potent GHGs with high global warming potentials. Governance is in place to limit the amount of new SF_6/CF_4 equipment added to the system. More environmentally friendly alternatives will be selected where these are viable. It is expected we will continue to use these gases in our system for several decades even as we aim to minimize the amount of new SF_6 and CF_4 added to the system.

We have made significant progress reducing SF_6 and CF_4 emissions through targeted equipment repair and replacements over the past two decades. Reducing annual emissions further would require significant additional investment given that the heaviest leakers have been addressed.

7.5 NIA Diesel Generation – Our NIA plan will see GHG emissions lower by 5 per cent by 2025 and 34 per cent by 2030 from 2007 levels

An NIA is a community that is not connected to BC Hydro's integrated system. BC Hydro provides electrical service to 14 NIAs, each of which serves one or more communities and/or First Nations. Electricity in BC Hydro's NIAs is approximately 50 per cent clean or renewable and 50 per cent diesel generation. BC Hydro shares an interest in reducing reliance on diesel in NIAs and is developing a strategy to address NIA community interests in reducing diesel generation. Our NIAs – Diesel Reduction Strategy will pursue new renewable generation opportunities in NIAs by working with governments, clean energy industry partners and with Indigenous Communities to identify and pursue projects that are mutually beneficial and to advance reconciliation. The Diesel Reduction Strategy will also align with CleanBC and result in reduced overall GHG emissions. Details of the plan will be developed over the test period.

7.6 Thermal generation – We forecast a reduction in our emissions from our Thermal generation of 36 per cent by 2025 and continuing at or below that level to 2030

Thermal generation is a significant source of BC Hydro's emissions. Burrard Generating Station was decommissioned in 2010 leaving two thermal plants owned and operated by BC Hydro, Fort Nelson and Prince Rupert. Prince Rupert thermal Generating Station primarily serves a local load and as a back up for the system in the Northwest. Fort Nelson Thermal Generating Station is part of a separate grid tied to Alberta. While serving the local load, our thermal operations are also tied to trade.

We modelled the effect on our Fort Nelson operations from the escalating Federal carbon tax which is set to increase \$15/tCO_2 each year to 2030. The current carbon tax of \$50/tCO_2 is already factored into our decisions to run Fort Nelson for trade purposes. Our modelling indicates the effect of the escalating carbon tax to be about an 8-10 per cent drop in our Fort Nelson emissions per year to 2026. Since the available model only has data to 2026, we chose to flat line the forecast out to 2030, but there is a possibility that we could see further decreases beyond 2026 as the federal carbon tax continues to rise. There are some limits to the modelling; for example, it does not have visibility into the Alberta market conditions for the same period. The intent of the Federal carbon tax is to apply a dis-incentive to non-clean energy sources and according to our modelling it is likely to have that effect on our decisions to operate our thermal for trade.

7.7 IPPs – Our GHG forecast assumes that Electricity Purchase Agreements with two high emitting IPPs will not be renewed when they expire resulting in a significant reduction in emissions from our portfolio

IPPs are considered part of our Indirect Emissions and represent the largest source of emissions in our GHG portfolio. Although we do not own or operate these facilities, we may influence their operations through our decisions related to their EPAs with BC Hydro. Island Generation and McMahon are gas-fired IPP facilities and are the two largest sources of GHG emissions within our integrated system. Although the amount of the emissions will vary significantly from year to year, as a result of Island Generation operating as a dispatchable facility, these two facilities have accounted for up to two-thirds of our total annual GHG emissions.

The EPA with Island Generation expires in fiscal 2023 and the EPA with McMahon expires in fiscal 2030. Not renewing the Island Generation and McMahon EPAs could reduce annual system emissions by roughly 10,000 tonnes of CO_2e and 340,000 tonnes of CO_2e, respectively. BC Hydro's Draft 2021 IRP proposed that these EPAs will not be renewed. The final 2021 IRP will be filed with the British Columbia Utilities Commission in December 2021.

8 Investment in GHG reductions will be made through our existing budgets and prioritization processes

Our base capital budgets include some measures to reduce GHGs in the areas of buildings, fleet and NIAs. We are planning additional capital investment to achieve the forecast reduction in GHGs. In the short-term these investments will be managed opportunistically and treated as ex-plan through our prioritization process and/or funded out of existing budgets. Additional work will occur to advance specific capital investments that will be included in future capital plan updates.

9 We will Adapt our GHG Management Plan as Policy, Direction, and Markets Evolve

Government policy, GHG reduction technologies and market availability and cost of alternatives are areas of dynamic development. We propose a full review of the GHG Management Plan in 2025 which will align with the first targeted milestone in CleanBC and our next revenue requirements application, but interim decisions made by us or by others may require plan adjustments, including:

- Government policy and direction continues to develop, specifically the Comprehensive Review includes consideration of Internal Carbon Costing. If adopted this may affect our plan wherever we are making investment or operational decisions that include an element of GHG. We have not included the application of an Internal Carbon Cost in our forecast;

- The incremental cost and GHG reduction targets related to the NIAs renewable generation plan will be updated once the NIA strategy is fully developed; and
- Reductions in our fleet are dependent on market availability of suitable medium and heavy-duty EVs. If the market develops either faster or slower than we have predicted, we will adjust our plan.

Implementation of our GHG Management Plan is tied to the work we establish in our capital plans and operating budgets. Progress on our committed GHG reduction actions will be monitored quarterly and reported to our Executive Team annually. Our GHG Management Plan aligns with the objectives in the provincial government's CleanBC plan and as a key part of our Climate Change portfolio, it supports our organization in making real and significant GHG emission reductions.

BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

Appendix CC

Load Forecast Price Elasticity Report

Two Issues in the Use of Price Elasticities of Electricity Consumption

DIFFERENCES IN ESTIMATES DUE TO REAL VS NOMINAL PRICES AND PRICE INCREASES VS DECREASES

PREPARED BY

Ahmad Faruqui, Ph. D.
Goksin Kavlak, Ph. D.

PREPARED FOR

BC Hydro

AUGUST 16, 2021

Brattle

I. Executive Summary

The Brattle Group was retained by BC Hydro to review two issues related to the estimation of price elasticities. These issues had been raised by the BCUC in a recent order. One of the issues dealt with the differences that might arise in load forecasts if models were estimated with nominal prices versus real prices. The other issue dealt with differences that might arise in load forecast models if price elasticities were allowed to differ between price increases and price decreases.

Brattle economists have been working on the estimation of price elasticities for more than four decades. Dr. Faruqui, who was assisted by Dr. Kavlak, in this review has developed and reviewed demand forecasting models for utilities and regulatory agencies in North America, Asia, Australia and New Zealand.[1]

In the review, we relied on our expert opinion on the estimation of price elasticities, conversations with a few leading utilities, and a literature review. We came to the following conclusions:

- BC Hydro's approach to using price elasticities is broadly consistent with that taken by the surveyed utilities
- We do not think that replacing real prices with nominal prices would make much of a difference in the load forecast during the short and medium terms
- Utilities do not use nominal prices to estimate price elasticities
- Utilities do not differentiate between price elasticities for price increases and decreases
- We do not think it's an easy task to estimate price elasticities that differ between price increases and price decreases
- We were unable to find studies relating to electricity demand that address the two issues raised by the BCUC
- Available studies based on other commodities or products (i.e. non-utility) provide conflicting results - the studies show that there are reasons for asymmetries in demand response to price changes, as well as using real prices versus nominal prices. The conclusions are highly context-dependent and nuanced
- In summary, real prices and the symmetry assumption have been the standard practice for estimating price elasticities in load forecasting models

[1] Dr. Faruqui holds a doctorate in economics from the University of California at Davis. His dissertation was focused on estimating price elasticities for industrial customers in California. He has worked at the California Energy Commission, a state agency, and the Electric Power Research Institute on demand forecasting issues, in addition to working at consulting firms. He has been at Brattle since July 2006. Dr. Kavlak holds a doctorate from the Massachusetts Institute of Technology and was a post-doctoral associate there for three years before joining Brattle. Their biographical details can be found in Appendix A and at www.brattle.com. The Brattle Group is an economic consulting firm. In its electricity practice, Brattle assists electric utilities, deregulated power producers, customers, regulators, and policymakers with planning, ratemaking and litigation support, and with developing (or responding to) new market designs and regulatory frameworks.

II. Introduction

Background

The price elasticity of electricity consumption measures the percentage change in consumption that would occur in response to a one percent change in price. Electricity consumption, measured in kilowatt hours (kWh), is sometimes referred to as demand in the economist's sense of the term. It should not be confused with demand in the engineering sense of the term which is measured in kilowatts (kW).

BC Hydro uses the price elasticity of demand in its load forecast to estimate the changes in electricity consumption that would occur in response to changes in electric rates. A British Columbia Utilities Commission (BCUC) Panel previously reviewed BC Hydro's request to adjust the elasticity assumption from -0.05 to -0.1 and found that the proposed elasticity value was supported by the empirical literature on the subject. It was consistent with what was being used by other utilities. Therefore, the Panel found the elasticity assumption of -0.1 reasonable for the purpose of setting rates within the RRA across all customer sectors. BC Hydro also presented information that changing the price elasticity assumption had a minimal impact on the overall load forecast. BC Hydro showed that the load forecast was very similar under various elasticity assumptions (-0.05, -0.1 and -0.15).

However, the Panel noted customers may respond differently to nominal versus real changes in price. In addition, the Panel also noted that considering BC Hydro had requested a price decrease in fiscal 2021, customers' responsiveness to a price increase versus a price decrease may also differ. As a result, the BCUC requested BC Hydro to provide in the Fiscal 2023- Fiscal 2025 Revenue Requirements Application an analysis of:

- Any difference in elasticity between nominal versus real changes in price in the short-term and
- Any difference in elasticity between a price increase versus a price decrease.

Approach

This memorandum addresses this request in three separate ways: a utility survey, an illustrative numerical analysis, and a literature review. Section II presents a survey of North American utilities to determine current practices in the estimation and use of short-run price elasticities of electricity consumption to see if (a) price elasticities differed between nominal prices and real price and (b) price elasticities were allowed to differ between price increases and price decreases. Section III illustrates the effects of considering real versus nominal prices with a numerical example. Section IV presents a literature review on differences in price elasticity estimates when using nominal versus real prices as well as differences due to a price increase versus a price decrease. Section V summarizes the conclusions of the memorandum.

III. Utility Survey

We reached out to several North American utilities to determine the state of practice in the estimation of short-run price elasticities in electricity demand. Seven utilities responded to our request. In summary, here is what they said.

The surveyed utilities follow a common approach when estimating price elasticities. First, they use real prices in estimating price elasticities. Real prices are nominal prices deflated by a consumer price index to net out the effects of inflation. Survey respondents agreed that in theory the elasticity values might differ if nominal prices were used in their calculation and inflation rates were high. However, they said consumers were likely to respond to changes in real prices rather than nominal prices. In addition, most utilities stated that they did not perform the elasticity estimation themselves; they rather adopted estimates from the literature.

Second, utilities use the same elasticity value for price increases and decreases. Survey responses revealed that most utilities recognized that the elasticities might differ for price increases and decreases. However, they think that using the same values is sufficient and adding asymmetrical values would complicate the models, especially given the small impact of price elasticity on short-run load forecasts.

Extracts from their individual responses are reproduced below.

UTILITY A

We use price elasticities based on real prices as inputs into our long-term end-use models. **We no longer use price as a driver in our short-term econometric models** (monthly usage models for the next 2 to 3 years). In the past, we included price in short-term energy models before my time here (because we're all economists) but it was a chore to make it fit and have the correct sign. **The hypothesis is that customers, particularly residential customers, are more informed about their bills and less informed about and responsive to price per kWh.** And, here in the South, their bills are a whole lot more sensitive to factors such as weather than any change in per unit price. In the longer term, however, both absolute and relative price could impact usage and choice of end-uses, so we do include price elasticities in our long-term end-use models.

To answer your second question, the same price elasticities apply to price increases and decreases. This is an interesting question. We have not conducted or came across any research on the topic.

UTILITY B

We use real price of electricity in our econometric models. This is based on the economic theory that consumers react to real price changes. Whether price elasticity would differ across real versus nominal prices depends on the situation with inflation. During periods of high inflation, the two could differ significantly.

We do not model asymmetric reactions to price increases versus price decreases. **Since price elasticities for most types of consumers are rather small, it's counterproductive to complicate the models, especially in regulatory settings**.

UTILITY C

We don't actively estimate price elasticity. We have a set value of -0.15 that we have used for years. It is a high-level estimate based on older research papers for North American utilities, so not specific to our region. In our SAE model we apply the elasticity to real prices in a "heat use" variable that also incorporates projected HDD and household size, so elasticity has only a modest impact on the overall forecast.

In terms of increases vs decreases, no we don't differentiate. I'm not sure about asymmetry in the elasticity, it's an interesting question and it seems like there are equal opportunities for substitution for both increases (solar) and decreases (EV's and electric heat), but I can see a case where the impact of substitution within various customer segments could be asymmetrical.

We get questions about our elasticity estimate every year when we file our forecast, but have **never had questions about real vs nominal. We've never gotten around to estimating elasticity, it's on our list of "things to do when we have time", and the current estimate seems to be in the ballpark. It's low on the list as I think the exercise will only give us a rough idea anyway,** there are many subgroups within the different classes that will all have distinct elasticities, and as you say we haven't seen any big swings in price so sales variation will be influenced by many other factors. To date nobody has really pushed us on updating our values, and **there are much bigger unknowns on the end-use side of the forecast that are higher priorities for us.**

For our SAE[2] model, we use the U.S. Energy Information Administration (EIA) efficiency data for our region and shares for some of our end use forecasts, and internal estimates for some of the key uses like electric space heating and hot water. We conducted an end use survey in 2019 which we use for our historic shares, and we also have National Resources Canada data but it runs 3 year behind and some of the metrics (particularly space heating) are way off from our internal data so we've been getting away from that.

UTILITY D

If I read your question accurately, it relates to forecasted load information and incorporating into our growth forecast where customer behaviors, emerging technologies or EE, electrification through EV's, etc. all impact price elasticity and how they are factored into that forecast.

From a rate design and cost allocation perspective, we are obligated to use a historical Test Year for ratemaking purposes in our jurisdiction, so we pull actual customer usage during the Test Year and apply adjustments to normalize weather and to annualize the customer count. We generally do not apply adjustments for price elasticity, although in 2017 we did implement rates with an assumption that customer who would save more than 10% would change rates to their most economical rate plan. As you know, we have found that forecast was quite accurate. I know some utilities apply adjustments to their proof of revenue billing determinants or income statement adjustments to their cost of service study to account for customer usage

[2] Statistically adjusted econometric models are called SAE models in the literature

changes or lost revenue associated with changes in behaviors which are likely produced through elasticity studies. As of yet, we have not adopted these into our processes or filings, although we do produce workpapers that show the effects of customer response to our time of use hours. In our most recent case, I included some charts with my rebuttal testimony that show customer response to the on peak hours at 3:00 PM and again at 8:00 PM where consumption drops dramatically at 3:00 and resumes at 8:00 as they respond to our on-peak price signals.

Paraphrased response from another employee from the same utility:

We use real prices because we think customers respond to real prices. In theory, there may be a difference between how they respond to real versus nominal prices but we don't think it matters in practices. It would make a difference if inflation rates were high.

We also don't differentiate between price increases versus price decreases when estimating price elasticities.

UTILITY E

We use real prices in a couple of our residential sales models. Real prices are used to account for the impacts of inflation. **We do expect that elasticities would differ if nominal prices were used instead, as the nominal elasticities would be accounting for both the inflation in the price of electricity as well as the price elasticity of consumption.**

Intuitively we think the elasticities likely would differ for increasing versus decreasing prices. However, we use regression models of monthly sales which provide the average response to price changes during the sample period and we assume that is a sufficient proxy for either increasing or decreasing prices.

UTILITY F

1. We use real pricing. The choice to use real was made before my time, but I think the reasoning was simply to allow the model to see the true growth in pricing over time**. Yes, I**

think there would be some difference in elasticities across real vs nominal, but how significant is hard to say.

2. **We do not differentiate between price increases and decreases, either. A single real price variable has been sufficient for our purposes in capturing the pricing element on load and I'm not sure that splitting it into increase versus decrease would add any more precision.**

UTILITY G

We use real prices in our SAE model. From our experience nominal price tends to exaggerate usage growth.

We don't differentiate between price increases or price decreases when estimating price elasticities. We use a SAE model now to be consistent with other utilities for benchmarking and interpretation purpose. **Another reason we didn't bother with it is that in the long run (year 7 and onward) we hold the real price constant voiding price effect all together.**

IV. Illustrative Regression Analysis

The main goal of this analysis is to show how price elasticity values may differ when real versus nominal prices are used in the estimation process. Here we illustrate this with a hypothetical example by employing a simplified version of the statistical models used to estimate price elasticity of demand.

Price elasticity of demand is estimated by regression analysis, where the dependent variable is 'demand' and independent variables are a set of covariates (e.g. energy prices, population, income, climate) as well as the lagged values of the covariates and the dependent variable. A logarithmic transformation of both the dependent and independent variables in a linear regression model is used to estimate the regression coefficients. With this model, the regression coefficient of an independent variable such as energy price is referred to as 'price elasticity' and interpreted as the percentage change in demand in response to one per cent change in price.

In this example, we set up a multiple regression including two independent variables, electricity price and income per capita. The dependent variable is electricity demand per capita. The regression equation is the following:

$$\log(\text{Demand}) = \alpha + \beta\log(\text{Price}) + \gamma\log(\text{Income per capita}) + \varepsilon$$

The data used for this regression is shown in Table 1. For illustrative purposes, we use hypothetical electricity demand values for a residential customer starting 10,000 kWh per capita in 2000 and decreasing at a rate of -0.4% per year. For prices, we use the nominal average US residential electricity prices during the past two decades.[3] We then obtain the real prices by deflating the nominal prices using the US GDP deflator.[4] We also use the real average the income per capita in the US.[5]

[3] U.S. Energy Information Administration Average Retail Price of Electricity to Ultimate Customers, Residential. https://www.eia.gov/electricity/monthly/

[4] U.S. Bureau of Economic Analysis, Gross Domestic Product: Implicit Price Deflator [GDPDEF], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/GDPDEF, July 3, 2021.

[5] U.S. Bureau of Economic Analysis, Real gross domestic product per capita [A939RX0Q048SBEA], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/A939RX0Q048SBEA, July 14, 2021.

TABLE 1: DATA USED FOR ILLUSTRATIVE REGRESSION MODEL

Year	Demand (kWh)	Nominal price (cents/kWh)	Real price (cents/kWh) (2019$)	Real per capita income (2019$)
2000	10,000	8.24	11.84	52,199.16
2001	9,960	8.58	12.08	52,198.88
2002	9,920	8.45	11.70	52,604.15
2003	9,880	8.72	11.86	53,610.59
2004	9,841	8.95	11.85	55,147.47
2005	9,802	9.43	12.11	56,558.89
2006	9,762	10.40	12.97	57,623.99
2007	9,723	10.65	12.93	58,144.89
2008	9,684	11.26	13.41	57,524.91
2009	9,646	11.51	13.60	55,571.26
2010	9,607	11.54	13.48	56,529.42
2011	9,569	11.72	13.41	56,995.31
2012	9,530	11.88	13.34	57,869.28
2013	9,492	12.13	13.38	58,535.28
2014	9,454	12.52	13.56	59,584.66
2015	9,417	12.65	13.58	60,980.65
2016	9,379	12.55	13.33	61,588.83
2017	9,341	12.89	13.43	62,631.19
2018	9,304	12.87	13.10	64,166.67
2019	9,267	13.01	13.01	65,238.78
2020	9,230	13.20	13.04	62,654.21

The regression results show that price elasticity estimates differ when real prices versus nominal prices are used (Table 2). The price elasticity (coefficient of price) with real prices is -0.362 and with nominal prices is -0.308. Note that this example does not indicate that nominal prices would always result in higher or lower elasticities; this example is only intended to show that the elasticities would *differ* when the underlying data changes. Also, note that the coefficient of the income variable (income elasticity of demand) changes as well.

TABLE 2: REGRESSION RESULTS FOR NOMINAL VERSUS REAL PRICES

Nominal Price	log(income)	log(NP) Price Elasticity	Intercept
Coefficient	-0.215	**-0.308**	12.198
Std error	0.130	0.051	1.322
R squared	0.922		
F-statistics	111.519		
Regression Sum of Squares	0.082		
Standard error for Y estimate	0.019		
Degree of freedom	19		
Residual sum of squares	0.007		
t-statistics	-1.650	-6.017	9.228
P-value	0.115	0.000	0.000
Significance		***	***

Real Price	log(income)	log(RP) Price Elasticity	Intercept
Coefficient	-0.700	**-0.362**	17.704
Std error	0.128	0.155	1.188
R squared	0.823		
F-statistics	44.144		
Regression Sum of Squares	0.074		
Standard error for Y estimate	0.029		
Degree of freedom	19		
Residual sum of squares	0.016		
t-statistics	-5.470	-2.339	14.906
P-value	0.000	0.030	0.000
Significance	***	**	***

V. Literature Review

This section presents a review of the academic literature on differences in price elasticity estimates when using nominal versus real prices as well as differences due to a price increase versus a price decrease.

In summary, many academic references show that price elasticity estimation is mostly carried out with real prices. This confirms the utilities' current practice of using price elasticities based on real, inflation-adjusted prices. However, there is a body of behavioral economics literature which states that consumers tend to think in think of money in nominal rather than real terms. This implies that the effects of inflation and price changes might be conflated in determining consumers' behavior.

Secondly, there has been an ongoing debate in the energy economics literature on the subject of "asymmetry" in price elasticities due to price increases versus decreases. Empirical findings on asymmetric response to prices has theoretical foundations in behavioral economics, namely the "loss aversion" concept. The concept of loss aversion suggests that people perceive losses (e.g. price increases) more severely. While several studies found asymmetries with empirical analyses, other studies rebut this finding arguing that the asymmetry is only an artifact of modeling choices. There is also ongoing research in other fields, notably transportation and retail marketing, on the asymmetric demand response to price changes. Retail marketing empirical studies found asymmetries; however, the direction of asymmetry differed among studies. While a group of studies indicated that demand is more responsive to price increases, others found the opposite.

A more detailed summary of relevant academic references is provided below for each question.

References regarding question (i) any difference in elasticity between nominal versus real changes in price in the short-term

Several studies show that estimation of price elasticity is usually performed in real terms, in other words, by using inflation-adjusted values.[6,7,8,9,10] However, behavioral economics literature claims that people tend to make decisions based on nominal prices rather than real

[6] Bernstein, M. A., & Griffin, J. (2006). Regional Differences in the Price-Elasticity of Demand for Energy. National Renewable Energy Lab (NREL), https://www.osti.gov/biblio/877655.

[7] Ros, A.J. (2020). Does electricity competition work for residential consumers? Evidence from demand models for default and competitive residential electricity services. Journal of Regulatory Economics, 58(1), 1-32.

[8] Deryugina, T., Mackay, A., & Reif, J. (2020). The long-run elasticity of electricity demand: Evidence from municipal electric aggregation. American Economic Journal: Applied Economics, 12(1), 86–114.

[9] Burke, P. J., & Abayasekara, A. (2018). The price elasticity of electricity demand in the United States: A three-dimensional analysis. The Energy Journal, 39(2).

[10] Dergiades, T., & Tsoulfidis, L. (2008). Estimating residential demand for electricity in the United States, 1965–2006. Energy Economics, 30(5), 2722-2730.

prices. This concept is considered a cognitive bias and referred to as "price illusion" (or money illusion).[11] According to this literature,[12] consumers tend to perceive money in nominal terms because nominal prices are a more natural representation of an economic situation for most people and most economic transactions are framed in nominal terms. In its basic form, price illusion occurs when people take nominal values or changes in nominal values as a proxy for real values or changes in real values, respectively. Price illusion is not only experienced by laypeople; people who are expected to have a better understanding of economic concepts are shown to experience it, too. For example, a research paper[13] finds that investors suffer from price illusion and for this reason firms proactively manage share prices to stay in a relatively constant nominal range to cater to investor demand. The neurological evidence for price illusion has also been demonstrated through medical imaging: A study utilized fMRI (Functional magnetic resonance imaging) to investigate the brain's reward circuitry and found that areas of the brain associated with the processing of anticipatory and experienced rewards, and the valuation of goods, exhibited price illusion.[14] The literature on price illusion implies that energy consumption behavior might, in fact, be influenced by nominal rather than real prices. These findings have not been adopted by energy economics studies; and for the short run elasticity, the effect of real versus nominal prices may not be as important for energy. Because electricity demand is relatively inelastic in the short-run, small changes in price would lead to only small changes in demand therefore would not impact the demand forecast drastically.

References regarding question (ii) any difference in elasticity between a price increase versus a price decrease.

Differences in elasticity between a price increase versus a price decrease ("asymmetries" in price response) have been investigated in energy studies as well as in other fields. Here we summarize relevant articles from both energy and other literatures such as transportation and retail marketing research.

[11] Shafir, E., Diamond, P., & Tversky, A. (1997). Money illusion. The Quarterly Journal of Economics, 112(2), 341-374.

[12] Fehr, E., & Tyran, J. R. (2001). Does money illusion matter? American Economic Review, 91(5), 1239-1262.

[13] Birru, J., & Wang, B. (2016). Nominal price illusion. Journal of Financial Economics, 119(3), 578-598.

[14] Weber, B., Rangel, A., Wibral, M., & Falk, A. (2009). The medial prefrontal cortex exhibits money illusion. Proceedings of the National Academy of Sciences, 106(13), 5025-5028.

Empirical analyses of asymmetric price elasticities are often linked to theories in behavioral economics, prospect theory in particular.[15] Prospect theory postulates that customers are "loss averse" in prices; in other words, may perceive a price increase as a loss and respond more strongly to a price increase than they do to an equivalent price decrease. Price changes are evaluated relative to an endogenous reference price, which depends on the consumers' price expectations from the recent past. Demand responses are more elastic for price increases than for price decreases and thus firms face a downward-sloping demand curve that is kinked at the consumers' reference price.[16] Empirical evidence for loss aversion has been presented for a variety of products and services such as consumer goods,[17,18] energy use,[19] restaurant visits,[20] and transportation.[21]

In the energy economics literature, there is an ongoing debate on the topic of asymmetry in price elasticities due to price increases versus decreases. A widely-cited study by Gately and Huntington (2002)[19] finds that demand for oil in OECD countries responds much more to increases in oil prices than to decreases, indicating an asymmetry. According to this study, ignoring the asymmetry would have implications for the elasticity estimates and long-term forecast of energy demand. For example, wrongly assuming symmetry will bias downward the estimated income elasticity. In addition, the study also highlights that not only price elasticity but also income elasticity of demand is asymmetric and finds that demand for oil responds more to income increases than decreases. However, this study's focus is on estimating the long-run response of demand to price and income changes; the conclusions may not be as pronounced for the short-run elasticity.

Opposing views have been documented in other studies where researchers claimed that what has been attributed to asymmetry is an artifact of modeling choices. For example, Griffin and

[15] Kahneman, D., & Tversky, A. (2013). Prospect theory: An analysis of decision under risk. In Handbook of the fundamentals of financial decision making: Part I (pp. 99-127).

[16] Ahrens, S., Pirschel, I., & Snower, D. J. (2017). A theory of price adjustment under loss aversion. Journal of Economic Behavior & Organization, 134, 78-95.

[17] Kalyanaram, G., & Little, J. D. (1994). An empirical analysis of latitude of price acceptance in consumer package goods. Journal of consumer research, 21(3), 408-418.

[18] Dossche, M., Heylen, F., & Van den Poel, D. (2010). The kinked demand curve and price rigidity: Evidence from scanner data. Scandinavian Journal of Economics, 112(4), 723-752.

[19] Gately, D., & Huntington, H. G. (2002). The asymmetric effects of changes in price and income on energy and oil demand. The Energy Journal, 23(1).

[20] Morgan, A. (2008). Loss aversion and a kinked demand curve: Evidence from contingent behaviour analysis of seafood consumers. Applied Economics Letters, 15(8), 625-628.

[21] Yaman, F., & Offiaeli, K. Is the Price Elasticity of Demand Asymmetric? Evidence from Public Transport Demand.

Schulman (2005)[22] show that the hypothesis of symmetric price responses cannot be rejected after explicitly controlling for energy saving technical change within the statistical model. According to this study, the effect of energy saving technical change was wrongly attributed to price asymmetry.

Transportation has been an active area of research on the relationship between demand and prices. Yaman and Offiaeli (2017)[21] analyze the price elasticity of demand for public transportation, the London Underground, during a period of time when some of the fares on the network have increased while others have decreased, offering a unique opportunity to observe price elasticities for both cases. The study finds that demand is more sensitive to price increases than to decreases. Other articles study demand for transportation fuels and find statistical evidence for gasoline price and income both can induce asymmetric changes in gasoline demand. For example, Wadud (2017)[23] finds that elasticity with respect to rising prices and falling income is larger than the elasticity with respect to falling prices and rising income respectively, which is consistent with loss aversion in gasoline purchase behavior.

Price elasticity asymmetries have been widely studied by retail marketing research. While a group of empirical studies finds evidence of higher price sensitivity for price increases in line with loss aversion theory, others report opposite results. For instance, Dossche et al.[18] uses data from a large Euro area supermarket chain containing information about prices and quantities sold of about 15,000 items from 2002 through 2005. Consistent with loss aversion, the study finds that the overall price elasticity of demand is higher for price increases than for price decreases. Kalyanaram and Winer (1995)[24] cite several other empirical studies that arrived at the same conclusion and reports asymmetric, heightened responsiveness to price increases as a generalizable observation across retail marketing.

[22] Griffin, J. M., & Schulman, C. T. (2005). Price asymmetry in energy demand models: a proxy for energy-saving technical change? The Energy Journal, 26(2).

[23] Wadud, Z. (2017). Asymmetry in transport fuel demand: Evidence from household level data. Transportation Research Part D: Transport and Environment, 57, 277-286.

[24] Kalyanaram, G., & Winer, R. S. (1995). Empirical generalizations from reference price research. Marketing science, 14(3_supplement), G161-G169.

On the other hand, several other retail marketing studies find that demand is more sensitive to price decreases than to price increases.[25,26,27,28] The effect of promotions is considered a possible explanation for this phenomenon. Especially in the case of a product with infrequent promotions, customers often respond to a price decrease by stockpiling. Promotions induce the feeling of large gains by outweighing the loss they create in future periods.[26] For instance, Pauwels et al. (2007)[27] finds increased price sensitivity for price decreases because consumers wait for deals. Importantly, this study also notes that before consumers can respond to a price change and contrast the new price with their benchmark, the new price must be perceived as different. A loss must also exceed a certain threshold in order to be perceived, therefore minor price hikes within the threshold are less likely to be noticed. Krishnamurty et al. (1992)[28] contributes to this literature by highlighting the effect of heterogeneity among customers on price elasticity. Loyal customers do not exhibit asymmetric response, while "switchers" might be more sensitive to price increases. Note that these conclusions are derived in the context of retail consumer goods, where switching between substitutes is possible; however, these nuances may not apply directly to energy consumption behavior due to lack of readily available substitutes. Nevertheless, there is an indication of heterogeneous price elasticities for different income groups or countries (e.g. OECD countries vs non-OECD countries) in energy consumption as well.[19]

VI. Conclusion

This memorandum presents a survey of North American utilities to identify current practices in the use and estimation of short-run price elasticities of electricity consumption and to present a review of the academic literature on the topic.

In practice, utilities use real prices and the symmetry assumption in load forecasting. Responses to the utility survey indicate that this practice is sufficient for utilities and adding complexity in the use and estimation of price elasticities would not add value to the load forecast, especially

---

[25] Bonnet, C., & Villas-Boas, S. B. (2016). An analysis of asymmetric consumer price responses and asymmetric cost pass-through in the French coffee market. European Review of Agricultural Economics, 43(5), 781-804.

[26] Greenleaf, E. A. (1995). The impact of reference price effects on the profitability of price promotions. Marketing science, 14(1), 82-104.

[27] Pauwels, K., Srinivasan, S., & Franses, P. H. (2007). When do price thresholds matter in retail categories? Marketing Science, 26(1), 83-100.

[28] Krishnamurthi, L., Mazumdar, T., & Raj, S. P. (1992). Asymmetric response to price in consumer brand choice and purchase quantity decisions. Journal of consumer research, 19(3), 387-400.

for the short-run forecast due to the small effect of price elasticity on the load forecast, and may in fact hinder the regulatory process.

In the academic literature, there is ongoing debate on the estimation of price elasticities in different research fields including energy economics, behavioral economics, and marketing. The academic literature presents both theories and empirical evidence concerning the two questions asked by the BCUC Panel.

In summary, there are arguments for and against the existence of asymmetries in demand response to price changes, as well as using real prices versus nominal prices. The conclusions are highly context-dependent and nuanced.

Appendix A: Author Biographies

Dr. Ahmad Faruqui is an internationally recognized authority on the design, evaluation and benchmarking of tariffs. He has analyzed the efficacy of tariffs featuring fixed charges, demand charges, time-varying rates, inclining block structures, and guaranteed bills. He has also designed experiments to model the impact of these tariffs and organized focus groups to study customer acceptance. Besides tariffs, his areas of expertise include demand response, energy efficiency, distributed energy resources, advanced metering infrastructure, plug-in electric vehicles, energy storage, inter-fuel substitution, combined heat and power, microgrids, and demand forecasting. He has worked for nearly 150 clients on 5 continents, including electric and gas utilities, state and federal commissions, governments, independent system operators, trade associations, research institutes, and manufacturers.

Ahmad has testified or appeared before commissions in Alberta (Canada), Arizona, Arkansas, California, Colorado, Connecticut, Delaware, the District of Columbia, FERC, Illinois, Indiana, Kansas, Maryland, Minnesota, Nevada, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, Saudi Arabia, and Texas. He has presented to governments in Australia, Egypt, Ireland, the Philippines, Thailand, New Zealand and the United Kingdom and given seminars on all 6 continents. He has also given lectures at Carnegie Mellon University, Harvard, Northwestern, Stanford, University of California at Berkeley, and University of California at Davis and taught economics at San Jose State, the University of California at Davis, and the University of Karachi.

His research been cited in Business Week, The Economist, Forbes, National Geographic, The New York Times, San Francisco Chronicle, San Jose Mercury News, Wall Street Journal and USA Today. He has appeared on Fox Business News, National Public Radio and Voice of America. He is the author, co-author or editor of 4 books and more than 150 articles, papers and reports on energy matters. He has published in peer-reviewed journals such as Energy Economics, Energy Journal, Energy Efficiency, Energy Policy, Journal of Regulatory Economics and Utilities Policy and trade journals such as The Electricity Journal and the Public Utilities Fortnightly. He is a member of the editorial board of The Electricity Journal. He holds BA and MA degrees from the University of Karachi, both with the highest honors, and an MA in agricultural economics and a PhD in economics from The University of California at Davis, where he was a research fellow.

Dr. Goksin Kavlak is an Associate in The Brattle Group's Boston, MA office. She has extensive experience in modeling the economic implications of alternative energy technology deployment. She has developed methods to evaluate the drivers of technological change in energy systems and authored several high-impact academic articles and reports in this area. Goksin's research has been featured in news outlets such as the New York Times and Financial Times. Goksin's more recent projects include analyzing the electrification potential of buildings and transportation in states with decarbonization goals, rate design for electric vehicle charging, and budget implications of rate increases.

Prior to joining Brattle, Goksin worked at the Massachusetts Institute of Technology as a Postdoctoral Associate, where she led a project team investigating photovoltaics system cost reduction in response to engineering innovations and policies. Goksin earned her Ph.D. degree in Engineering Systems from the Massachusetts Institute of Technology, her M.E.Sc. degree in Environmental Science from Yale University, and her B.S. degree in Industrial Engineering from Bogazici University.

BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

Appendix DD

BC Hydro's Monthly Energy Studies

Table of Contents

List of Figures

List of Tables

1 Introduction

This appendix describes the components and processes that comprise the Monthly Energy Studies, along with the key inputs and outputs of the Monthly Energy Studies.

The Monthly Energy Studies optimize the operational management of generation within BC Hydro's integrated system over the operating time horizon.[1] The Monthly Energy Studies inform operational dispatch decisions and forecast the Cost of Energy for financial reporting purposes. The studies consider a wide range of factors including wholesale electricity trade opportunities, which are necessary and valuable to manage energy deficits and surpluses and increase overall benefits for ratepayers in a hydroelectric system.

BC Hydro's Monthly Energy Studies methodology has not changed from the methodology used in the prior two revenue requirements applications. BC Hydro's objective function in the Energy Studies is to maximize the expected Consolidated Net Revenue from Operations (**CNRO**), which is discussed further in section 1.4 below. BC Hydro is continually improving its modelling capability and the development plan for the models is discussed in section 3 below. The models used in the Monthly Energy Studies are validated and updated on an ongoing basis.

1.1 Monthly Energy Studies Background

The primary objective of a Monthly Energy Study is to forecast, over the operating time horizon, an optimal set of reservoirs and generating station operations and system imports and exports under current forecasts of loads, market prices, inflows, generation unit availability and operational constraints. This modelling also provides:

[1] The operating time horizon is the balance of the current fiscal year plus the next two fiscal years. An additional two years are modeled so that the forecast for the first three years accounts for the impact of any longer-term operational constraints.

- The marginal value of water in BC Hydro's two largest reservoirs (Williston and Kinbasket) that is used to inform operational dispatch decisions; and
- The Cost of Energy for financial reporting.

The Monthly Energy Studies model the use of large storage reservoirs that are used to help manage variability in the annual water supply. They evaluate the wide range of possible inflow scenarios that may occur and consider other relevant factors including uncertainty in domestic load, outages, constraints such as reservoir limits, and market prices. It is important to recognize that while the Monthly Energy Studies and other quantitative tools provide important insights to help guide BC Hydro's decision-making related to the operation of the generating system, they are not the sole basis for those decisions. These decisions do not involve merely implementing the results produced by the Monthly Energy Studies or by any other single quantitative tool used by BC Hydro. Instead, they are reached through extensive discussions and deliberations that occur on an ongoing basis, informed by the model results.

Variation in precipitation and snowmelt results in a wide range of uncertainty in the amount and timing of BC Hydro system inflows: approximately +/- 7,000 GWh per year. Outside temperature and weather may also impact load by +/- 700 GWh per year.

The challenge is to make decisions in the present, given an uncertain future of possible outcomes. The Monthly Energy Studies, and the supporting models that produce the study results, support the decision-making by providing information on the range of possible outcomes from the use of BC Hydro's large reservoirs.

Key inputs of the Monthly Energy Studies are:

- Inflow Forecasts;
- Load Forecasts;

- Market Forward Prices;
- IPP Forecasts;
- Generation Unit Availability Forecasts; and
- Operational Constraints.

These inputs are discussed further in section 2.2 below.

Key outputs of the Monthly Energy Studies are:

- Forecasts of the operation of the generating system and major storage reservoirs;
- Forecasts of price signals to be used as decision support for system hydro and thermal plant operations relative to markets; and
- Forecasts of imports and exports.

1.2 Monthly Energy Studies Models Oversight and Controls

The Energy Studies are produced every month. The results are reviewed weekly by the Generation System Operations (**GSO**) Key Business Unit, discussed with Powerex, compared to other models, and tracked against actuals. The results are reviewed every month by the Executive Vice President of Operations.

BC Hydro maintains the integrity of the Monthly Energy Studies process using a proprietary tool, the Energy Studies Manager. The Energy Studies Manager helps to manage process flow and the thousands of datasets that make up model inputs, outputs and parameters. Each month the progress of the Monthly Energy Study is tracked through the Energy Studies Manager as team members update input data and run models. This tool also archives all the relevant historic and forecast data at each step in the process.

The models, underlying code and documentation are managed using an industry-standard software versioning and revision control system, enabling team members to collaboratively work to improve models, and if necessary, restore historical versions.

All data files are stored in a standard format which is easily manipulated using in-house software libraries and can be quickly inspected using any text editor. Each data file contains its own metadata to define such things as the model or external source that produced the data, the user who ran the model, the date/time stamp when it was run, and units of measurements, and this provides an additional auditing mechanism.

1.3 Energy Studies Modelling Approach

BC Hydro's Monthly Energy Studies consists of i) a data management platform that links data inputs and outputs, and ii) a suite of models. The data management platform and Energy Studies models are developed and maintained by the GSO Key Business Unit within the Operations Business Group.

Five primary characteristics are considered in developing and maintaining these models:

1. **Account for uncertainty:** Modelling BC Hydro's generating system and its interactions with external markets involves incorporating the significant uncertainties in forecast inflows, electricity and gas prices, loads, and operational constraints. These sources of uncertainty are addressed in the Monthly Energy Studies by using modelling techniques that are tailored to explicitly represent these uncertainties in the optimization process and produce a distribution of outcomes in the form of an ensemble forecast;
2. **Optimize the most flexible resources:** The Monthly Energy Studies process seeks to optimize the overall system by focusing on the operation of the largest,

most flexible resources that have the greatest ability to respond to changes in inflows, load, and market prices. The process assumes the smaller plants and less flexible resources are generally operated as they have been previously under equivalent historic inflow conditions;

3. **Maximize Consolidated Net Revenue from Operations (CNRO):** This objective function is described further in section 1.4 below;

4. **Use reservoir marginal values (price signals):** While the system operations are driven largely by inflows and loads, operations at the large storage reservoirs on the Peace and Columbia are also guided by price signals which provide decision support for dispatch of hydro and thermal resources relative to import and export opportunities; and

5. **Produce risk neutral forecasts:** The optimization procedure assumes each of the modeled possible outcomes is equally likely and the mean forecast of these outcomes provides the best operating strategy. In other words, a risk neutral operating strategy is based on an expected outcome and does not bias towards or against favorable or unfavorable outcomes. The models serve load and manage inflows under all these modeled potential scenarios.

As of January 2021, historic weather, inflow, and generation data exists for the period 1972 through 2020. These 49 years provide the basis for the ensemble (a collection or set used to forecast the range of uncertainty. This same set of 49 weather year ensembles is used throughout the Energy Studies process. The use of the same set of historic ensembles ensures that variability in inflows, prices, loads, and resources due to the impacts of weather are well represented in the models.

The variability in the historic record is an order of magnitude larger than the impact of any climate change on the mean forecast over the time horizon of an Energy Study. Nonetheless, since the ensembles always contain the most recent historic observations, effects of climate change are implicitly included to the extent that climate change has influenced observed data.

1.4 System Optimization Objective

The approach to operational decisions to optimize the use of BC Hydro's large reservoirs has served ratepayers well. Further information about BC Hydro's system optimization objective was provided in BC Hydro's compliance filing on the F2020-F2021 RRA to the BCUC dated December 1, 2020.[2]

BC Hydro's system optimization objective is to maximize "expected consolidated net revenue from operations" (**CNRO**). The term CNRO contains three distinct terms: "consolidated", "net revenue" and "from operations". These terms reflect the scope of system optimization rather than how the system is optimized. Specifically:

- **Consolidated** means the consolidated activities related to imports and exports from the BC Hydro system. This includes both imports required to serve load and exports to manage surpluses as well as estimates of imports and offsetting exports by Powerex for trade activities. It does not include Powerex activity that is unrelated to the BC Hydro system;
- **Net Revenue** means the sum of cost and revenue items that are related to operation of the generation system. BC Hydro uses the term net revenue instead of net income because costs that are not related to system dispatch decisions (e.g., finance charges, taxes, depreciation) are excluded from CNRO; and
- **From Operations** refers to the dispatch of the generation system (i.e., deciding what generating units to run when) and the release of water from the facilities (i.e., discharges through turbines or spillways).

[2] Refer to: https://www.bcuc.com/Documents/Proceedings/2021/DOC_61069_2020-12-01-BCH-F2020-21RRA-Compliance-to-G-246-20-Directives-.pdf.

Expected is a statistical term that is short for the "expected value of a variable with a probability distribution".

In other words, the objective function of the Energy Studies models is to compute the CNRO for all potential outcomes in such a way that the average value is maximized. This is also referred to as "risk neutral". Risk neutral is an important economic concept and refers to an approach that is neither risk averse nor risk seeking. It assumes each of the modeled possible outcomes is equally likely and is based on the expected outcome with no bias towards or against any particular outcome.

BC Hydro maximizes expected CNRO over the operating time horizon. This means that BC Hydro seeks to optimize value over time, using the flexibility of multi-year storage.

CNRO is calculated as follows:

- Domestic revenue from accrued sales;
- Plus revenue from System Exports;
- Plus net revenue from Columbia River Treaty related agreements;[3]
- Less cost of IPPs and Long-Term Commitments;
- Less cost of System Imports;
- Less cost of Water Rentals on Generation;[4] and
- Less cost of Natural Gas for Thermal Generation.

CNRO includes items that are impacted by system dispatch and water release decisions, which affect system storage. It also includes items affected by weather

3 Each year, this revenue can be negative or positive. Columbia River Treaty related agreements include the Non-Treaty Storage Agreement and Libby Coordination Agreements.

4 CNRO does not include the cost of water rentals on capacity.

because weather affects system storage and must be considered in system dispatch decisions.

The weather components of CNRO are uncontrollable. For example, domestic revenue is included in CNRO because weather affects load (e.g., customers use more electric heat when temperatures are colder, which increases demand). IPPs and Long-term Commitments are included because weather affects the amount of hydroelectric or wind energy that is generated from these facilities, which BC Hydro is required to take.

While these components are included as part of the CNRO calculation, the Energy Studies only inform decisions regarding the cost of dispatchable energy components.

2 Monthly Energy Studies Description

2.1 Overview of Process

During each study, input forecasts for inflows, loads, forward market prices, IPPs, generation unit availability and operational constraints are collected, and these provide inputs to models that represent the components of the generating system. These in turn feed models that optimize the system to maximize operations-related revenue. Finally, an accounting model implements the 2020 TPA pricing for system imports and exports and necessary reports are produced.

The models, at a minimum, are at a monthly time step; however, many model components execute with a finer granularity (as short as eight hours).

Figure DD-1 below provides an overview of the model inputs and components involved in the Monthly Energy Study process. Figure DD-2 below presents a high-level view of the sequence of operations involved in a Monthly Energy Study.

Figure DD-1 Overview of the Energy Studies Process

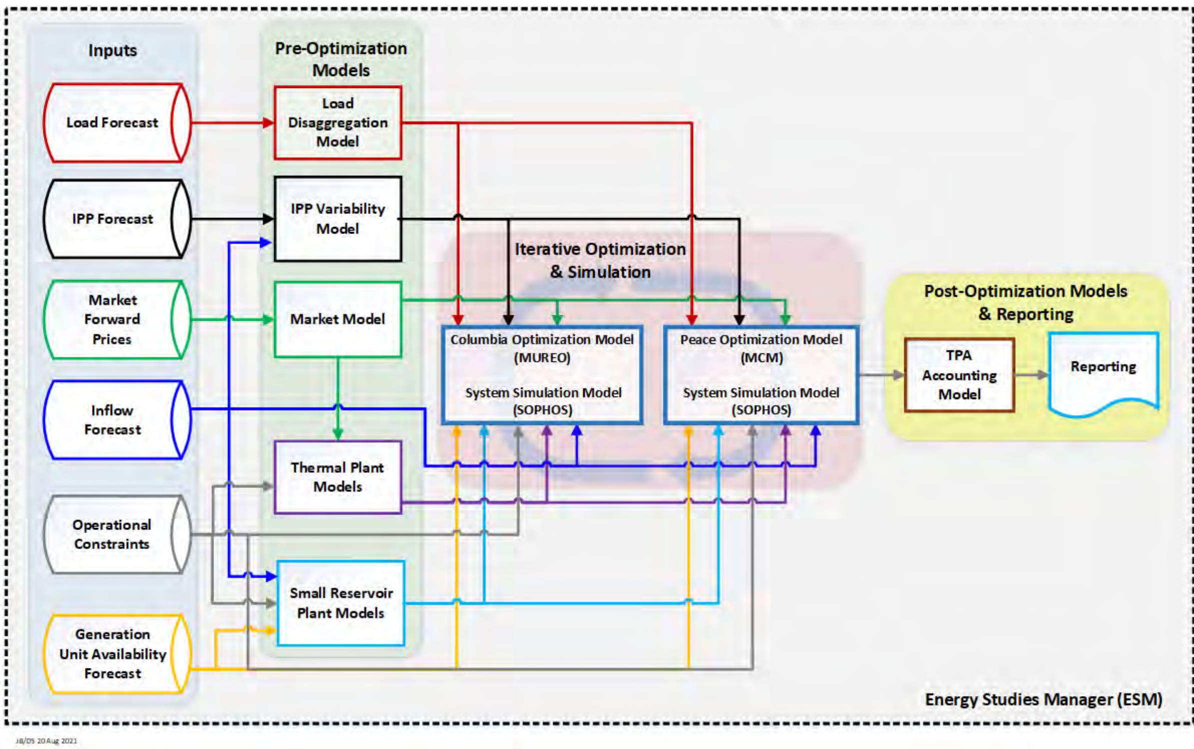
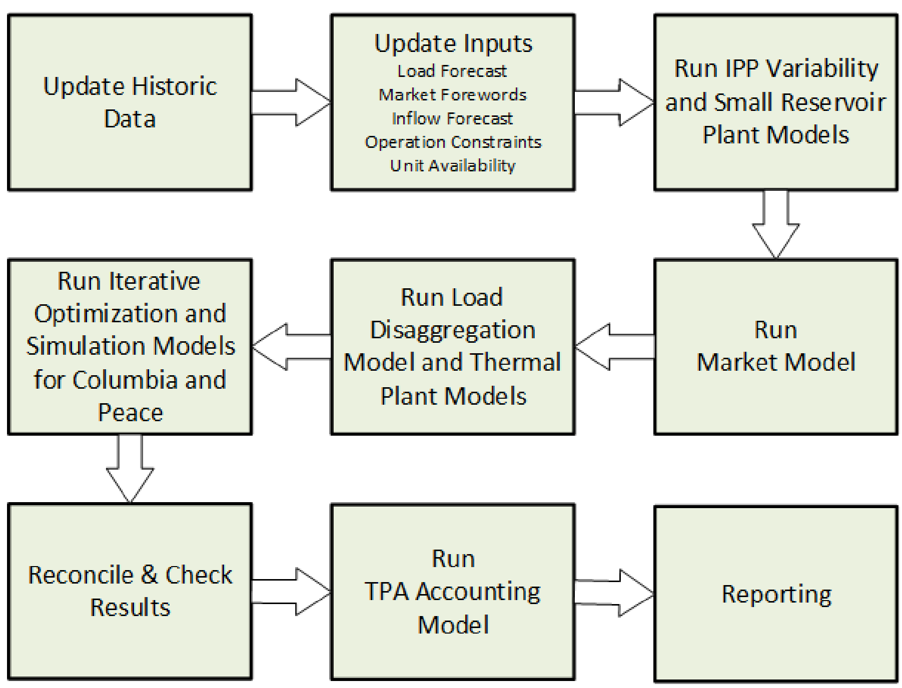


Figure DD-2 Monthly Energy Study Sequence



2.2 Inputs and Pre-Optimization Models

This section describes each of the key inputs and the model components that are used to transform the inputs into ensemble data sets that can then be used in the optimization.

2.2.1 Inflow Forecast (Input)

Inflows to each reservoir are the largest determinant of energy production and reservoir operation. Inflows are driven by a combination of rainfall, snowpack and glacier meltwater. Once the annually variable snowpack has melted (usually towards the end of summer), rainfall becomes the primary driver of reservoir inflows.

The inflow forecasts for the study horizon come from two sources. The first year comes from the seasonal inflow forecast and the remaining years come from historical records. Seasonal inflow forecasts are made at the beginning of every month, from January to August, for each of BC Hydro's 25 basins. These forecasts are in ensemble form, with one ensemble member for each historic weather sequence.

As of 2021, historic weather, inflow, and generation data exists for the period 1972 through 2020. These 49 years provide the basis for the ensemble set. The Energy Studies models require five years of inflow data. As a result, a set of five-year parallel sequences (ensembles) are created from the data that preserves any year-over-year correlation, as follows: 1972 to 1976, 1973 to 1977, 1974 to 1978, etc.

Note that to ensure a continuous sequence of five years in all ensembles, the initial year (1972) is assumed to follow the last year. This same set of 49 weather year ensembles is used in all key model inputs. The use of these weather year ensembles ensures that variability in inflows, prices, loads, and resources due to the impacts of weather are well represented in the models.

The inflow forecast is used in the IPP Variability model, the Small Reservoir and Plant Simulation models, and the Columbia and Peace Optimization models.

2.2.2 Load Forecast (Input) and Load Disaggregation Model

The load forecast is produced annually by BC Hydro's Load Forecasting team in the Energy Planning and Analytics Key Business Unit, with more frequent updates as required. This forecast consists of monthly total energy volume from sales to domestic customers plus system losses. Separate forecasts are provided for domestic load, sales to FortisBC under Rate Schedule 3808, delivery obligations to Seattle City Light under the Skagit Valley Treaty, and Fort Nelson area load.

The Energy Studies load variability model takes the load forecast from the Load Forecasting team and turns it into daily heavy load hour (**HLH**) and light load hour (**LLH**) blocks[5] in weather ensemble form (i.e., 49 separate load forecasts that are consistent with the temperatures/precipitation in those ensemble members). This process relies on analysis of the historic impacts of time of day, day of the week, and weather on the domestic load. The resulting ensemble average preserves the total annual energy volumes in the load forecast.

2.2.3 Market Forward Prices (Input) and Energy Studies Market Model

Electricity and gas prices tend to follow an annual cycle with higher prices during the colder winter months and hotter summer months, and lower prices during the spring freshet. At the beginning of each Energy Study, BC Hydro uses a set of forward market price curves for the electricity and gas prices at various North American power hubs as the basis to: 1) develop the market price forecasts generated by the market model used in the Energy Studies; and 2) value the system imports and exports output by the Energy Studies models.

[5] HLH is a 16-hour block from 7 a.m. to 10 p.m.; LLH is an eight-hour block from midnight to 7 a.m. and 10 p.m. to midnight. These correspond to the mid-Columbia market trading blocks, except for Sundays and NERC holidays, which are LLH all day, but are treated as separate blocks in the Energy Studies models.

The Energy Studies market model uses the forward curves for the North American gas market as its starting point. Based on an analysis of historic price data, the model adds variability to these prices in order to capture the expected range of uncertainty while maintaining a mean forecast that aligns with the forward curves. The aim of this process is to forecast a range of potential prices that may occur over the model time horizon.

When using the electricity price forecasts in the Energy Studies models, the modeled prices at the trading hubs are adjusted to factor in transmission costs to and from the BC Hydro system and converted to Canadian dollars where necessary.

2.2.4 IPP Forecast (Input) and IPP Variability Model

A forecast of Electricity Purchase Agreement (**EPA**) deliveries is updated each month by the Independent Power Producers (**IPP**) Portfolio Management team and used in the Energy Studies. For the majority of IPPs, forecast energy production is provided as a monthly estimate which does not account for uncertainty in inflows and energy production.

For many of the larger hydroelectric IPPs in southwest B.C. which have been in production for several years, the IPP Variability Model is used to augment the forecast to reflect uncertainty and daily variability in inflow. The single trace forecast of deliveries for these larger IPPs is replaced by an ensemble forecast that varies by inflow sequence. The mean of the sequences for each of these IPPs preserves the EPA forecast issued by the IPP Portfolio Management team. EPA cost forecasts are predetermined based on the delivery forecast and contract terms, and therefore do not impact the optimization process.

2.2.5 Generation Unit Availability Forecast (Input)

Energy production and plant capacity can be significantly affected by generation units being taken offline for maintenance and capital projects or forced out of service. Unit outages for maintenance and capital projects are accounted for in the Energy Studies. Generation unit availability forecasts are produced for the facilities that are included in the optimization process – facilities on the Peace system (GM Shrum and Peace Canyon generating stations) and Columbia system (Mica, Revelstoke and Arrow Lakes Hydro generating stations). Historic reliability data are used to adjust the availability forecasts to account for the risk of forced outages. The Generation unit Availability Forecast is also used by the Small Reservoir and Plant Simulation models.

2.2.6 Operational Constraints (Input)

Energy Studies models that simulate generating station and reservoir operations require, as an input, information on operating limits for the purpose of satisfying physical and water license requirements. In some cases, these constraints are static and do not change over time (e.g., minimum and maximum elevation limits), while in other cases they can change seasonally (e.g., fisheries flows, flood control elevations).

The Operational Constraints inputs are used in the Small Reservoir and Plant Simulation models, the Thermal Plant models, and the Columbia and Peace Optimization models.

2.2.7 Thermal Plants Model

The Energy Studies also model the operation of Fort Nelson Generating Station and the Island Generation facility, both of which are dispatched for reliability and when economic. Fort Nelson, which is not part of the BC Hydro integrated grid, is run to serve area load as well as meet Alberta market opportunities. The Energy Studies models account for the gas price, plant heat rate, carbon tax and gas transportation costs when forecasting economic dispatch from the thermal plants.

2.2.8 Small Reservoir Plant Models

This section describes the models for other generating facilities that do not get dispatched as part of the optimization models. These models are represented in Figure DD-1 as "Small Reservoir Plant Simulation Models".

2.2.8.1 Small Hydro

BC Hydro's portfolio of generation assets includes many smaller hydroelectric resources that produce energy following a seasonal cycle. Energy production at these smaller plants is modelled in the Energy Studies based on historic energy production, adjusted for outages, upgrades, and other changes in generating capability. The current water supply forecast and outage schedules are also considered.

To align the forecast with the ensembles produced by the other models, historic data for the 1972 to 2020 period is used. In the January through August period of the first study year this forecast is adjusted to account for the current water supply forecast. For the Bridge River facilities, which comprise about 40 per cent of the small hydro energy production, forecast operations for the first 12 to 18 months are used.

2.2.8.2 Kootenay

The Kootenay hydroelectric system consists of a complex arrangement of plants and storage, where the bulk of BC Hydro's flexibility lies in operating Kootenay Canal for power generation. Approximately one-half of the Kootenay Canal inflows come from upstream storage controlled by the U.S. (Libby Dam and Koocanusa Reservoir). The Energy Studies simulate the operation of the upstream storage and models the operation of Kootenay Lake using a linear programing model to maximize the value of energy produced based on the value of energy in the rest of the system.

2.2.8.3 Pend-d'Oreille

The modelled hydroelectric facilities on the Canadian portion of the Pend-d'Oreille River include Seven Mile, Waneta and Waneta Expansion plants. There is very little storage in the Canadian portion of the Pend-d'Oreille, and releases from upstream storage in the U.S. system are regulated. No optimization is performed on this system and a simulation model is run for the Energy Studies in which the Canadian plants generate energy, shaped into HLH and LLH blocks, while passing both local inflows and flows received from the upstream U.S. storage.

2.3 Models of Large Storage Reservoirs and Imports and Exports

BC Hydro's primary source of seasonal and multi-year operational flexibility are the Kinbasket Reservoir on the Columbia River and Williston Reservoir on the Peace River. Taken together, the total storage in these two reservoirs represents approximately 90 per cent of the total storage capability in the entire system. The two basins have their own unique characteristics and constraints; hence, two different models are used.

Due to the large volume of available storage, the plants on the Peace and Columbia can be dispatched to meet domestic load and to take advantage of market conditions. They can run harder (discharge more water) to meet peak domestic load demand or for export during times of high market electricity prices or can be backed down (discharge less water) for imports to take advantage of low market electricity prices.

Energy Studies models for the Peace and Columbia systems are run iteratively with the objective of maximizing CNRO (refer to section 1.4). A future improvement to the modelling will consider implementing the optimization of both basins within a single Three Reservoir (Williston, Kinbasket, and Arrow) model (refer to section 3.2).

2.3.1 Columbia Optimization Model (MUREO)

BC Hydro's primary generating resources on the Columbia River are at the generation stations located at Mica and Revelstoke (Kinbasket and Revelstoke reservoirs, respectively). Water discharged from Kinbasket Reservoir and generated at Mica Generating Station travels through Revelstoke Reservoir and generated at Revelstoke Generating Station into Arrow Lakes Reservoir. Arrow Lakes Reservoir also has a non-BC Hydro owned generating station, Arrow Lakes Hydro. Output from this plant is coordinated with the rest of BC Hydro's generation under the terms of the Keenleyside Entitlement Agreement.

In the Energy Studies, Kinbasket, Revelstoke and Arrow Lakes Reservoirs are modelled in accordance with constraints arising from the Columbia River Treaty related to firm power generation in the U.S. and flood control, as well as supplemental agreements and operating restrictions associated with fish and other non-power uses.

One of the major challenges in modelling the Columbia system involves accounting for the changing storage requirements of the Columbia River Treaty. Changes in snowpack and the timing or volume of inflow forecasts throughout both the Canadian and U.S. portions of the Columbia system can impact the constraints applied during the optimization process. The model considers reservoir elevation, turbine efficiency, generation unit availability and generating capacity of the Mica, Revelstoke, and Arrow Lakes Hydro plants.

The Columbia system is optimized using the Multiple Reservoir Energy Optimizer (**MUREO**) model. It uses a stochastic dynamic programming approach to optimize Columbia River system operations with respect to the uncertainties in inflow, residual load, and electricity price. The marginal value of energy stored in Kinbasket Reservoir is produced by this model.

2.3.2 Peace Optimization Model (MCM)

The Peace system consists of Williston Reservoir and GM Shrum Generating Station, with Dinosaur Reservoir and Peace Canyon Generating Station situated downstream. Site C will be a third dam and generating station on Peace River downstream of Peace Canyon near Fort St. John.

The Peace system is optimized using the Marginal Cost Model (**MCM**). This model also uses stochastic dynamic programming that explicitly considers the likelihood of month-to-month changes in market prices. The marginal value of energy stored in Williston Reservoir is produced by this model.

The MCM optimizes Peace operations in the context of the larger system, and assumes that energy production from GM Shrum and Peace Canyon can be varied to meet both the remaining (or, residual) load not served from other plants in the system, as well as market opportunities for energy export or import. Using energy prices obtained from the market models, the MCM optimizes the net revenue by reducing Peace energy production to permit imports during periods when prices are low and by increasing generation to serve the market during months when prices are high, in both cases ensuring that load is met.

2.3.3 System Simulation (SOPHOS)

The system simulation model SOPHOS takes the discharge releases produced by the Peace and Columbia optimization models to produce forecasts of reservoir elevations, plant discharges and energy production, spills, market imports and exports, and marginal basin prices. This model operates using a daily time step with HLH and LLH blocks and includes more details on outages and constraints than are included in the optimizers due to those models having a coarser sub-monthly time step.

2.4 Post-Processing

After the optimization and simulation modelling is complete, the 2020 TPA accounting model is used to price the system imports and exports and gas generation using the forward price curves. As noted previously, the Energy Studies produce an ensemble of forecasts. The average of these ensembles is used for the Cost of Energy forecast. The forecast cost of total water rental fees is based on the forecast of BC Hydro plant energy production and priced at the applicable water rental rates.

The System Optimization team within GSO, working with the Finance Key Business Unit, prepares and presents the Cost of Energy forecasts.

3 Development of Energy Studies Models

3.1 Development and Continuous Improvement

BC Hydro is continually improving its modelling capability and the models used in the Monthly Energy Studies models are validated and updated on an ongoing basis.[6] BC Hydro provided the following information regarding the cost of energy and the Monthly Energy Studies in BC Hydro's compliance filing to the BCUC dated April 1, 2021:[7]

- A summary of model improvements;
- A plan to update the models in the Energy Studies; and

---

[6] Refer to materials filed in previous proceedings including:
- BC Hydro's response to BCUC IRs 1.55.4 and 2.367.2 in the Fiscal 2011 Revenue Requirements Application;
- Appendix DD of the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application; and
- Subsequent compliance fillings as part of the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application dated December 1, 2020 and April 1, 2021.

[7] Refer to: https://www.bcuc.com/ApplicationView.aspx?ApplicationId=855.

- A plan to have an independent third-party test the Energy Studies Market Model.

3.2 Energy Studies Model Improvements

Changes in BC Hydro system characteristics (e.g., adding a new generating station, unit upgrades), changes in markets (e.g., addition of a carbon tax), advances in modelling techniques, and enhancements in computational power and programming languages, all contribute to the need for continual improvements in models and processes. In addition, the System Optimization team continually compares forecasts with observed data and makes improvements in the models to reduce any bias and improve the representation of the range of expected variation in the forecasts.

Current plans for Energy Studies model improvements are broken up into the following tasks that outline the expected continuous improvements over fiscal 2022 to fiscal 2027. The seven model improvement tasks are:

(a) Increase Automation of the Energy Studies Manager: Efficiency Improvements;

(b) Improve Data Transfer management in the Energy Studies Manager (**ESM**);

(c) Replace the Peace Optimizer Model;

(d) Upgrade the Columbia and Peace Simulation Model (**SOPHOS**);

(e) Update the Load Variability Model;

(f) Develop a Three Reservoir Stochastic Dynamic Programming Model (**SDP**); and

(g) Update the Cloud Computation Interface: Amazon Web Service (**AWS**).

In addition, BC Hydro will:

(a) Update the Short-Term Model: Ultralight;

(b) Provide an external review of the Market Model and report on the results;

(c) Develop a process and implement benchmarking and report on the results; and

(d) Develop a process and implement backtesting and report on the results.

The completion of each task, for the Energy Studies (a) through (g), above, generally addresses some or all of the following objectives:

- Reduce execution time to run the models;
- Reduce the amount of person resources needed to run the models;
- Improve data transcription and transfer between large databases;
- Increase model accuracy;
- Facilitate the ability to run different and parallel scenarios;
- Improve error handling during the Energy Studies Manager process;
- Improve reporting capabilities; and
- Reduce issues associated with aging programming environment or legacy code and documentation.

Directive 4 in the BCUC's Decision on the Previous Application directed BC Hydro to provide an update on the timeline for improvements to the Energy Studies models (referenced in Table 11 of the Decision) and explain any changes to the timeline.[8] In the Decision, the BCUC noted that it was concerned about the length of time it will take to complete the benchmarking and backtesting. BC Hydro has considered the BCUC's feedback and advanced the schedule for backtesting by one year. Under this revised schedule there is less ability for the team to respond to any new issues that may arise. Further compression of the schedule for benchmarking is not feasible

[8] Directive 4; BCUC Decision and Order No. G-187-21, BC Hydro Fiscal 2022 Revenue Requirements Application (June 17, 2021), page 23.

without impacting other scheduled tasks. The table below provides the current timeline for each of the planned improvements.

Table DD-1 Monthly Energy Studies Models Tasks (Update to Table 1 in the April 2021 Compliance Filing)[9]

Directive and Tasks		Fiscal 2022				Fiscal 2023				Fiscal 2024				Fiscal 2025				Fiscal 2026				Fiscal 2027			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
	Revenue Requirements																								
#9(2)	ESM Efficiency																								
#9(2)	ESM Data Transfer																								
#9(2)	Peace Optimizer																								
#9(2)	SOPHOS Upgrades																								
#9(2)	Load Variability Model																								
#9(2)	Three Reservoir SDP																								
#9(2)	Cloud Computing (AWS)																								
#9(2)	Ultralight (Short Term Model)																								
#9(3)	Market Model (Review)																								
#10	Benchmarking																								
#10	Backtesting																								

---

9 Purple blocks are projects underway and/or on schedule. Pink blocks are used to indicate implementation timing that is less certain. Anticipated Revenue Requirements Application preparation and proceeding times are included as these applications require significant effort from the same group of subject matter experts that support the Energy Studies models improvement tasks. The advanced backtesting timing (purple) is shown relative to the original (Grey) timing submitted previously in BC Hydro's Compliance Filing to the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application dated April 1, 2021.
Refer to: https://www.bcuc.com/ApplicationView.aspx?ApplicationId=855.

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix EE

BC Hydro's ICS Cybersecurity Risk Mitigation Plan

BC Hydro's Industrial Control Systems (ICS) Cybersecurity Risk Mitigation Plan

Cybersecurity in BC Hydro's facilities containing Industrial Control Systems (**ICS**) has so far been focused on those stations where Critical Infrastructure Protection (**CIP**) Mandatory Reliability Standards are applicable. Currently 186 stations are subject to CIP standards for cybersecurity and are classified as high, medium or low depending on their potential to impact the reliability of the Bulk Electricity System (**BES**) across the Western Interconnection System. Additionally, there are another approximately 150 stations that are not subject to CIP standards (referred to as **non-CIP**). Even though a cyber incident at one of these 150 stations wouldn't impact the reliability of the BES, it could potentially lead to a localized power outage and reputational damage to BC Hydro.

The OAG audit found that BC Hydro has insufficient cybersecurity controls in place for ICS that are not covered by CIP Mandatory Reliability Standards. There were three high-level recommendations; to assess the risk over the ICS environment, to maintain an inventory of the ICS systems and devices, and to implement detection and monitoring capability for ICS systems and devices.

In response to the first recommendation, BC Hydro engaged an expert third party service provider to carry out a cybersecurity risk assessment of all ICS, located at approximately 150 stations, that were not in scope of CIP. The assessment identified a number of possible cybersecurity risk mitigation activities. Based on this report, BC Hydro implemented mitigation controls at stations containing ICS and identified as having a high-risk vulnerability to unauthorized access. The remainder of the mitigation recommendations will be considered as part of a multi-year program to address each of the non-CIP stations.

The second and third recommendations from the OAG audit are currently being implemented across our CIP stations in advance of its application to non-CIP stations. More specifically, inventory and configuration management are in place for all high and medium impact stations and are within scope for the current CIP initiative CIP-003-8 (referred to as the **CIP v7** Project) for all low impact sites. Monitoring and detection is in place for high and medium sites and this will be enhanced and extended to the 131 low impact sites during the CIP v7 Project. The recommendation to monitor and detect in real-time is dependent on the network capability of the individual sites and this will be considered as part of the remediation for each station. Once the high, medium and low impact stations have been addressed, BC Hydro will apply the same approach to the non-CIP stations containing ICS.

OAG AUDIT RECOMMENDATIONS

We recommend that BC Hydro

1. Assess cybersecurity risk over its entire ICS environment to ensure appropriate detection and response measures are implemented.
2. Maintain an inventory of hardware and software components, including their configuration, settings for all ICS-related systems and devices, regardless of whether they currently fall under the mandatory standards.
3. Implement detection mechanisms and monitor, in real time, for anomalous activity on ICS-related systems and devices not currently under the mandatory standards.

BC Hydro's multi-year plan is to establish inventory, monitoring and detection mechanisms first across the CIP environment and then the remaining ICS environment where practicable. The practice of mitigating risk to As Low as Reasonably Practicable (**ALARP**) is well-established as a risk management approach. In this case, BC Hydro will implement those recommendations that can be done (e.g., there is connectivity available for remote monitoring) and are reasonable to do (e.g., the risk outweighs the cost). BC Hydro notes that implementing the OAG recommendations for the non-CIP classified stations is outside of the requirements for CIP compliance.

Plan Summary:

- Extend and enhance inventory practices, monitoring and detection technologies and services during the CIP v7 Project for low impact CIP stations;
- Develop a business case, prioritize the non-CIP stations and develop a remediation schedule; and
- Implement inventory, monitoring and detection mechanisms across the non-CIP stations containing ICS where practicable. This is dependent on whether there is connectivity available for remote monitoring and it's reasonable to do so (e.g., the risk outweighs the cost).

PROGRAM PLAN

Scope

The British Columbia Utilities Commission (**BCUC**) has adopted the CIP standards for BC Hydro which specifies requirements for high, medium and low impact facilities as defined by CIP-002. The scope of this program includes approximately 150 stations containing ICS that are not subject to CIP standards

These sites are geographically spread across the province of British Columbia and vary in the number of customers for which they supply power. BC Hydro's Power Systems Planning and Operations teams use a "criticality" categorization for sustaining and responding to reliability issues at these sites based on potential impact to customers. The OAG correctly identified the potential impact of a cybersecurity incident at a non-CIP site to be reliability of service to customers. These sites do not individually have the potential to impact the BES but could impact parts of the local power systems network. It is highly unlikely that an attack originating at one of these sites would be able to access BC Hydro's telecommunications network and impact the rest of BC Hydro's operations. Given the potential impact of a cybersecurity incident is to reliability of service to customers, we will use the "criticality" categorization to prioritize the non-CIP sites for cybersecurity risk mitigation activities.

Approach

BC Hydro's approach is to build on the work being done to meet the CIP requirements and to extend this into the non-CIP sites. BC Hydro completed some immediate remediation activities at non-CIP sites that were identified through the external risk assessment completed in 2019. The remaining recommendations from the OAG audit and the risk assessment will be addressed as part of this program plan.

<u>Develop inventory processes, monitoring and detection architectures and designs during project for CIP v7 low impact sites</u>

The CIP v7 Project will implement many of the controls at BC Hydro's low impact CIP sites that were recommended through the OAG audit. The project will enhance the process and tools for capturing and maintaining an inventory of CIP cyber assets. It will also implement monitoring and detection of activity at the CIP site electronic perimeter for those sites having external routable connectivity. The processes, tools, architecture and designs developed as part of this project will also serve to meet the needs of the non-CIP cyber assets and sites.

<u>Develop business case for non-CIP facilities and include in maintenance program</u>

Following the development and deployment of the CIP requirements for low impact sites, BC Hydro will initiate a prioritized maintenance program to address the non-CIP facilities. BC Hydro will use its current method for categorizing transmission and distribution sites to prioritize the work. A business case will be developed for a continuous improvement work program to assess and remediate sites. The decision to remediate a site will be based on feasibility, cost and risk.

Implement inventory, monitoring and detection mechanisms across the non-CIP ICS environment

As each site is assessed an inventory will be taken and a work package developed to address the remediation recommendations where practicable. There are approximately 150 sites that fall into the non-CIP category. It is expected that this work will take approximately three years based on the number of sites. This timing reflects the use of contractors in addition to BC Hydro's own staff. It is unlikely that this timeline can be accelerated due to resource capacity constraints including BC Hydro management capacity to plan and oversee the work.

To maximize efficient use of resources, assessment and remediation activities will be timed to coincide with regularly scheduled maintenance work where possible.

Schedule

The following schedule is expected for the program.

Fiscal 2022	Fiscal 2023	Fiscal 2024	Fiscal 2025	Fiscal 2026	Fiscal 2027
CIP v7 – LOW impact stations					
		Business case and prioritization	Non-CIP – ICS stations		

The existing CIP v7 Project includes 131 low impact sites (there are 2 others categorized as low impact that are not yet in service) and is expected to take three years to complete. The inventory and design work are expected to be completed in fiscal 2022 with the implementation of controls expected to be complete in the third quarter of fiscal 2024. The implementation is expected to cost approximately $40 million with an additional $4 million per year to sustain. Funding for this work is included in BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, refer to Appendix I and J (Planning ID: 901592) and Chapter 5, section 5.7.

Implementation of the non-CIP ICS program includes approximately 150 stations and is expected to take a further three years to complete. The program will use the methods, processes and tools developed for CIP v7 and many of the same resources both internal and external to BC Hydro. Business case development and prioritization will start in fiscal 2024 such that the program can begin implementation immediately after completion of the CIP v7 Project. The program will prioritize the non-CIP sites based on BC Hydro's current method for categorizing the criticality of transmission and distribution sites. BC Hydro expects to address the highest priority sites within the first year of the project. BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application includes some capital expenditure funding for this work within Line Asset Planning.

Resources

This program will be initiated by BC Hydro's Asset Planning KBU and will utilize both internal and external maintenance teams to complete the work.

Project Delivery Risks

Risk	Impact	Mitigation
Funding	Funding for the program has not yet been secured and will need to be in place prior to commencing work.	A business case will be developed to secure funding prior to starting the work during the latter stages of the CIP v7 Project. The business case will require approval consistent with BC Hydro's financial policy and may require a submission to the BCUC.

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix FF

Dam Safety Vulnerability Index and Long-Term Capital Plan

Table of Contents

List of Figures

List of Tables

1 Introduction

BC Hydro provides this appendix in response to Directive 12 from the BCUC's Decision on the Previous Application. Directive 12 directed BC Hydro to file its dam safety vulnerability index for all dams and its aggregate dam safety vulnerability index and a long-term capital plan for ensuring the sustainable safety of all its dams.

Section 2 below provides the requested dam safety vulnerability indices (**Vulnerability Index**), while section 3 provides BC Hydro's dam safety long-term capital plan.

2 Dam Safety Vulnerability Index

This section includes an overview of the Vulnerability Index and how BC Hydro uses it in the safe management of its dams.

2.1 BC Hydro Uses the Dam Safety Vulnerability Index to Characterize All Deficiencies in BC Hydro's Dams

BC Hydro uses the Vulnerability Index to characterize all deficiencies in BC Hydro's dams. BC Hydro's Dam Safety program defines a deficiency to be an inadequacy or uncertainty of concern in the capacity of the dam to meet its performance goals in accordance with established norms of dam safety practices, as described in various guidelines and bulletins published by the Canadian Dam Association, the International Commission on Large Dams, and other similar organizations and authorities. The "dam" in this context is defined as all physical features and structures necessary to retain the reservoir and ensure the controlled passage of all flows through, around and beyond the actual constructed barrier.

BC Hydro's dams have been, and are, built on the basis of good industry practice existing at the time of their construction. Post construction, BC Hydro subjects its dams to regular and continuing surveillance and monitoring to identify deficiencies in design, construction or performance that may compromise the overall integrity of the dam and its ancillary systems and their ability to safely retain and convey water. As our dams age and as scientific knowledge advances, deficiencies can arise in three ways:

- Firstly, deficiencies arise through wear and tear, as explained in Chapter 6, section 6.4.1.4 of this application, and are identified through regular inspections and condition assessments;
- Secondly, deleterious conditions in dams develop over time and are identified by our surveillance activities and verified through engineering investigations. Examples are excessive seepage through embankment dams or abutments with potential for internal erosion, or excessive uplift pressures that can destabilize concrete dams; and
- Finally, deficiencies can arise as good practice evolves and expectations become more stringent. For example, with the evolution of seismic design standards over the past several decades, dams that were designed or upgraded to meet previous expectations for earthquake load resistance may not meet current seismic design expectations and consequently be identified as having a deficiency under seismic loading.

BC Hydro follows international and Canadian best practices in dam safety management to identify and characterize deficiencies associated with its dams. In so doing, BC Hydro uses a standards-based characterization of the degree of concern that exists with respect to the integrity of the dam, expressed in terms of a Vulnerability Index. As discussed in section 2.4 below, the Vulnerability Index characterizes the degree to which the observed or expected performance of a feature of the dam deviates from what is required or minimally desired by current good practice and the frequency at which the dam will be subjected to conditions that stress the feature accordingly.

2.2 BC Hydro's Current Dam Safety Vulnerability Index Ratings

BC Hydro's Dam Safety Vulnerability Index for all dams and aggregated Dam Safety Vulnerability Index are provided below in Figure FF-1 and Figure FF-2, respectively. Identified deficiencies are broken out into Actual Deficiencies and Potential Deficiencies in Figure FF-2. In Figure FF-1, Actual Deficiencies are further broken out into Actual Normal (**AN**), Actual Unusual (**AU**), and Spillway Reliability Deficiencies, while Potential Normal (**PN**) and Potential Unusual (**PU**) Deficiencies are reported together. These types of deficiencies are described in section 2.3 below. The determination of the Vulnerability Index ratings is described in section 2.4 below.

1 **Figure FF-1 Dam Safety Vulnerability Index Ratings**
2 **for BC Hydro Dams as at June 30, 2021**

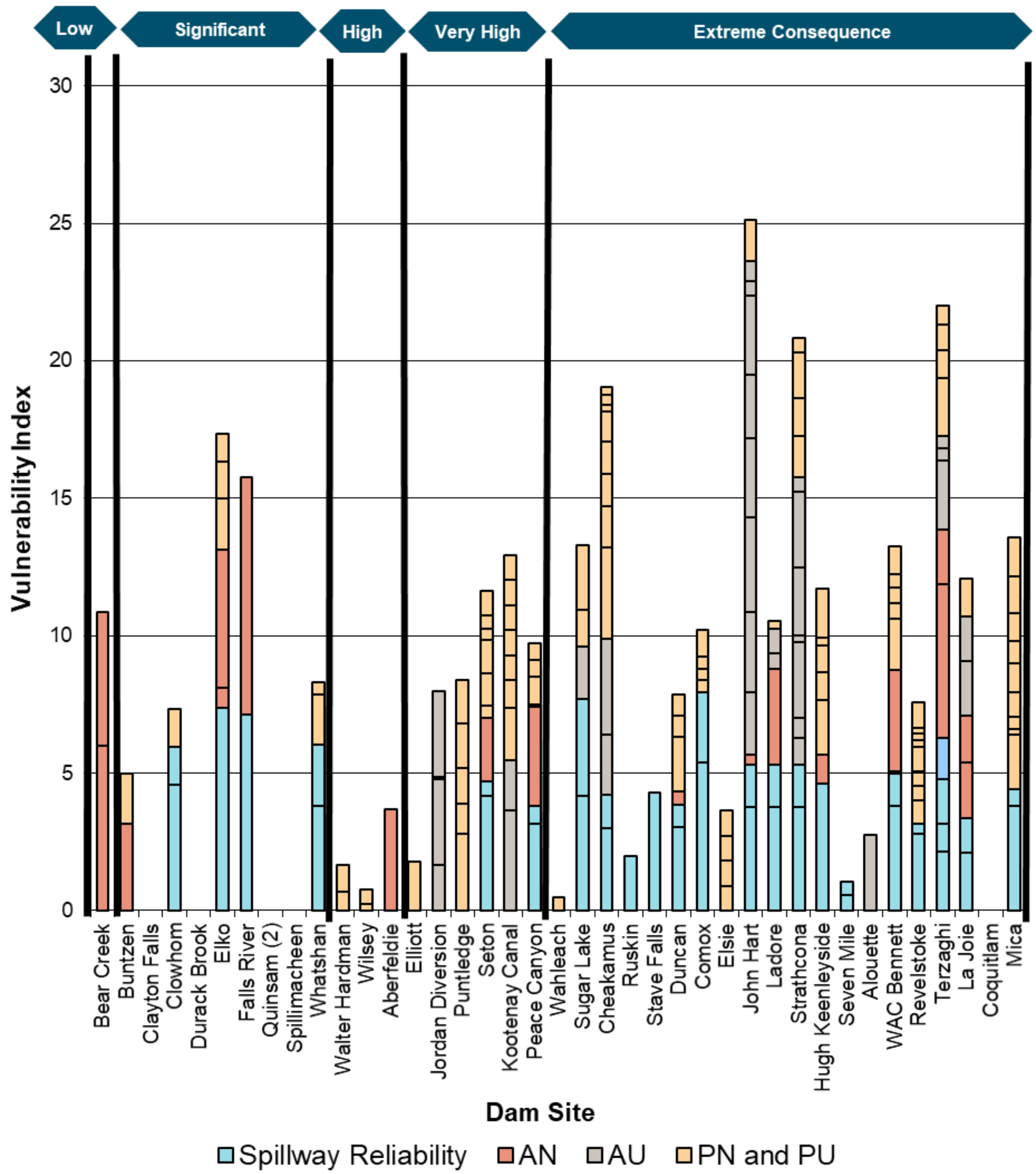
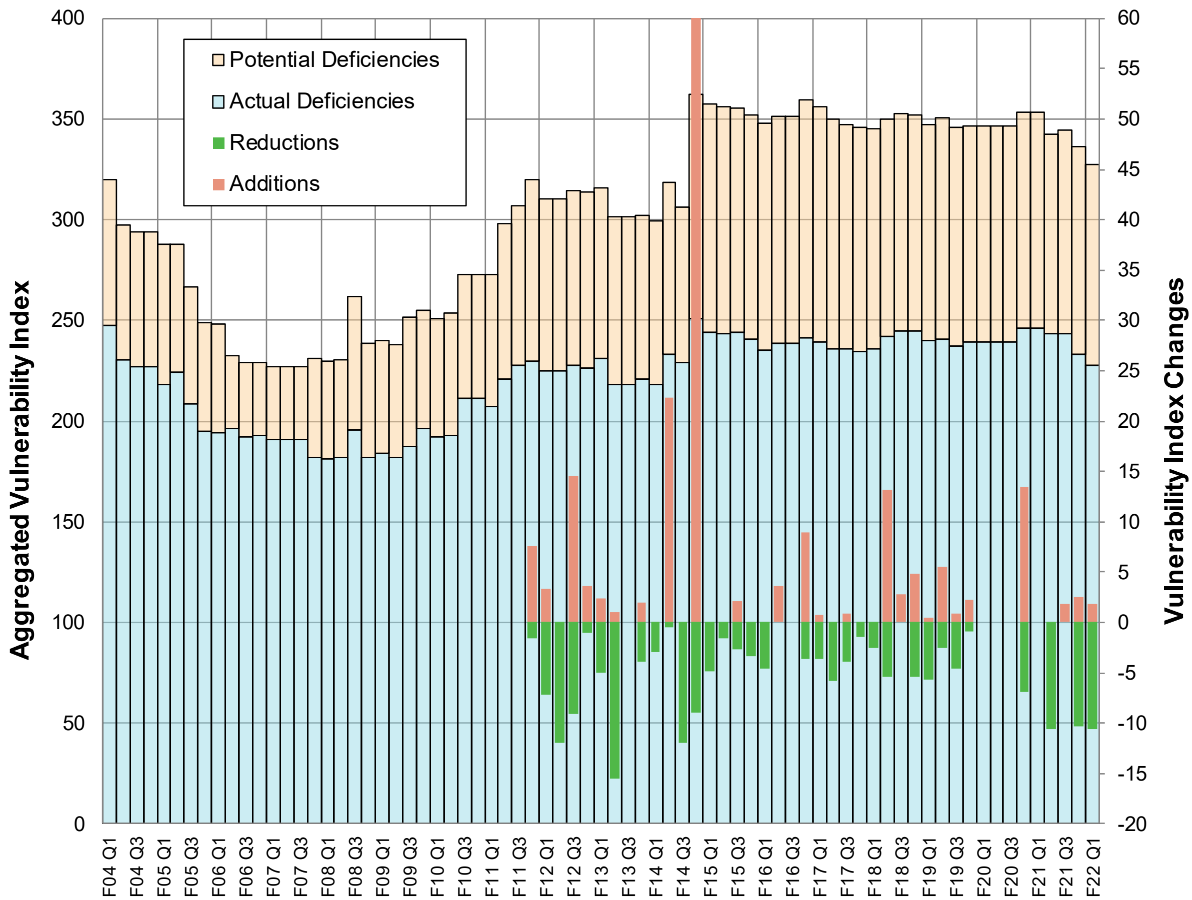


Figure FF-2 Aggregated Dam Safety Vulnerability Index Ratings as at June 30, 2021



2.3 Types of Deficiencies in the Dam Safety Vulnerability Index

As plotted in Figure FF-2 above, deficiencies are differentiated as Actual Deficiencies or Potential Deficiencies:

- Actual Deficiencies are inadequacies in performance that have been confirmed to exist through an appropriate form of analysis or for which the character or magnitude of residual uncertainties are such that dam safety improvements are necessary; and

- Potential Deficiencies are concerns pertaining to inadequacies in performance that have not yet been confirmed as Actual Deficiencies but are expected to be, or that are of such a nature that, unless they can be demonstrated to not exist, dam safety improvements are necessary.

Deficiencies are further differentiated as pertaining to Normal loading conditions, Unusual loading conditions, or Spillway Reliability.

- Normal loading conditions are the loading conditions that are applied to the dam either continuously or that can be reasonably expected to occur over the operating life of the dam. These include loading conditions for natural hazards such as floods and earthquakes with an Annual Exceedance Frequency (**AEF**)[1] of 1/500 or greater.[2] They also include loads that would occur as a result of operator error or the failure of some protective system necessary to deal with normal loads.
- Unusual loading conditions are those due to natural hazards with an AEF of less than 1/500, as well as unforeseeable loading conditions, including those loads not recognized in best design practices.
- Spillway Reliability Deficiencies are those related to the reliable operation of spillway gates and other discharge devices (e.g., valves) required to control reservoir levels and pass required downstream flows in response to high inflows and/or generating unit outages.

---

1 Annual Exceedance Frequency is the annualized frequency at which some prescribed event will occur or be exceeded. The greater the value of an event's AEF, the more commonly it occurs. For example, an event with an AEF of 2 would be expected to occur, on average, twice per year; an event with an AEF of 1/500 would be expected to occur, on average, once every 500 years; and an event with an AEF of 1/10,000 would be expected to occur once every 10,000 years.

2 A natural hazard with an AEF of 1/500 would have a 10 per cent probability of occurring or being exceeded over a 50-year period or a 20 per cent probability of occurring or being exceeded over a 100-year period. As dams generally have life spans that are at least as long as 50 to 100 years, loadings from natural hazards with AEF of 1/500 or greater can be reasonably expected to occur over a dam's operating life.

Differentiated in these two ways, deficiencies are fully categorized as being Actual Normal Deficiencies, Actual Unusual Deficiencies, Potential Normal Deficiencies, Potential Unusual Deficiencies, and Spillway Reliability Deficiencies. As previously noted, Spillway Reliability Deficiencies are included as Actual Deficiencies in Figure FF-2.

2.4 Computing the Vulnerability Index Rating for a Deficiency

The Vulnerability Index rating for any given deficiency is determined by multiplying a factor representing the deficiency's Magnitude of the Concern by a factor representing the Frequency of Stressing the Feature:

$$\text{Vulnerability Index} = \text{Magnitude of Concern Factor} \times \text{Frequency of Stressing the Feature Factor}$$

The determination of the Magnitude of the Concern and Frequency of Stressing the Feature are discussed below.

2.4.1 Determining the Magnitude of Concern Factor

In determining the factor for Magnitude of Concern of an Actual Deficiency, each of three performance characteristics is assigned a value on a scale of 0 to 1, as follows:

(a) Magnitude of the Gap: The magnitude of the gap between the actual performance capability of the feature of concern and its required or minimum desired capacity. If the feature has 90 per cent of the required or minimum desired capacity, then the inferred gap is 10 per cent and a value of 0.1 is assigned. If the feature has 10 per cent of the required or desired minimum capacity, then the gap is 90 per cent and a value of 0.9 is assigned;

(b) Criticality of the Feature: The criticality of a feature in the assurance of the safety of a dam is determined by the design of the dam and whether or not the feature is "in series" or "in parallel" in the safe functioning of the dam. For a feature that is in series with no parallel compensating features, the assigned value will be 1 if the feature is essential for safety and 0 if it is not essential for safety. On the other hand, if the feature is part of a parallel subsystem, where there are other compensating features, then the assigned value is determined by the extent to which the individual feature contributes to the overall function of the total capacity of the parallel subsystem. Thus if 70 per cent of the functioning of a parallel subsystem is derived from an individual feature, then a value of 0.7 is assigned to the criticality of that feature; and

(c) Magnitude of Weakness of Interim Risk Controls: The magnitude of weakness of interim risk controls is the ineffectiveness of interim risk controls that have been established to manage risks associated with the deficiency until a permanent solution can be implemented. If no interim risk controls have been established, or it is not possible to establish interim risk controls, then a value of 1 is assigned. If the interim risk controls are as effective as a permanent solution, then a value of 0 is assigned. In all other cases, the value assigned is the same as the Magnitude of the Gap with the interim risk controls in place.

The Magnitude of Concern is the product of the three values described in (a) through (c) described above:

$$\begin{aligned}\text{Magnitude of Concern} \;=\; & \text{Magnitude of the Gap} \times \\ & \text{Criticality of the Feature} \times \\ & \text{Magnitude of Weakness of Interim Risk Controls}\end{aligned}$$

The Magnitude of Concern Factor for an Actual Deficiency is computed by taking the cube root of the computed Magnitude of Concern and multiplying by 10.

$$\text{Magnitude of Concern Factor}|_{\text{Actual Deficiency}} = 10 \times \sqrt[3]{(\text{Magnitude of Concern})}$$

In the case of Potential Deficiencies, the Magnitude of Concern is assigned subjectively in part because the information available concerning the physical nature and extent of the concern is inconclusive, and the Magnitude of Concern Factor is computed by taking the cube root of the assigned Magnitude of Concern and multiplying by 5.

$$\text{Magnitude of Concern Factor}|_{\text{Potential Deficiency}} = 5 \times \sqrt[3]{(\text{Magnitude of Concern})}$$

2.4.2 Determining the Frequency of Stressing the Feature Factor

The Frequency of Stressing the Feature is determined directly from load-frequency analysis and is expressed as an AEF. Very rare loading conditions with AEF's of less than 10^{-4} are assigned an AEF of 10^{-4}. The Frequency of Stressing the Feature Factor is determined from:

$$\text{Frequency of Stressing the Feature Factor } = 1 - [0.1 \times \ln 1/\text{AEF}]$$

2.5 The Vulnerability Index Is Routinely Updated

The Vulnerability Index is a dynamic measure that is routinely updated as part of BC Hydro's Dam Safety Program. BC Hydro's surveillance activities and the Dam Safety Reviews provide the principal means of identifying deficiencies, rating their magnitude and determining the frequency of loading, or stressing. The Vulnerability Index rating is updated when new information pertaining to the deficiency is obtained. Dam Safety investigations and the Dam Safety capital projects provide the primary means for updating the data on the Magnitude of the Concern and the Frequency of Stressing. Upon completion of a Dam Safety investigation or a Dam Safety project, new information is generated and used to update the Magnitude of Concern and/or the Frequency of Stressing to reflect a physical change to the asset or a better understanding of the issue. Thus, the Vulnerability Index rating for a deficiency will change, and is tracked, over time.

2.6 The Vulnerability Index in Portfolio Risk Management

Since Vulnerability Index ratings are assigned to individual dam safety deficiencies for each dam, the sum of the individual Vulnerability Index ratings provides a measure of the safety status of that dam at the time that the Vulnerability Index is assigned, and subsequently when it is updated.

For each dam, the Vulnerability Index ratings associated with all characterized deficiencies are aggregated and charted, as in Figure FF-1 above to provide an overall Vulnerability Index for the dam. Since the Vulnerability Index for a dam is the aggregate of the vulnerabilities of individual components, features and functions, the relative importance of the individual vulnerabilities can be considered in decision-making.

With no factor relating to the consequences of failure, the Vulnerability Index is not a proxy for risk. Risk is estimated by sorting the dams according to their consequence classifications within the Dam Safety Regulation[3], with risk inferred to be greater for vulnerabilities in higher consequence dams as one moves across the classifications from left to right in Figure FF-1.

Just as the Vulnerability Index for a single dam is the aggregate of the vulnerabilities of its individual components, the Vulnerability Index of the fleet of dams is expressed as the aggregate of the vulnerabilities of the individual dams. The Vulnerability Index ratings associated with all characterized deficiencies on all dams are aggregated and charted, as in Figure FF-2 above, to provide an overall Vulnerability Index for the fleet of dams. The aggregate Vulnerability Index is plotted over time to show the relative risk position of BC Hydro's fleet of dams.

[3] B.C. Reg. 40/2016, Water Sustainability Act, Dam Safety Regulation: https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/40_2016

As it is the intent of BC Hydro to not allow an overall increase in the dam safety risk profile, the ongoing rate of decrease should offset the future Vulnerability Index increases, and this balance is used to set and monitor the Dam Safety projects in the 10-year capital plan on an ongoing basis.

3 Dam Safety Long-Term Capital Plan

BC Hydro's Dam Safety long-term capital plan is derived from BC Hydro's Fiscal 2022 to Fiscal 2031 Capital Plan (**Capital Plan**), which was approved by the Executive Team and presented to the Capital Projects Committee of BC Hydro's Board of Directors in June 2021.[4] Based on the Capital Plan:

- BC Hydro is expecting an increasing level of investment in Dam Safety over the 10-year period;
- Dam safety risks, strategic investments in assets, and other operational considerations are balanced in capital planning using a staged prioritization approach; and
- BC Hydro is investing extensively in the safety of its dams.

BC Hydro expands on each of these points below.

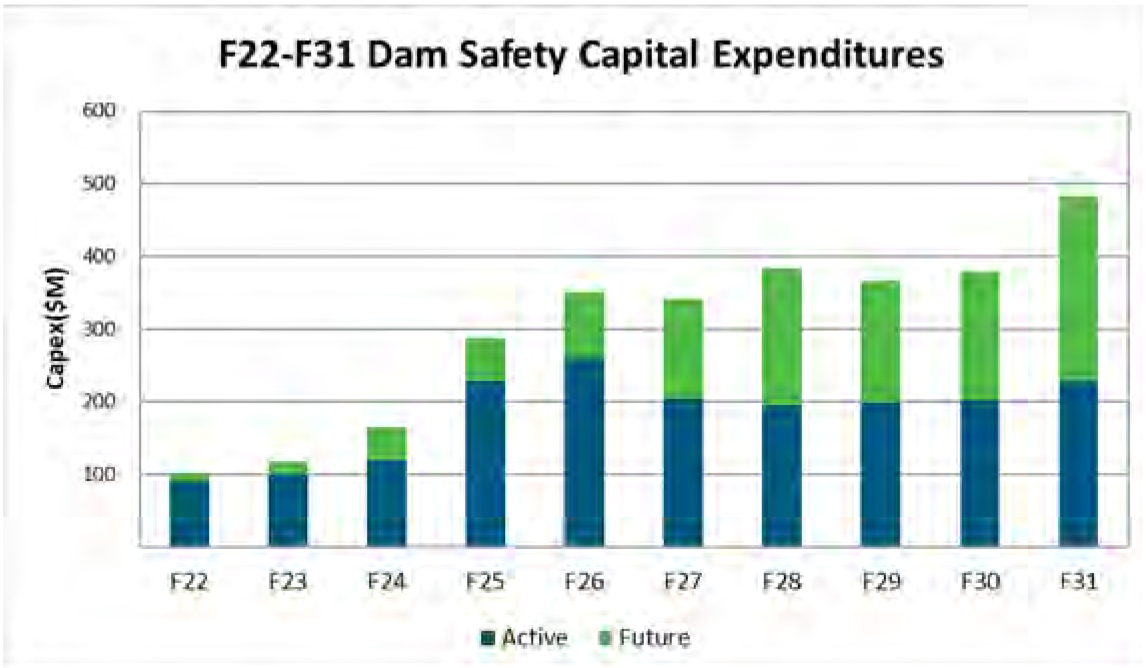
3.1 BC Hydro Is Expecting an Increasing Level of Investment in Dam Safety over the 10-Year Period

As shown in Figure FF-3 below, approximately 60 per cent of the Dam Safety expenditures in the Capital Plan are related to active investments (shown in blue), which are projects that are in the Identification, Definition or Implementation phase of the project delivery lifecycle. The remaining 40 per cent are for future investments (show in green), which are projects that had not been initiated at the time of the Capital Plan. In order to get an overall portfolio perspective, single point forecasts

[4] For more detail on the Capital Plan, see BC Hydro's 10 Year Capital Plan memo in Appendix H.

are required for all projects in all phases of the project lifecycle, including future projects. For future projects, a planning allowance,[5] is used because no formal cost estimate is available.

Figure FF-3 Fiscal 2022 to Fiscal 2031 Dam Safety Forecast Capital Expenditures



The Dam Safety portfolio consists mainly of large multi-year projects and, as a result, is subject to fluctuations in year-over-year spend. A significant portion of the planned Dam Safety expenditures in fiscal 2022 to fiscal 2031 are driven by the detailed design and progression to Implementation phase of a number of large projects, including: John Hart Seismic Upgrade, Strathcona Upgrade Discharge, Ladore Spillway Seismic Upgrade, and La Joie Dam Improvements.

5 Planning allowances are single values (rather than ranges) required to support long-term capital planning. Planning allowances are used when a project is not sufficiently advanced to have a preferred alternative, and there is insufficient information on the scope and schedule to establish a complete total project cost estimate. The planning allowance is prepared based on historic information pertaining to similar projects, and input from subject matter experts.

3.2 Dam Safety Risks, Strategic Investments in Assets, and Other Operational Considerations Are Balanced Using a Staged Prioritization Approach

As described in Chapter 6, section 6.4.1.4 of this application, Dam Safety projects are focused on mitigating safety risks associated with dams and other water conveyance or water retention infrastructure, as well as addressing deterioration and loss of serviceability of those assets. The Dam Safety portfolio includes all water retention and conveyance assets, including those that convey water to generating units, and related ancillary assets that support those functions.

An initial consideration in capital planning is to prioritize risk reduction investments on deficiencies that are associated with high Vulnerability Index ratings and on the right side of Figure FF-1, i.e., associated with Extreme and Very High consequence dams. An example of an investment so prioritized is the recently completed Ruskin Dam and Powerhouse Upgrade project, for which the aggregated Vulnerability Index was more than 20 and is now approximately two (see Figure FF-1). Another example is the trio of projects[6] now underway on the main Campbell River System dams – John Hart, Ladore and Strathcona – which collectively comprise the largest current vulnerability in BC Hydro's fleet of dams.

The Campbell River System projects also exemplify another prime consideration for prioritization: whether there exist effective interim risk controls that can be implemented to manage the risks until the deficiencies can be permanently addressed through an upgrade. In the case of the Campbell River System facilities, and particularly the identified seismic deficiencies at John Hart Dam, no interim risk controls were identified that would allow for other projects to be prioritized above them. In contrast, the seepage and seismic deficiencies at La Joie Dam are being

[6] John Hart Dam Seismic Upgrade project, Ladore Dam Spillway Gates Upgrade project, and Strathcona Dam Discharge Upgrade project.

adequately controlled by having lowered Downton Reservoir behind the dam which has allowed the upgrades to this dam to follow those on the Campbell River system.

Consideration is further given to the prioritization of projects where greater reductions in vulnerabilities can be realized for lesser financial investment, i.e., a conventional cost-to-benefit consideration. This type of analysis was employed in prioritization of risk reduction projects on the Campbell River system and is described in BC Hydro's February 15, 2019 Rebuttal Evidence to the evidence filed by the Commercial Energy Consumers Association of British Columbia in the Review of the Regulatory Oversight of Capital Expenditures and Projects[7].

Additionally, prioritization of projects must consider sequencing of investments with other planned work and the precedence of enabling projects. For example, the GMS – Spillway Rock Slope Stabilization project was implemented and completed in fiscal 2013 to enable safe access to the spillway chute at WAC Bennett Dam and the subsequent GMS – Bennett Dam Spillway Chute Upgrade project that was completed in fiscal 2017.

Resource availability is always a consideration in developing a capital plan. Regardless of financial resources, there are finite limits to the numbers of expert engineering and construction resources that can be brought to bear on the complex and highly technical projects that comprise the Dam Safety portfolio. Even where external consultants and contractors are employed, proper and diligent oversight of those external resources requires the time of BC Hydro's internal experts. Therefore, a mix of project types that doesn't engage in too much of one type of work and rely too heavily on one type of expert or specialized resource is also sought.

Finally, BC Hydro's capital plan for its fleet of dams must also provide for the inclusion of projects beyond those that remediate physical deficiencies in the dams.

[7] British Columbia Hydro and Power Authority Review of the Regulatory Oversight of Capital Expenditures and Projects, Exhibit B-15.

It must also include investment for improvements of infrastructure deficiencies (e.g., addition, replacement or enhancement to dam monitoring instrumentation, improvements to dam access) and management of hazards to the dams (e.g., monitoring instrumentation and/or drainage of reservoir slopes). Additionally, assets pertaining to the conveyance of water to generating units (e.g., penstocks, valves, intake and maintenance gates, hoists) have recently been added to the Dam Safety portfolio, and BC Hydro's capital plan must also include projects related to recoating, refurbishing or upgrading those assets. As a result, not all Dam Safety investments will have an associated Vulnerability Index reduction.

3.3 BC Hydro is Investing Extensively in the Safety of its Dams

The subsequent tables provide a listing of dam safety projects included in the Capital Plan. For projects beginning after the Test Period the tables have been filtered by order of magnitude of capital expenditure for additional context.

For projects in Future or Identification phase, the Authorized Amount / Engineering Estimate and Forecast In-Service Date are listed as To Be Determined (**TBD**) for the following reasons:

- For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined; and
- In Identification phase, several identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule and cost.

As a result, Authorized Amount / Engineering Estimate and Forecast In-Service Date are provided only for projects in the Definition phase and later phases.

Table FF-1 Dam Safety Projects with Capital Expenditures in the Fiscal 2023 to Fiscal 2025 Test Period

IPID	Project	Type	Phase	Forecasted ISD	Authorized Amount[8] / Engineering Estimate[9] ($ million)	Name of Strategy, Plan or Study to which Project is Linked
G000640	Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment	Sustaining	Implementation	F2023	43	Coquitlam-Buntzen System Facility Asset Plan
G000489	Bridge River 2 - Strip and Recoat Penstock 2 Interior	Sustaining	Implementation	F2023	35	Bridge River Facility Asset Plan; Generation Asset Management Strategy - Penstock Recoating
G000057	Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)	Sustaining	Implementation	F2023	24	Cheakamus Facility Asset Plan; Generation Asset Management Strategy - Penstock Recoating
G003129	Revelstoke Replace Downie Slide Instrumentation	Sustaining	Implementation	F2022	20	Revelstoke Facility Asset Plan
G000585	John Hart Dam Seismic Upgrade	Sustaining	Definition	F2030	739 - 432	Campbell River Systems Engineering Assessment; John Hart Facility Asset Plan
G000525	Strathcona Upgrade Discharge	Sustaining	Definition	F2027	337 - 194	Campbell River Systems Engineering Assessment. Strathcona Facility Asset Plan
G000668	Ladore Spillway Seismic Upgrade	Sustaining	Definition	F2028	269 - 155	Campbell River Systems Engineering Assessment; Ladore Facility Asset Plan

8 Authorized Amount is the “Authorized” total capital cost of projects in the Implementation Phase.
9 Pre-Implementation cost estimates are provided where an engineering estimate is available for projects in the Definition Phase.

IPID	Project	Type	Phase	Forecasted ISD	Authorized Amount[8] / Engineering Estimate[9] ($ million)	Name of Strategy, Plan or Study to which Project is Linked
G000657	Comox - Puntledge Flow Control Improvements	Sustaining	Definition	F2025	57 - 34	Puntledge Facility Asset Plan
G003555	W.A.C. Bennett Dam Seal Low Level Outlets	Sustaining	Definition	F2026	53 - 32	G.M. Shrum Facility Asset Plan
G000195	Mica - Intake Gantry Crane Refurbishment	Sustaining	Definition	F2024	5 - 4	Mica Facility Asset Plan
G000001	Alouette - Environmental Flow Discharge Upgrade and LLO Sealing	Sustaining	Identification	TBD	TBD	Alouette Facility Asset Plan
G000011	Alouette Improve Headworks & Surge Tower Seismic Stability	Sustaining	Identification	TBD	TBD	Alouette Facility Asset Plan
G000042	Ash River Extend Life of Steel Penstock	Sustaining	Identification	TBD	TBD	Ash River Facility Asset Plan; Generation Asset Management Strategy - Penstock Recoating
G003467	Bridge River 1 - Improve Slope Drainage	Sustaining	Identification	TBD	TBD	Bridge River Facility Asset Plan
G000485	Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior	Sustaining	Identification	TBD	TBD	Bridge River Facility Asset Plan; Generation Asset Management Strategy - Penstock Recoating
G003133	GMS – Install Further Instrumentation for Monitoring Embankment Condition	Sustaining	Identification	TBD	TBD	G.M. Shrum Facility Asset Plan

IPID	Project	Type	Phase	Forecasted ISD	Authorized Amount[8] / Engineering Estimate[9] ($ million)	Name of Strategy, Plan or Study to which Project is Linked
G003723	Hugh Keenleyside - Fire Protection System Upgrade	Sustaining	Identification	TBD	TBD	Hugh Keenleyside Facility Asset Plan
G000556	Hugh Keenleyside - Spillway and Low Level Outlets Concrete Upgrade	Sustaining	Identification	TBD	TBD	Hugh Keenleyside Facility Asset Plan
G000459	Lajoie - Dam Improvements	Sustaining	Identification	TBD	TBD	La Joie Facility Asset Plan; Bridge River System Study
G003365	Mica - Discharge Facilities Seismic and Reliability Upgrades	Sustaining	Identification	TBD	TBD	Mica Facility Asset Plan
G000467	Terzaghi - Spillway Chute Access Improvement	Sustaining	Identification	TBD	TBD	Bridge River Facility Asset Plan
G003653	Various Sites - Reservoir Booms Replacement - F2020	Sustaining	Identification	TBD	TBD	
G003554	W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates	Sustaining	Identification	TBD	TBD	G.M. Shrum Facility Asset Plan
G004327	Bridge River 1 - Penstock Concrete Foundation Refurbishment	Sustaining	Future	TBD	TBD	Bridge River Facility Asset Plan
G000052	Cheakamus - Dam Improvements	Sustaining	Future	TBD	TBD	Cheakamus Facility Asset Plan

IPID	Project	Type	Phase	Forecasted ISD	Authorized Amount[8] / Engineering Estimate[9] ($ million)	Name of Strategy, Plan or Study to which Project is Linked
G000131	G.M. Shrum - Intake Operating Gate and Intake Maintenance Gate Refurbishment	Sustaining	Future	TBD	TBD	G.M. Shrum Facility Asset Plan
G003336	G.M. Shrum - Intake Operating Gate Hydraulic Upgrade	Sustaining	Future	TBD	TBD	G.M. Shrum Facility Asset Plan
G002183	Hugh Keenleyside - Cranes Upgrade	Sustaining	Future	TBD	TBD	Hugh Keenleyside Facility Asset Plan
G003811	Kootenay Canal - Canal Concrete Liner Joints Upgrade	Sustaining	Future	TBD	TBD	Kootenay Canal Facility Asset Plan
G003234	Lake Buntzen 1 - Penstock Interior Restoration	Sustaining	Future	TBD	TBD	Coquitlam-Buntzen System; Facility Asset Plan
G003131	Mica - Little Chief Inclinometers Installation	Sustaining	Future	TBD	TBD	Mica Facility Asset Plan
G004405	Ruskin - Left Abutment Slope Sinkhole Remediation	Sustaining	Future	TBD	TBD	
G000543	Seton - Canal Flow Control Structure Upgrade	Sustaining	Future	TBD	TBD	Seton Facility Asset Plan; Bridge River System Study
G000295	Sugar Lake - Dam Abutments Upgrade	Sustaining	Future	TBD	TBD	Shuswap Facility Asset Plan
G000470	Terzaghi - Dam Instrumentation Upgrade	Sustaining	Future	TBD	TBD	Bridge River Facility Asset Plan

IPID	Project	Type	Phase	Forecasted ISD	Authorized Amount[8] / Engineering Estimate[9] ($ million)	Name of Strategy, Plan or Study to which Project is Linked
G000468	Terzaghi - Low Level Discharge Reliability Improvement	Sustaining	Future	TBD	TBD	Bridge River Facility Asset Plan; Bridge River System Study
G004064	Various Sites - Probabilistic Seismic Hazard Model Update	Sustaining	Future	TBD	TBD	
G004172	Various Sites - Spillway Gate Standby Power Improvements	Sustaining	Future	TBD	TBD	

Table FF-2 Dam Safety Projects with Capital Expenditures Greater than $100 million after the Test Period

IPID	Project	Type	Phase	Forecasted ISD	Authorized Amount[8] / Engineering Estimate[9] ($ million)	Name of Strategy, Plan or Study to which Project is Linked
G000109	Bennett Dam - Embankment and Spillway Seismic Upgrade	Sustaining	Future	TBD	TBD	G.M. Shrum Facility Asset Plan
G000474	Bridge River - Intake Seismic Withstand Improvement	Sustaining	Future	TBD	TBD	Bridge River Facility Asset Plan; Bridge River System Study
G000548	Duncan Dam - Embankment Dam Improvement	Sustaining	Future	TBD	TBD	
G000217	Peace Canyon - Dam Seismic Upgrade	Sustaining	Future	TBD	TBD	Peace Canyon Facility Asset Plan

IPID	Project	Type	Phase	Forecasted ISD	Authorized Amount[8] / Engineering Estimate[9] ($ million)	Name of Strategy, Plan or Study to which Project is Linked
G000235	Puntledge - Comox Dam Upgrade	Sustaining	Future	TBD	TBD	Puntledge Facility Asset Plan
G000247	Revelstoke - Discharge Gate Systems Reliability Improvements	Sustaining	Future	TBD	TBD	Revelstoke Facility Asset Plan
G000523	Strathcona - Embankment Dam Seismic Upgrades	Sustaining	Future	TBD	TBD	Campbell River Systems Engineering Assessment; Strathcona Facility Asset Plan
G004140	Waneta - Spillway Gate Reliability	Sustaining	Future	TBD	TBD	

Table FF-3 Dam Safety Projects with Capital Expenditure Less than $100 million and Greater than $20 million after the Test Period

IPID	Project	Type	Phase	Forecasted ISD	Authorized Amount[8] / Engineering Estimate[9] ($ million)	Name of Strategy, Plan or Study to which Project is Linked
G000751	Bennett Dam - Spillway Gates Further E&M Improvements	Sustaining	Future	TBD	TBD	G.M. Shrum Facility Asset Plan
G003685	Bridge River 1 - U1 - U4 Penstock Inlet Valves Replacement	Sustaining	Future	TBD	TBD	Bridge River Facility Asset Plan
G000060	Cheakamus - Spillway Gate Reliability Improvement-Stage 2	Sustaining	Future	TBD	TBD	Cheakamus Facility Asset Plan

IPID	Project	Type	Phase	Forecasted ISD	Authorized Amount[8] / Engineering Estimate[9] ($ million)	Name of Strategy, Plan or Study to which Project is Linked
G000664	Hugh Keenleyside - Concrete Dam Seismic Stability Upgrade	Sustaining	Future	TBD	TBD	Hugh Keenleyside Facility Asset Plan
G000139	Jordan River - Diversion Dam Emergency Low Level Outlet and Low Level Outlet Refurbishment	Sustaining	Future	TBD	TBD	Jordan River Facility Asset Plan
G003739	Kootenay Canal - U1 - U4 Penstocks Interior and Scroll Cases Recoat	Sustaining	Future	TBD	TBD	Kootenay Canal Facility Asset Plan; Generation Asset Management Strategy - Penstock Recoating
G000167	Lake Buntzen 1 - Flood Discharge Capability Improvement	Sustaining	Future	TBD	TBD	Coquitlam-Buntzen System Facility Asset Plan
G000178	Mica - Little Chief Slope Seismic Stability Improvement	Sustaining	Future	TBD	TBD	Mica Facility Asset Plan
G000752	Peace Canyon - Spillway Gates Further E&M Improvements	Sustaining	Future	TBD	TBD	Peace Canyon Facility Asset Plan
G000798	Peace Canyon - Spillway Gates Reliability Improvements	Sustaining	Future	TBD	TBD	Peace Canyon Facility Asset Plan
G003238	Seton - Canal Refurbishment	Sustaining	Future	TBD	TBD	Seton Facility Asset Plan; Bridge River System Study
G000427	Seven Mile - Discharge Gate Systems Reliability Improvement	Sustaining	Future	TBD	TBD	Seven Mile Facility Asset Plan

IPID	Project	Type	Phase	Forecasted ISD	Authorized Amount[8] / Engineering Estimate[9] ($ million)	Name of Strategy, Plan or Study to which Project is Linked
G003970	Strathcona - Powerhouse and Conduit Decommissioning	Sustaining	Future	TBD	TBD	Campbell River Systems Engineering Assessment; Strathcona Facility Asset Plan
G000330	Wahleach - Foundation Seepage Control Upgrade	Sustaining	Future	TBD	TBD	Wahleach Facility Asset Plan
G004141	Waneta - Dam Stability Improvement	Sustaining	Future	TBD	TBD	

Table FF-4 Dam Safety Projects with Capital Expenditure Less than $20 million and Greater than $5 million after the Test Period

IPID	Project	Type	Phase	Forecasted ISD	Authorized Amount[8] / Engineering Estimate[9] ($ million)	Name of Strategy, Plan or Study to which Project is Linked
G000053	Cheakamus - Penstock Pedestals and Slope Improvements	Sustaining	Future	TBD	TBD	Cheakamus Facility Asset Plan
G003578	Cheakamus - Penstock Rupture Detection Installation	Sustaining	Future	TBD	TBD	Cheakamus Facility Asset Plan
G000078	Clowhom - Penstock Interior Recoat	Sustaining	Future	TBD	TBD	
G003569	Duncan Dam - Discharge Systems Reliability Upgrade-Stage 2	Sustaining	Future	TBD	TBD	

IPID	Project	Type	Phase	Forecasted ISD	Authorized Amount[8] / Engineering Estimate[9] ($ million)	Name of Strategy, Plan or Study to which Project is Linked
G000130	G.M. Shrum - Water Passage Refurbishment - Phase I	Sustaining	Future	TBD	TBD	G.M. Shrum Facility Asset Plan
G000152	Jordan River - Bear Creek Spillway Upgrade	Sustaining	Future	TBD	TBD	Jordan River Facility Asset Plan
G003172	Kootenay Canal - U1 - U4 Intake Operating Gates Refurbishment	Sustaining	Future	TBD	TBD	Kootenay Canal Facility Asset Plan
G000163	Lake Buntzen 1 - Coquitlam Tunnel Inlet Portal Seismic Stability Improvement	Sustaining	Future	TBD	TBD	Coquitlam-Buntzen System Facility Asset Plan
G000179	Mica - Dutchman's Ridge Slope Stability Improvement	Sustaining	Future	TBD	TBD	Mica Facility Asset Plan
G000791	Mica - U1 - U6 Water Passage Coatings Restoration	Sustaining	Future	TBD	TBD	Mica Facility Asset Plan; Generation Asset Management Strategy - Penstock Recoating
G000228	Peace Canyon - U1 - U4 Penstock External Refurbishment	Sustaining	Future	TBD	TBD	Peace Canyon Facility Asset Plan; Generation Asset Management Strategy - Penstock Recoating
G000237	Puntledge - Puntledge Dam Structure Upgrade	Sustaining	Future	TBD	TBD	Puntledge Facility Asset Plan
G000249	Revelstoke - Downie Slide Slope Drainage Improvement	Sustaining	Future	TBD	TBD	Revelstoke Facility Asset Plan
G000542	Seton - Aqueduct Seismic Withstand Upgrade	Sustaining	Future	TBD	TBD	Seton Facility Asset Plan; Bridge River System Study

IPID	Project	Type	Phase	Forecasted ISD	Authorized Amount[8] / Engineering Estimate[9] ($ million)	Name of Strategy, Plan or Study to which Project is Linked
G002535	Seven Mile - Intake Gantry Crane Upgrade	Sustaining	Future	TBD	TBD	Seven Mile Facility Asset Plan
G000830	Seven Mile - U1 - U3 Intake Operating Gates Refurbishment	Sustaining	Future	TBD	TBD	Seven Mile Facility Asset Plan
G001045	Terzaghi - Dam Upstream Cut-off Upgrade	Sustaining	Future	TBD	TBD	Bridge River Facility Asset Plan; Bridge River System Study
G003634	Terzaghi - Downstream Infill Berm Construction	Sustaining	Future	TBD	TBD	Bridge River Facility Asset Plan; Bridge River System Study
G000338	Wahleach - Intake Tower / Gates Seismic Upgrade	Sustaining	Future	TBD	TBD	Wahleach Facility Asset Plan
G000361	Walter Hardman - Through Dam Conduits Replacement / Refurbishment	Sustaining	Future	TBD	TBD	
G004143	Waneta - Intake Gates	Sustaining	Future	TBD	TBD	
G000344	Whatshan - Seepage Control Installation	Sustaining	Future	TBD	TBD	Whatshan Facility Asset Plan
G000346	Whatshan - Tunnel Lining Upgrade	Sustaining	Future	TBD	TBD	Whatshan Facility Asset Plan

BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

Appendix GG

Greenhouse Gas Reduction Regulation Annual Report

Chris Sandve
Chief Regulatory Officer
Phone: 604-623-3918
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

June 30, 2021

GHG Reduction (Clean Energy) Regulation Reporting
Director, Communities and Transportation
Electricity and Alternative Energy Division
Ministry of Energy, Mines and Low Carbon Innovation
Email: GGRRReporting@gov.bc.ca

British Columbia Utilities Commission
GHG Reduction (Clean Energy) Regulation Reporting

Email: commission.secretary@bcuc.com

RE: Ministry of Energy, Mines and Low Carbon Innovation (MEMLCI or Ministry)
British Columbia Hydro and Power Authority (BC Hydro)
Greenhouse Gas Reduction (Clean Energy) Regulation Reporting Fiscal 2021 Annual Report

BC Hydro writes to submit the Business Information and Declaration (Attachment 1), the Fiscal 2021 Greenhouse Gas Reduction (Clean Energy) Regulation (**GGRR**) Annual Report (**Report**) (Attachment 2) and Low Carbon Electrification Program Results in an excel format (Attachment 3). The Report includes results for the period from April 1, 2020 to March 31, 2021 (**Fiscal 2021**) for BC Hydro's prescribed undertakings as defined in section 4 and section 5 of the GGRR.

Under section 18 of the *Clean Energy Act*, a public utility implementing prescribed undertakings defined in the GGRR must submit to the MEMLCI a report respecting the prescribed undertakings. Specifically, section 18(5) states that "a report to be submitted under section (4) must include the information the minister specifies and be submitted in the form and by the time the minister specifies."

On April 15, 2021, BC Hydro received from the MEMLCI an updated reporting template for the period from April 1, 2020 to March 31, 2021 for prescribed undertakings under the GGRR. This report contains information that reflects this updated template.

BC Hydro is providing the un-redacted Report to the Ministry and BCUC in confidence. A public version of the Report is being filed under separate cover redacting customer-specific information or information that is commercially sensitive to BC Hydro or customers. Confidential information is not to be released publicly without prior consent of BC Hydro and/or the customer.

June 30, 2021
GHG Reduction (Clean Energy) Regulation Reporting
Director, Communities and Transportation
Electricity and Alternative Energy Division
Ministry of Energy, Mines and Low Carbon Innovation

British Columbia Utilities Commission
GHG Reduction (Clean Energy)
Regulation Reporting

For further information, please contact the undersigned.

Yours sincerely,

Chris Sandve
Chief Regulatory Officer

st/rh

Enclosures

Greenhouse Gas Reduction (Clean Energy) Regulation Reporting

Attachment 1

Business Information and Declaration

Business Information and Declaration

Full Legal and Operating Name	Address Including Postal Code and Email	Telephone
British Columbia Hydro and Power Authority	333 Dunsmuir Street, Vancouver BC V6B 5R3	604-623-3726
Reporting Period:	April 1, 2020 to March 31, 2021 (Fiscal 2021)	
I understand that the information in this report is collected for the purposes of administering the Greenhouse Gas Reduction (Clean Energy) Regulation under the authority of the *Clean Energy Act* and section 26 of the *Freedom of Information and Protection of Privacy Act*. I certify that records evidencing each matter reported under the Greenhouse Gas Reduction (Clean Energy) Regulation (the Regulation) Reporting Requirements are available on request. I certify that a record evidencing my authority to submit this report on behalf of the public utility is available on request. I certify that the information in this report is true and complete to the best of my knowledge and I understand that I may be required to provide to the Ministry of Energy, Mines and Low Carbon Innovation or the Commission records evidencing the truth of that information.		
Signature of Authorized Signing Authority	Name and Title of Authorized Signing Authority (please print)	Date Signed YYYY/MM/DD
	Chris Sandve Chief Regulatory Officer	June 30, 2021

Greenhouse Gas Reduction (Clean Energy) Regulation Reporting

Attachment 2

Fiscal 2021 Annual Report No. 4
April 2020 to March 2021

PUBLIC

Table of Contents

List of Figures

List of Tables

1 Executive Summary

This is BC Hydro's fourth annual report regarding its activities that are "prescribed undertakings" as defined in the Greenhouse Gas Reduction (Clean Energy) Regulation (**GGRR**) for the purposes of section 18 of the *Clean Energy Act* (**CEA**). It is provided in accordance with the April 2021 “British Columbia Greenhouse Gas Reduction (Clean Energy) Regulation Reporting Requirements” (**Reporting Requirements**) provided to BC Hydro by the Ministry of Energy, Mines and Low Carbon Innovation.

This report covers the annual period from April 1, 2020 to March 31, 2021 (**Fiscal 2021 or Reporting Period**) and BC Hydro’s prescribed undertakings in three main classes:

(i) Low Carbon Electrification (**LCE**) activities under section 4(3)(a), (b), (c), and (d) of the GGRR (collectively referred to as **LCE Programs**);

(ii) LCE Infrastructure projects under section 4(2) and 4(3)(e) of the GGRR; and

(iii) Electric vehicle (**EV**) charging stations under section 5 of the GGRR.

The expenditure for the LCE Programs in fiscal 2021 is approximately $4.1 million, which covers the following undertakings:

- BC Hydro provided supporting resources[1] for nine new LCE studies and four new LCE incentive projects that are prescribed undertakings under section 4(3)(a) of the GGRR, further described in section 4.2 below;

[1] Supporting resources can include: funding provided by BC Hydro to enable studies, research, pilots, public awareness campaigns, projects, and enabling the development of standards.

- BC Hydro carried out public awareness campaign activities related to the EV charger 'Top-up' promotion from the previous fiscal year. These are prescribed undertakings under section 4(3)(a) of the GGRR; and
- BC Hydro provided supporting resources to enable the development of standards respecting technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions. These projects are undertakings prescribed under section 4(3)(d) of the GGRR.

BC Hydro also made significant progress on the Peace Region Electricity Supply (**PRES**) Project, which is a LCE Infrastructure Project undertaking under section 4(2) of the GGRR. In fiscal 2021, actual expenditure on the PRES Project was $53.3 million, with a cumulative cost of $206.2 million as at the end of fiscal 2021. It is premature to report any avoided greenhouse gas emissions for the PRES Project as it is not yet in-service. Total expenditures of $1.4 million were incurred in fiscal 2021 with respect to a [redacted] generation agreement BC Hydro entered into with [redacted] (hereinafter referred to as **Company X**) to ensure the provision of reliable electricity service from the transmission system [redacted]. This is also an LCE Infrastructure Project undertaking under section 4(2) of the GGRR.

During the Reporting Period, BC Hydro also constructed and operated EV fast charging stations which are prescribed undertakings under section 5 of the GGRR by adding five new eligible charging sites to its network of EV fast charging stations. Four of these sites were constructed with two fast charging stations each, and the fifth site was constructed with a single fast charging station. In addition, 10 existing eligible charging sites with a single fast charging station were expanded with an additional fast charging station. At the end of the Reporting Period, there were 97 eligible charging stations at 71 eligible charging sites in BC Hydro's fast charging network.

2 The GGRR and Cost Recovery

Section 18(1) of the CEA empowers the Lieutenant Governor in Council to prescribe, by regulation, classes of undertakings for the purpose of reducing greenhouse gas (**GHG**) emissions. Public utilities that choose to engage in undertakings that are within one or more prescribed class of undertaking are assured of being able to recover the costs of the undertaking in their rates, and may not be prevented by the BCUC from engaging in the undertaking.

The GGRR was first issued in 2012, and amended in 2017 by adding section 4 to the GGRR to include eight new classes of electrification undertakings and in 2020 by adding section 5 to the GGRR to include certain EV fast charging stations. Together, CEA section 18 and the GGRR provide one of the statutory pillars of the Province's GHG emission reduction policy.

One of the legal consequences of the public utility program or project being a "prescribed undertaking" is that the public utility is entitled to recover the costs of the program or project in its rates. That legal consequence is meaningful only if the costs associated with particular programs and projects that are prescribed undertakings can be identified, and thus are accounted for, by the public utility. Accordingly, the prescribed undertakings described in this fiscal 2021 GGRR Annual Report are those programs and projects with recorded costs in fiscal 2021.[2]

Pursuant to BCUC Order G-187-21, operating costs, depreciation, and cost of energy amounts related to the deployment and operation of BC Hydro's eligible EV fast charging stations and incurred during fiscal 2021 are deferred to the Electric Vehicle Costs Regulatory Account. As part of its fiscal 2023 to 2025 Revenue

[2] BC Hydro notes that the costs it incurs with regard to its LCE programs that are prescribed undertakings are all deferred to the DSM Regulatory Account, pursuant to Order in Council No. 100, issued March 1, 2017. Generally, the costs BC Hydro incurs in regard to its LCE Infrastructure Projects are capitalized.

Requirements Application, BC Hydro will apply for a recovery mechanism for this account.

3 State of the Market and Program Planning

3.1 Background

In December 2018, the Province launched the CleanBC Plan, which set out a pathway to enable the Province to meet its 2030 GHG emission targets. The CleanBC Plan calls for BC Hydro to continue to make investments in our transmission system to make it easier for large industrial operations to access clean electricity.

The February 2019 Minister's Mandate Letter to BC Hydro included an expectation for BC Hydro to continue to provide leadership in advancing the Province's climate action strategies, including through electrification, fuel switching, and energy efficiency initiatives in the built environment, transportation, oil and gas, and other sectors.

In July 2019, the Terms of Reference for Phase 2 of the Comprehensive Review (**Phase 2 Review**) were released by the Province. The objective of the Phase 2 Review is to develop recommendations that will strategically position BC Hydro for long-term success, while meeting the Province's climate goals, keeping rates affordable for British Columbians, furthering reconciliation with Indigenous Nations, and supporting quality economic development. The actions taken as part of the Phase 2 Review will support the Province's CleanBC plan, including to expand the electrification of our growing economy over the coming decades.

3.2 State of the Market Discussion

This section presents an overview of the LCE market with respect to BC Hydro's activities in fiscal 2021. Detailed information on the LCE Programs, LCE

Infrastructure Projects and EV fast charging stations is set out in section 4, section 5, and section 6 respectively below.

Beginning in fiscal 2018, BC Hydro moved forward with eight projects, referred to as Initial LCE Projects, to assess and support immediate low carbon electrification opportunities among our customers. These projects are within one (or more) class of undertakings defined in subsections 4(3)(a) and 4(3)(c). These Initial LCE Projects also:

- Helped us gain a greater understanding of the technology, market, and barriers that customers and BC Hydro would face when developing low carbon electrification options; and
- Provided BC Hydro with the ability to act early and capture time sensitive opportunities that could help inform the development of a broader low carbon electrification plan.

The Initial LCE Projects introduced in the GGRR Annual Report filed in July 2018 have been updated in subsequent reports as the expenditures were incurred. They are also included in Table 5 within this report.

In fiscal 2019, BC Hydro developed and advanced a multi-year BC Hydro funded LCE program that was designed to work in coordination with the Province's programs and is generally referred to as the BC Hydro LCE Program. The BC Hydro LCE Program is further described in section 4.

BC Hydro is forecast to be in an energy surplus position for an extended period of time. During this surplus period, the LCE-driven incremental electricity sales will increase BC Hydro's revenues and can make rates lower than they otherwise would have been to the extent there is a positive differential between domestic electricity rates and forecast export prices. These incremental electricity sales are also expected to reduce GHG emissions relative to what they otherwise would have been. .

Pursuant to the Reporting Requirements, a report by a Fairness Advisor must be provided on the competitiveness of any call process held during the Reporting Period. Consistent with our DSM process, opportunities for LCE Programs are solicited broadly through BC Hydro’s customer and community-facing employees and our existing commercial and industrial energy manager networks. In fiscal 2021, BC Hydro did not hold any call processes in regard to its LCE Programs or its LCE Infrastructure Projects. Therefore, no Fairness Advisor report is required.

BC Hydro issued tenders for construction services and equipment purchases for the installation of fast charging stations in fiscal 2021. The tenders followed standard procurement processes at BC Hydro, using bidding platforms such as BC Bid.

3.3 Province of B.C. Programs

In fiscal 2019, BC Hydro became responsible for delivering the CleanBC Better Buildings program (initially called EfficiencyBC) on behalf of the Province. The CleanBC Better Buildings is a program funded by provincial and federal governments that provides financial incentives to help households and businesses save energy and reduce GHG emissions by switching to high efficiency heating equipment and making building envelope improvements. BC Hydro is delivering the component of the CleanBC Better Buildings program that helps customers switch from fossil fuels to clean electricity.

In fiscal 2020, BC Hydro became responsible for delivering the CleanBC ‘Go Electric BC’ EV charger rebate program. The program provides rebates toward the cost of the purchase and installation of eligible level 2 EV charging equipment and supports multi-unit residential buildings (**MURB**) and workplaces seeking solutions for their EV charging needs. The CleanBC program influences what programs BC Hydro funds as it seeks to align with and complement the programs and projects funded by the Province through the CleanBC program. BC Hydro's programs that complement the CleanBC programs are discussed in section 4 below.

In fiscal 2021, the Province launched three new CleanBC programs. The CleanBC Indigenous Community Energy Coaching program provides free energy coaching services to support Indigenous communities wanting to take advantage of the CleanBC Indigenous Community Heat Pump Incentive and related energy efficiency offers. The CleanBC Better Homes New Construction program provides rebates for the construction of new, high-performance, electric homes. The CleanBC Commercial Express Program provides support to building owners and operators who wish to reduce greenhouse gas (**GHG**) emissions in their existing commercial buildings. The program targets simple, smaller electrification opportunities across commercial and institutional buildings. These programs are funded by the Province, and BC Hydro administers these programs on behalf of the Province.

3.4 Electric Vehicle Fast Charging Stations

At the beginning of fiscal 2021, BC Hydro had 81 fast charging stations in operation across the province, including three that were decommissioned during the fiscal year. At the end of fiscal 2021, BC Hydro had 97 eligible fast charging stations in operation at 71 sites. During fiscal 2021, BC Hydro continued to build out its EV fast charging network, by deploying 19 EV eligible fast charging stations. Nine of these fast charging stations were at five new sites (i.e., two charging stations at four sites, and a single charging station at the remaining new site), and 10 fast charging stations were added to existing sites that have single EV fast charging stations.

Throughout fiscal 2021, BC Hydro continued to work with the Ministry of Energy and Low Carbon Innovation (M**EMLI**), the Ministry of Transportation and Infrastructure (**MOTI**), and FortisBC to plan an efficient deployment of EV fast charging stations and to meet the provincial objective of a province-wide EV fast charging network which will enable inter-city travel with an EV.

All of BC Hydro's EV fast charging stations are all in compliance with requirements of section 5 of the GGRR.

4 LCE Programs

4.1 Overview

There are eight new classes of electrification undertaking prescribed by section 4 of the GGRR, which can be divided into two broad categories: (i) those that are program based, similar to BC Hydro's demand-side management programs;[3] and (ii) those that are infrastructure based.[4] BC Hydro refers to all the prescribed undertakings it carries out under section 4 of the GGRR as LCE activities, and further refers to its undertakings that fall within one of the classes in the former category as LCE Programs, and to its undertakings that fall within one of the classes in the latter category as LCE Infrastructure Projects. This nomenclature corresponds to the "Electrification Programs" referred to in subsection 6.7 of the GGRR Reporting Requirements, and "Transmission, Distribution and Generation" referred to in subsection 6.8 of the GGRR Reporting Requirements, respectively.

In fiscal 2021, BC Hydro spent approximately $4.1 million on its LCE Programs, including expenditures for the Initial LCE Projects and the BC Hydro LCE Program. The expenditures supported four new projects, nine new studies, and public awareness campaign activities, all undertaken in accordance with section 4(3)(a) and 4(3)(b) of the GGRR. BC Hydro also incurred expenditures to enable the

3 Being the classes of undertaking prescribed by subsections 4(3)(a)(i), 4(3)(a)(ii), 4(3)(b)(i), 4(3)(b)(ii), 4(3)(c) and 4(3)(d) of the GGRR. Undertakings can be both projects or programs. For simplicity, BC Hydro may refer to projects under these sections as programs as well or use projects/program interchangeably.

4 Being the classes of undertaking prescribed by subsections 4(2) and 4(3)(e) of the GGRR.

development of standards under section 4(3)(d) of the GGRR. These LCE undertakings are discussed in section 4.2.

In fiscal 2021, BC Hydro made new funding commitments of approximately $0.5 million, but there are no expenditures for the studies and projects associated with those commitments in the financial reporting for fiscal 2021. As noted in previous Annual Reports, funding commitments that did not result in expenditures in fiscal 2021 are not included in this Reporting Period, but will be included in a future GGRR report for the fiscal year when the expenditures are incurred.

As discussed above, since fiscal 2019, BC Hydro has been delivering the CleanBC Better Buildings program on behalf of the Province. In fiscal 2019, to complement the Province's program, BC Hydro developed and advanced a multi-year BC Hydro funded LCE Program to reach customers and to enable opportunities not covered by GHG emissions reduction programs funded by the Province or the federal government.[5] BC Hydro approved expenditures of $16.6 million for this multi-year program, focusing on opportunities in industrial process, transportation, and new construction.

In fiscal 2020, the Province, working in co-ordination with BC Hydro, decided to add a CleanBC program for new construction. The introduction of this new program prompted BC Hydro to re-consider the funding originally included within the multi-year BC Hydro LCE Program. BC Hydro decided to apply funds originally intended for supporting new construction opportunities to supporting additional energy management study and implementation opportunities for industrial and large commercial customers.

In fiscal 2021, as part of BC Hydro's multi-year program, BC Hydro undertook activities as prescribed undertakings falling under section 4(3)(a),section 4(3)(b),

5 This multi-year program is also referred to as the "BC Hydro LCE Program" to distinguish it from the programs funded by the Province.

and section 4(3)(d) of the GGRR. These undertakings are discussed in section 4.2 below. Also in fiscal 2021, BC Hydro began the development of a broad electrification plan which will describe BC Hydro's actions supporting customer fuel switching. The plan will be provided in BC Hydro's Fiscal 2023 – Fiscal 2025 Revenue Requirements Application.

4.2 Fiscal 2021 LCE Programs

The projects and activities within the LCE Programs (i.e., classes of undertaking prescribed by subsections 4(3)(a)(i), 4(3)(a)(ii), 4(3)(b)(i), 4(3)(b)(ii), 4(3)(c) and 4(3)(d) of the GGRR) that incurred expenditures in fiscal 2021 are listed below. Table 5 includes the LCE Programs results for fiscal 2021, and Figure 1 and Figure 2 show LCE Programs activities and expenditures by geographic distribution and sector distribution, respectively.

Consistent with the Reporting Requirements, two larger upstream natural gas projects have been described at a project level, while the remaining fiscal 2021 activities are components of the BC Hydro LCE Program, and have been aggregated and summarized at the program level:

(iv) [redacted] (**Project 3** in Table 5): This project is interconnected to BC Hydro transmission line [redacted] in Northeastern B.C. The supporting funding from BC Hydro is to assist the customer in the acquisition, installation, and use of equipment that will use BC Hydro's electricity instead of natural gas to power natural gas extraction, processing and production operations, and it is an undertaking within the class of prescribed undertakings set out in section 4(3)(a) of the GGRR. There are multiple project phases. The first two phases achieved Facility Commercial Operation Date (**Facility COD**)[6] in fiscal 2019 and fiscal 2020, respectively, pursuant to the terms of the LCE

[6] Under the Incentive Agreement, Facility COD is required before an incentive fund payment can be made to the customer.

Incentive Agreement for the project. A third phase of this project was originally planned for fiscal 2021 but the expected completion date for the phase has shifted to fiscal 2022. Further project phases are expected to achieve Facility COD in subsequent fiscal years;

(v) [redacted] (**Project 4** in Table 5): BC Hydro has an LCE Incentive Agreement for the [redacted] site. This project is interconnected to BC Hydro transmission line [redacted] in Northeastern B.C. There are multiple project phases. Similar to Project 3, this project is an undertaking within the class of prescribed undertakings set out in section 4(3)(a) of the GGRR. Project 4 was energized in fiscal 2019 and the first two phases achieved Facility COD in fiscal 2020 in accordance with the LCE Incentive Agreement. A third phase was originally planned for completion in fiscal 2021, but is currently expected to complete in fiscal 2022; and

(vi) The BC Hydro LCE Program: Table 1 outlines the components of the BC Hydro LCE Program and the relevant subsections of the GGRR.

Table 1 Components of the BC Hydro LCE Program

Components	GGRR Subsection
Energy Management Studies and Incentives	4(3)(a), 4(3)(b)
Public Awareness Campaigns	4(3)(a), 4(3)(b)
Research and Pilots	4(3)(c)
Standards Enabler	4(3)(d)
Education & Training	4(3)(b)

An overview of activities in fiscal 2021 for each of the components of the BC Hydro LCE Program is provided below.

Energy Management Studies and Incentives: BC Hydro provided two types of funding related to energy management. First, BC Hydro provided funding to customers for studies and assessments which would assist customers, or those who may become customers, to identify and develop project opportunities involving the acquisition, installation, or use of equipment that uses electricity instead of other sources of energy that produce more greenhouse gas emissions. Table 2 below provides descriptions of the studies that were funded. Second, BC Hydro provided incentive funding to projects of customers, or those who may become customers (also referred to incentive projects), which would assist in the acquisition, installation, or use of equipment that uses electricity instead of other sources of energy that produce more greenhouse gas emissions. Table 3 below provides descriptions of the incentive projects that were funded. In fiscal 2021, expenditures for Energy Management Studies and Incentives are reflected in the BC Hydro LCE Program (row 10 in Table 5).

Table 2 Energy Management Studies

Sector	Description	Location	Studies Completed	GGRR Sub-section
Built Environment	Two studies for the built environment sector were completed in fiscal 2021. One study investigated the low carbon electrification options for space heating of an office building. The other study examined low carbon electrification options for a district energy system of a post-secondary institution. The study examined both retrofit opportunities and future new construction.	Lower Mainland, Southern Interior	2	4(3)(a)

Sector	Description	Location	Studies Completed	GGRR Sub-section
Industrial Process	Six studies for the industrial process sector were completed in fiscal 2021. One study examined a low carbon electrification option for a portion of the route used to transport material for a mine operation in the Southern Interior. A second study in the Southern Interior investigated the use of a low carbon electrification option in place of fossil fuels for the heating system of the ventilation shaft of a mine operation. Two studies of low carbon electrification options for natural gas processing were completed for two different sites in the Northern Interior. A study was completed for a mining operation in the Northern Interior. It examined the used of a low carbon electrification option in place of diesel power for tunneling operations. A study investigating low carbon electrification options for steam powered equipment was completed for a facility in the Vancouver Island / Sunshine Coast region.	Southern Interior, Northern Interior, Vancouver Island / Sunshine Coast	6	4(3)(a)
Transportation	One study was completed in the transportation sector in fiscal 2021. This study examined terminal infrastructure modification and charging systems to support electrification of marine vessels.	Vancouver Island / Sunshine Coast	1	4(3)(a)

Table 3 Incentive Projects

Sector	Description	Location	Incentive Projects Completed	GGRR Sub-section
Built Environment	One incentive project was completed in fiscal 2021. A facility was switched from diesel power to electric power by adding their own substation to connect to the BC Hydro transmission system.	Vancouver Island / Sunshine Coast	1	4(3)(a)

Industrial Process	Three incentive projects in the Industrial Process sector completed in fiscal 2021. A mining operation built a new power line to power remotely located equipment and switch from diesel power to electric. A mining operation replaced a diesel powered hauling equipment with battery electric. A mine built a new power line to a remotely located equipment which enabled switching from diesel power to electric.	Northern Interior, Southern Interior	3	4(3)(a)

Public Awareness Campaign: This includes public awareness activities carried out by BC Hydro to educate customers with regard to energy use and greenhouse gas emissions. Public awareness campaign expenditures in fiscal 2021 represent the trailing costs of the EV charger 'Top-up' promotion from the previous fiscal year. The public awareness campaign program and 'Go Electric BC' EV charger rebate 'Top-up' promotional program are undertakings within the class of prescribed undertakings set out in section 4(3)(a) of the GGRR. The fiscal 2021 expenditures for this public awareness campaign are included in the BC Hydro LCE Program (row 10 in Table 5).

Standards Enabler: BC Hydro worked with standards making bodies such as various levels of government, who are responsible for land use, building codes, product and equipment standards, policies, bylaws, and community plans, to advance standards for technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions, or standards for technologies that affect the use of electricity by other technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions. BC Hydro's activities in this regard target the transportation and building sectors.

BC Hydro undertook the following work with regard to transportation electrification:

- BC Hydro provided support for the implementation of EV ready bylaws and for the development of an updated best practice guide on EV ready requirements for both residential and non-residential new buildings. Best practices were shared widely through a local government EV peer network;

- BC Hydro supported a local government-led study that investigates the role that local governments can play in accelerating medium and heavy-duty zero emissions vehicle adoption; and
- BC Hydro is piloting a program to advance transportation electrification within local government transportation departments by developing transportation network design requirements, land use plans, policy and bylaws, permitting, and building codes.

BC Hydro undertook the following work with regard to building electrification:

- BC Hydro, the Province and the City of Vancouver supported a study on a Building Electrification Road Map (BERM) for BC, based on consultation with over 150 stakeholders. The BERM's purpose is to provide recommendations to key building sector stakeholders on the necessary steps to achieve a smooth market transformation that achieves government emission reduction goals;
- Through a local government working group and an industry and Provincially led advisory committee, BC Hydro provided supporting resources for the development of a Low Carbon Policy Toolkit. The Toolkit provides practical guidance and recommendations on policies, guidelines and bylaws that any local government can adopt to support building electrification; and
- Some local governments are taking steps to encourage electrification of new construction through structuring their Energy Step Code requirements. BC Hydro supported local governments in the development of a best practice bulletin, which summarizes a standardized approach and supports policy consistency.

Standards Enabler undertaking expenditures fall under section 4(3)(d) of the GGRR. In fiscal 2021, expenditures for Standards Enabler undertakings are reflected in the BC Hydro LCE Program (row 12 in Table 5).

4.3 Methodology and Verification Methods

Depending on individual projects or programs within the LCE Programs, there can be up to four distinct activities that BC Hydro may use to review and verify estimates of incremental electrical load and emission reductions arising from electrification. These are: (i) technical review; (ii) site inspection; (iii) measurement and verification; and (iv) evaluation. Results from each area may be used in project or program management to ensure that BC Hydro receives the expected benefits. BC Hydro is selective in the use of these processes, and focuses its efforts where warranted to improve the accuracy of estimates and reduce exposure to risk. This approach mirrors BC Hydro's current approach to demand-side management electricity savings and provides estimates for both additional electricity demand and greenhouse-gas emission reductions.

The GHG emission reduction estimates are developed as part of the technical review for each project or program application and may be adjusted based on the outcome of site inspections and the electricity demand findings resulting from the measurement and verification activities.

The methodology BC Hydro has used to estimate GHG emission reductions involves developing engineering estimates of the amount of carbon-based fuel that will be offset by electricity and quantifying the associated GHG emission reductions using the 2017 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions. The calculation nets out the GHG emissions associated with BC Hydro's electricity, which are also quantified using the 2017 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions.

This estimate may differ from actual GHG emission reductions as determined by the customer specific to their unique electrification project(s). Where an actual value has been provided to BC Hydro by the customer, or reported by the customer to the government through an Industrial Emissions Report, BC Hydro will show the customer-reported value in Column H (i) of Table 5. BC Hydro may also conduct a technical review of baselines, calculations, and assumptions used to determine the GHG reductions in the Industrial Emissions Report. Any changes to the value reported in a previous reporting period will be reflected in the cumulative values in Column H (ii) of Table 5. The methodology used for typical electrical energy impact calculations for LCE projects is as follows:

- Total annual energy consumption = facility baseline electricity consumption + incremental LCE electricity consumption +/- baseline energy adjustments; and
- Total average monthly electrical demand = baseline average monthly electrical demand + incremental LCE average monthly electrical demand +/- baseline demand adjustments.

Baseline adjustments are determined based on any net baseline energy consumption impacts that may be a result of the LCE project.

Each of four LCE incentive projects described in Table 3 has gone through a technical review and has a site specific measurement and verification (**M&V**) plan for the estimated additional electricity consumption and average demand. M&V plans are included as part of the funding agreement between BC Hydro and the recipient. The respective methodology used for these four projects generally follow 'Option B, Retrofit Isolation: All Parameter Measurement', as set out in the International Performance Measurement & Verification Protocol (**IPMVP**) - Core Concepts October 2016 EVO 10000 - 1:2016.

4.4 Performance Metrics

Performance measurement for BC Hydro LCE programs and projects ultimately is reflected in decisions made by customers or those who may become customers to use electricity instead of other sources of energy that produce more greenhouse gas emissions.

Public awareness campaigns, energy management studies, research/pilot projects, education and training and providing funds to assist in the acquisition, installation or use of equipment that uses or affects the use of electricity are critical in enabling customers, or those who will become customers, to develop reasons and justifications to implement a fuel-switching project. Additionally, these activities provide key inputs into BC Hydro program development and design.

Performance of standards enabler undertakings considers whether the support may yield information to enable government efforts in the advancement of standards, policies, bylaws, and community plans for the electrification of certain sectors, such as new construction and retrofits within the built environment and transportation sectors.

Performance measured using the measurement and verification methodologies described in section 4.3, provides a view of electrical consumption, demand, and GHG emission reductions. Measurement and verification activities for the projects completed in fiscal 2021 are still underway.

A measurement and verification report was completed in fiscal 2021 for the Thompson Rivers University project, which was installed in fiscal 2019. The verified electricity consumption for the project is 1,129 MWh per year, which is about 41 per cent of initial review estimated energy consumption. The annual natural gas savings are estimated to be 4,838 GJ, with an associated GHG reduction of 229 tonnes CO2e per year. The lower than expected consumption was primarily due to a change in the design made after the initial BC Hydro review. The measurement and verification results have been incorporated in Table 5.

4.5 Cost-Effectiveness

Under section 4(4) of the GGRR, undertakings are in the class of undertakings prescribed by sections 4(3)(a) or 4(3)(b) of the GGRR only if they satisfy a cost-effectiveness test. That cost-effectiveness test is defined in section 4(1) of the GGRR and requires that each undertaking that is an undertaking within the class of undertakings prescribed by subsections 4(3)(a) or 4(3)(b) of the GGRR have a positive net present value (**NPV**), with the measure of a program's NPV being that of all of the programs that fall within the class of undertakings described in subsections 4(3)(a) and 4(3)(b) of the GGRR. The GGRR cost-effectiveness test is measured only at the time BC Hydro decides to carry out the program.

Table 5 shows the GGRR net present value (**NPV**) of the various LCE projects or programs prescribed under section 4(3)(a) and 4(3)(b) of the GGRR. The total GGRR NPV of these undertakings is $114 million which includes actual and committed expenditures and benefits from past, current, and future reporting periods. The GGRR NPV indicates that these undertakings are cost-effective.

4.6 Summary of Results

4.6.1 Explanation of Terms

Table 4 below includes a description of the information provided in Table 5 with regard to the LCE Programs.

Table 4 LCE Programs Results Table: Explanation of Terms

Column	Heading	Descriptions
A	GGRR	Applicable section of the GGRR.
B	Project / Program / Contract / Expenditure	Low-carbon electrification activities to encourage or enable the use of electricity in place of other sources of energy that produce more greenhouse gas emissions.

Column	Heading	Descriptions
$C_{(i)}$	Actual Expenditure ($ million)	Costs incurred at the end of the current reporting fiscal year.
$C_{(ii)}$	Cumulative: Actual Expenditures ($ million)	The sum of successive costs incurred as at the end of the reporting fiscal year.
D	Cost Effectiveness ($ million): NPV to 2030 (fiscal 2031)	The present value of the costs and benefits are determined using a discount rate equal to BC Hydro's weighted average cost of capital. The present value of the costs is subtracted from the present value of the benefits from the project start year to last year in the calculation period (fiscal 2031) to determine the net present value for the project.
E	Cost Effectiveness ($ million): GGRR NPV to 2030 (fiscal 2031)	The calculation of the GGRR NPV is based on costs and benefits as of fiscal 2018 as defined in the GGRR. Per that definition, benefits mean all revenues BC Hydro expects to earn as a result of implementing LCE programs falling under subsections 4(3)(a) or 4(3)(b), less revenues that would have been earned from the sale of that electricity to export markets. Costs mean all the costs BC Hydro expects to incur to implement LCE programs falling under subsections 4(3)(a) or 4(3)(b), including development and administration costs. For clarity, costs include historic and future cost, committed expenditures and benefits from past, current and future reporting periods.
$F_{(i)}$	Actual: Additional Energy Consumption (MWh/year)	The average annual additional energy consumption estimated to be delivered from the project in the current reporting fiscal period.
$F_{(ii)}$	Cumulative: Additional Energy Consumption (MWh/year)	The sum of the successive average annual additional energy consumption estimated to be delivered from the project as at the end of the reporting fiscal period.
$G_{(i)}$	Actual: Additional Capacity Demand (MW)	The total energy demand added.
$G_{(ii)}$	Cumulative: Additional Capacity Demand (MW)	The sum of the successive energy demand addition.
$H_{(i)}$	Actual: Estimated GHG Emission Reductions (tonnes CO_2e/year)	The average annual tonnes per year of carbon dioxide equivalent reductions from the project in the current reporting fiscal period.
$H_{(ii)}$	Cumulative: Estimated GHG Emission Reductions (tonnes CO_2e/year)	The sum of the successive additional average annual tonnes per year of carbon dioxide equivalent reductions from the project as at the end of the reporting fiscal period.

4.6.2 Results Table

Table 5 below summarizes information regarding the LCE Programs that are undertakings prescribed by sections 4(3)(a)(i), 4(3)(a)(ii), 4(3)(b)(i), 4(3)(b)(ii), 4(3)(c) and 4(3)(d) of the GGRR. The indications of "n/a" in Table 5 are due to: (1) the nature of the project, study, research or program, such that the requested information cannot be obtained; or (2) the project, study, or program are prescribed by sections 4(3)(c) and 4(3)(d) of the GGRR and the cost-effectiveness test does not apply. Attachment 3 provides an excel spreadsheet with annual expenditures, in total and by project, study, or program, as outlined in the GGRR Reporting Requirements.

Table 5 LCE Programs Results for Year Ending March 31, 2021

	A	B			C		D	E	F		G		H	
	GGRR	**Project / Program / Contract / Expenditure**	**Municipality / Location**	**Start Date[6]**	**Expenditure[2] ($ million)**		**Cost Effectiveness (F2018$ million)**		**Additional Energy Consumption[3] (MWh/year)**		**Additional Demand (MW)**		**Estimated GHG Emission Reductions (tonnes CO_2e/year)**	
					Actual F2021 (i)	**Cuml. F2018-F2021 (ii)**	**NPV to 2030 (Fiscal 2031)**	**GGRR NPV to 2030 (Fiscal 2031)**	**Actual F2021 (i)**	**Cuml. F2018-F2021 (ii)**	**Actual F2021 (i)**	**Cuml. F2018-F2021 (ii)**	**Actual F2021 (i)**	**Cuml. F2018-F2021 (ii)**
1	4(3)(c)	Vancouver Fraser Port Authority	Vancouver	Fiscal 2018	0.00	0.07	0.0	0.0	0	0	0.0	0.0	0	0
2	4(3)(c)	[redacted] (Project 1)[4]	[redacted]	Fiscal 2018	0.00	0.00	0.0	0.0	0	0	0.0	0.0	0	0
3	4(3)(c)	[redacted] (Project 2)[4]		Fiscal 2018	0.00	0.01	0.0	0.0	0	0	0.0	0.0	0	0
4	4(3)(c)	BC Hydro Program Staff Labour			0.00	0.12	0.0	0.0	0	0	0.0	0.0	0	0
5	4(3)(a)	[redacted] (Project 3)[5]	[redacted]	Fiscal 2018	0.16	7.93	64.3	64.3	0	130,305	0.0	17.5	0	77,911
6	4(3)(a)	[redacted] (Project 4)		Fiscal 2018	0.00	11.25	45.9	110.2	0	186,150	0.0	25.0	0	111,302
7	4(3)(a)	Thompson Rivers University[7]	Kamloops	Fiscal 2018	-0.07	0.21	0.3	110.5	-1,608	1,129	0.3	0.6	-333	229
8	4(3)(c)	Copper Mountain Mine	Princeton, Southern Interior	Fiscal 2018	0.00	0.07	0.0	110.5	0	0	0.0	0.0	0	0
9	4(3)(c)	Translink	Lower Mainland	Fiscal 2018	0.00	0.50	0.0	110.5	0	1,254	0.0	0.8	0	215
10	4(3)(a)(b)	BC Hydro LCE Program	Province-wide	Fiscal 2019	2.85	6.33	3.5	114.0	4,709	4,709	0.7	0.7	3,630	3,630
11	4(3)(c)	BC Hydro LCE Program[8]	Province-wide	Fiscal 2019	0.00	0.44	0.0	114.0	0	0	0.0	0.0	0	0
12	4(3)(d)	BC Hydro LCE Program	Province-wide	Fiscal 2019	1.18	1.44	0.0	114.0	0	0	0.0	0.0	0	0
		Total			**4.12**	**28.37**	**114.0**	**114.0**	**3,101**	**323,547**	**1.0**	**44.6**	**3,297**	**193,286**

1 LCE Programs shown in the table include both LCE Initial Projects (rows 1 to 9) and associated expenditure and the BC Hydro LCE Program (rows 10 to 12). LCE Initial Projects are reported individually. With the introduction of the BC Hydro LCE Program individual project expenditures have been aggregated.
2 Where a project/program has no actual or cumulative expenditures, but has an NPV, this means that the decision to go ahead with that project/program was made in this (or previous) Reporting Periods, but that the project/program is not expected to be implemented until a future year.
3 Values reported in column F represent the 'run rate' or annualized rate of additional energy consumption.
4. Project 1 and 2 were described in the fiscal 2018 Annual Report filed in July 2018.
5 Fiscal 2021 expenditures for Project 3 represent a missed accrual for a portion of the second phase of the project which completed in fiscal 2020.
6 The Start Date is the fiscal year that BC Hydro decided to proceed with the project or program.
7 The negative expenditure in fiscal 2021 represents an adjustment to the incentive amount and the negative energy consumption also represents an adjustment, following completion of the Measurement and Verification report.
8 A fleet electrification study was undertaken in fiscal 2021, but not put forward as a prescribed undertaking. The $68,000 expenditure for the study was expensed as an operating cost in fiscal 2021.

4.7 LCE Programs by Region and Sector

The GGRR Reporting Requirements also request graphical depictions of the distribution by region in the Province and the distribution by customer sector where possible. The requested graphical depictions are provided below. The sectors (built environment, industrial process, and transportation) shown in the chart below align with those reflected in the CleanBC plan and in the description in section 4.2 of this report.

For the purpose of showing LCE Program activities distributed by region and by sector we have used the term 'Project' to represent individual studies, research or pilot activities, or implementation projects where customers have acquired and installed equipment that uses electricity instead of other sources of energy that produce more GHG emissions as described in section 4.2. We did not include Public Awareness Campaigns in Figure 1 or Figure 2 as those activities were carried out Province-wide and targeted a single sector (transportation) and as such would not be meaningful in a graphical depiction.

Figure 1 below highlights that the highest number of projects are in the Southern Interior, while Figure 2 below highlights that most of the projects are in the industrial process sector.

Figure 1 Projects by Geographic Region

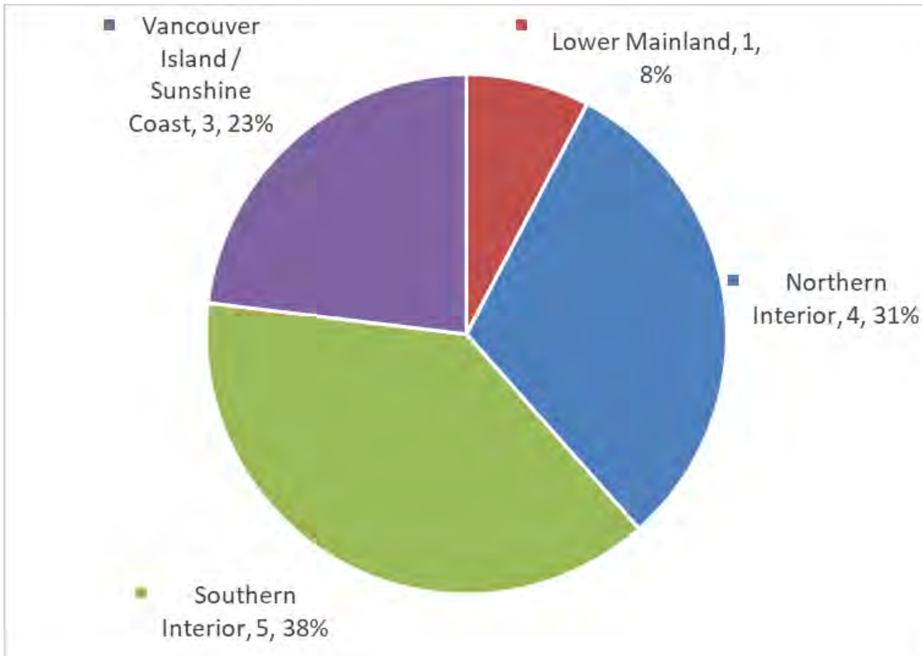
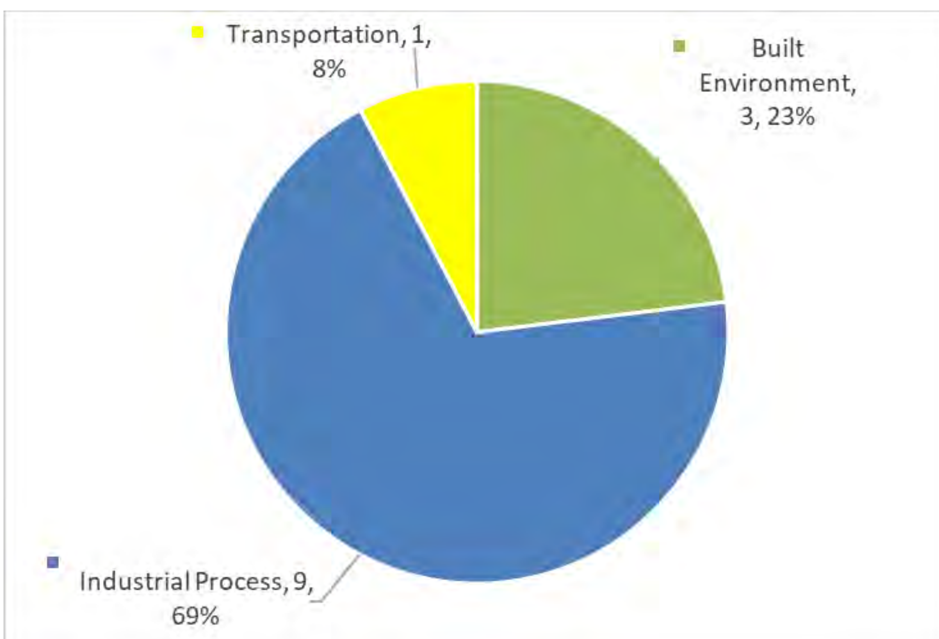


Figure 2 Projects by Sector



5 LCE Infrastructure Projects

5.1 Overview

In this section, we describe the LCE Infrastructure Projects (i.e., being projects within the classes of undertaking prescribed by subsections 4(2) or 4(3)(e) of the GGRR) and available evaluation results.

Northeast British Columbia is forecasted to experience a significant increase in natural gas production and processing capacity, primarily in the Montney region. In the absence of adequate electricity supply, much of this development will be powered by natural-gas fired production processes. Meanwhile, BC Hydro's transmission system in this region is constrained. Accordingly, BC Hydro will construct and operate new transmission and distribution facilities, and/or provide for [redacted] generation until such system upgrades are completed. These LCE Infrastructure Projects will enable the provision of reliable electricity service as a power supply alternative to carbon-based fuels, which will enable the reduction of existing GHG emissions or avoidance of future incremental GHG emissions.

5.2 Fiscal 2021 LCE Infrastructure Projects

In fiscal 2021, BC Hydro incurred expenditures of $54.7 million in regard to two LCE Infrastructure Projects. Expenditures incurred and recorded in future fiscal years will be included in the applicable future GGRR annual report.

5.2.1 Peace Region Electricity Supply (PRES) Project

The PRES Project was introduced in the fiscal 2018 GGRR Annual Report. As explained in the fiscal 2018 report, the PRES Project will enable natural gas producers and processors to electrify their existing and new operations, rather than self-supplying with natural gas. This includes natural gas producers and processors as defined in GGRR sections 4(2)(a)(i) and (ii). The PRES Project is expected to reduce GHG emissions in B.C. from any existing plant or from any prospective new plant that elects to take supply from BC Hydro rather than self-supply using natural gas.

The PRES Project was approved for implementation by BC Hydro's Board of Directors in June 2018. When BC Hydro's Board of Directors approved the PRES project, BC Hydro reasonably expected that the PRES project would have an in-service date no later than December 31, 2022. Therefore, the PRES Project is a prescribed undertaking pursuant to GGRR section 4(2). The PRES Project went into service in May 2021.

The PRES Project is currently in the Implementation Phase and has an estimated total cost of $285 million. As of the end of fiscal 2021, BC Hydro has incurred $206.2 million in total expenditures on developing the PRES Project, of which $53.3 million was incurred in fiscal 2021.

During fiscal 2021, BC Hydro completed construction and commissioning at the South Bank Substation 230 kV switchyard. BC Hydro also completed construction of the two new transmission lines and started reclamation, remediation and slope stabilization work at locations along the transmission corridor.

Since the project was just recently placed in-service, BC Hydro expects to report on performance metrics and environmental benefits of undertaking the PRES Project in the next reporting period.

5.2.2 [redacted] Generation Agreement

As reported in the fiscal 2018 GGRR Annual Report, BC Hydro entered into a Generation Agreement with Company X. The purpose of the Generation Agreement with Company X is to provide reliable electricity supply during periods of actual or anticipated system constraints. When Company X first interconnected to BC Hydro's transmission system, there was a known risk of area transmission system capacity constraints (thermal overload) on hot summer days. The Generation Agreement was a lower-cost and more efficient demand side solution to mitigate the risk of thermal overload until the PRES Project was in-service.

Under the Generation Agreement, BC Hydro treats Company X's generation as a firm dispatchable system resource, such that any self-generated electricity temporarily replaces electricity that would otherwise be provided from the BC Hydro transmission system. BC Hydro has the right to direct Company X to temporarily island its facilities in Northeast B.C. from the grid and self-supply them with electricity produced by Company X's on-site generating units. BC Hydro also has the right for economic dispatch of these generating units during the Agreement term.

BC Hydro terminated its right to direct Company X to temporarily island its Project 4 facility effective December 31, 2020, but maintained the right to direct Company X to temporarily island its Project 3 facility until August 31, 2021 (at which point the Generation Agreement will automatically expire, unless extended by BC Hydro). The August 2021 termination date is aligned to the original expected PRES in-service date of October 2021 and the end of summer 2021. At this time, BC Hydro does not plan to seek an Agreement extension.

The total forecast nominal value of the Generation Agreement is $12.0 million. Total expenditures incurred in fiscal 2021 with respect to this agreement are $1.4 million.

5.3 Quantitative Data – Methodology & Assumptions

BC Hydro has developed criteria to qualify customer loads for inclusion in its estimates for GHG emissions reduced or avoided due to the PRES Project.

The customer load to be included:

- Must be a new natural gas processing plant (including associated gas gathering and wellpad facilities) or existing plant converting to take grid service which takes, or commits to take, electricity service from BC Hydro in fiscal 2018 or later;

- Would have used natural gas for power supply in the absence of BC Hydro's commitment to construct and operate new facilities; and
- Will be served by the PRES Project once it is placed in-service.

These criteria include: (i) existing "brownfield" loads which fuel-switch from carbon-based fuel to grid electricity; and (ii) new "greenfield" loads that make the investment decision to take grid electricity as an alternative to carbon-based fuels for power supply.

BC Hydro notes that these criteria differ from the current British Columbia Greenhouse Gas Offset Protocol (*Fuel Switch Version 1.0, dated August 16, 2018*) which is specific to the replacement of existing gas-powered turbines with electrical grid power. Under the current protocol, GHG emission reductions would only arise where an existing customer facility fuel switches from a carbon-based fuel (such as natural gas) to low-carbon grid electricity and would not apply to any new plant that elects to be served with grid electricity in the first instance.

5.4 Performance Metrics

The GGRR performance metrics for the PRES Project are listed in Table 6 below.

Table 6 PRES Project: GGRR Performance Metrics

Type of Facility	Project(s)	Performance Metrics
Transmission & Distribution	PRES Project	New load served GHG emissions reduction
[redacted] Generation	[redacted] Generation Agreement	New load served Mitigation of system constraints GHG emissions reduction

A key purpose of the PRES Project is to enable a clean, reliable source of electrical power supply to existing and new natural gas processing operations. In the absence of the PRES Project, there would be no electricity grid service alternative. These plant operations would otherwise need to use natural gas (or other fossil fuels) for power supply. Since greenhouse gases are emitted when fossil fuels are burned to create power, the PRES Project will reduce GHG emissions in British Columbia for any existing plant that elects to take grid service rather than self-supply using natural gas.

GHG Emission Reduction Methodology

BC Hydro will estimate the impact the PRES Project will have on GHG emission reductions in British Columbia based on the assumptions and methodology set out in section 4.3 of this report. BC Hydro will apply these same assumptions and methodology to estimate the impact that [redacted] generation will have on GHG emission reductions in British Columbia until the PRES Project is in-service. For fiscal 2021 the GHG emissions intensity factors determined in accordance with this methodology are listed below for convenience:

- Average emissions intensity factor for natural gas turbine: [redacted][7];
- Less emissions intensity factor for BC Hydro grid electricity: [redacted][8]; and
- Net emissions intensity factor for electrified loads: [redacted]

Determination of Eligible Loads for GHG Emission Reduction

In fiscal 2019 and fiscal 2020, certain Company X facilities were electrified with the support provided through the Generation Agreement (to ensure reliable electricity supply) and the Incentive Agreement (to provide supporting funds for investment in electrical infrastructure) described in the previous sections. Absent these

[7] The efficiency assumption of 29.5 per cent for gas turbines was developed by calculating the weighted average efficiency from metered data of two customer operated gas turbine electrical generation units.

[8] Source: British Columbia Government: 2017 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions, page 17.

agreements, BC Hydro considers that the Company X loads would not have connected to the BC Hydro transmission system and taken grid service.

As discussed in section 4.2 above, Company X has two sites which are relevant to the prescribed undertakings, the [redacted] (Project 3) and the [redacted] (Project 4) sites.

The Project 3 site was energized from the BC Hydro transmission system in fiscal 2019. This site comprises three gas processing plants and one field/gathering system.

Of the three gas processing plants: one gas processing plant's (Gas Plant 1) load is not eligible for GHG emission calculation because it was previously served from the BC Hydro distribution system; one gas processing plant's (Gas Plant 2) load was new to the BC Hydro system in fiscal 2019; and the final gas processing plant has not yet been constructed.

The load associated with the field/gathering system is being phased into the BC Hydro system. One phase of the field/gathering system load was introduced to the BC Hydro system in fiscal 2019. Another phase of the field/gathering system load was new to the BC Hydro system in fiscal 2020. There were no new phases introduced to the BC Hydro system in fiscal 2021. Further phases of the field/gathering system are expected to join the system in future fiscal years.

For fiscal 2021, total Project 3 load served by BC Hydro was 127,481 MWh, with an estimated GHG emission reduction of 76,234 tonnes CO_2e.

[redacted]

The Project 4 site was energized from the BC Hydro transmission system in fiscal 2019. This site comprises two gas processing plants, one of which was operational in fiscal 2019 (Gas Plant 1), while the other was under construction (Gas Plant 2). Project 4's Gas Plant 2 is joining the BC Hydro system in phases. The first phase connected to the grid in fiscal 2020. No additional phases completed in fiscal 2021 due to project delays. For fiscal 2021, total Project 4 load served by BC Hydro was 162,143 MWh, with an estimated GHG emission reduction of 96,961 tonnes CO_2e .

[redacted]

BC Hydro notes that for each site, electrical energy consumption arising from the electrification of new loads is used to determine associated GHG emission reductions pursuant to the methodology described in section 4.3. These values have been incorporated into Summary of Results

5.4.1 Explanation of Terms

Table 7 below includes a description of the information provided in the results table for LCE Infrastructure Projects. The reason for the indications of "n/a's" is due to the nature of the PRES Project as of March 31, 2021 as described above.

Table 7 LCE Infrastructure Projects Results
Table: Explanation of Terms

Column	Heading	Descriptions
A	Prescribed Undertaking	Type of prescribed undertaking.
B	Name	Project, program, or customer name.
C (i)	Actual ($ million)	Actual costs in millions incurred at the end of the current reporting fiscal.
C (ii)	Cumulative Costs ($ million)	Cumulative actual costs in millions incurred from first year of expenditure to the end of the current reporting fiscal.
C (iii)	Forecast Total ($ million)	Approved Anticipated Total Capital Cost of Project.
D	Capacity of Facility (MW)	Planned facility capacity in megawatts at N-1 and N-0.
E	Total Capacity Committed/Secured (MW)	Cumulative total capacity committed and secured until the end of the current fiscal year in megawatts.
F	Total Customer Load(s) Served (MW)	Cumulative total customer loads served as at the end of the current fiscal year in megawatts.
G	Total Energy Provided to Customers (MW/h)	Cumulative total energy provided to customers as at the end of the current fiscal year in megawatts per hour.
H (i)	Actual: GHG Emissions Reduction Estimates (tonnes CO_2e/year)	Actual GHG Emissions Reduction at the end of the current fiscal period in tonnes of carbon dioxide equivalent per year.
H (ii)	Cumulative: GHG Emissions Reduction Estimates (tonnes CO_2e/year)	Cumulative GHG Emissions Reduction as at the end of the current fiscal period in tonnes of carbon dioxide equivalent per year.
I (i)	Type: Fossil Fuel(s) Avoided Or Displaced	Type of fossil fuels avoided or displaced or likely to be avoided or displaced.
I (ii)	Amount: Fossil Fuel(s) Avoided Or Displaced	Amount of fossil fuels avoided or displaced or likely to be avoided or displaced.

5.4.2 Results Table

Table 8 below provides the results for LCE Infrastructure Projects with expenditures in fiscal 2021.

Table 8 LCE Infrastructure Projects Results for Year Ending March 31, 2021

	A	B	C			D	E	F	G	H		I	
	Prescribed Undertaking	Name	Cost			Capacity of Facility (MW)	Total Capacity Committed/ Secured (MW)	Total Customer Load(s) Served (MW)	Total Energy[1] Provided to Customers (MW/h)	GHG Emissions Reduction Estimates[2] (tonnes CO_2e/year)		Fossil Fuel(s) Avoided or Displaced	
			Actual ($ million) (i)	Cumulative ($ million) (ii)[3]	Forecast Total ($ million) (iii)					Actual (i)	Cumulative (ii)	Type (i)	Amount (ii)
1	T&D	PRES Project	53.3	206.2	285	800 - 950	24	n/a	n/a	n/a	n/a	n/a	n/a
2	[redacted] Generation	[redacted] (Company X)	1.4	4.7	12	24	24	38	289,624	173,195	411,763	n/a	n/a

1 Reflects total new facility load served from the BC Hydro transmission system in fiscal 2021. 164,533 MWh of load is from existing brownfield facilities that fuel-switched to grid power. 125,091 MWh of load is from new greenfield facilities that electrified.

2 The GHG Emissions Reduction Estimates are specific to eligible Project 3 and Project 4 plant loads that were served by BC Hydro in fiscal 2021 in place of natural gas-fired supply.

3. An additional expenditure of $0.3 million was incurred fo [redacted] generation dispatched as an energy resource over 11 days in March 2019. BC Hydro does not consider the associated dispatch costs to be reportable GGRR costs because they were incurred for a purpose ancillary to proving reliable network service.

6 Electric Vehicles Fast Charging Stations Program

6.1 Overview

BC Hydro constructed and operated EV fast charging stations prior to the enactment of section 5 of the GGRR, commencing with the installation of the first charging station in 2013. During the Reporting Period from April 1, 2020 to March 31, 2021, BC Hydro constructed and commissioned EV fast charging stations at five new eligible charging sites. Two EV fast charging stations were installed at four of these sites, and one station was installed at the remaining site. In addition, one additional EV fast charging station was added to each of the 10 existing single station sites. As of March 31, 2021, BC Hydro has 97 EV fast charging stations in operation at 71 sites across the province.

As indicated in Appendix 1 to Attachment 2, all of BC Hydro's fast charging stations meet the requirements of section 5 of the GGRR. That is, all:

- Are available to the public 24 hours a day;
- Do not require users to be a member of a charging network to initiate a charging session;
- Are capable of charging electric vehicles of more than one make; and
- Would be put into operation prior to December 31, 2025;

In addition, as set out in Table 9 below, for those charging stations that are located in a limited municipality, the number of eligible charging sites within the limited municipality did not exceed the site limit in that municipality on the date the charging station was put into operation.

Table 9 Eligible Fast Charging Stations Added - Fiscal 2021

Location/Site	In-Service Date	Number of New EV Fast Charging Sites	Number of EV Fast Charging Stations
Port Alberni (Expansion)	16-April-2020	0	1
Chilliwack (Expansion)	8-Jun-2020	0	1
Campbell River (Expansion)	12-Jun-2020	0	1
Courtenay (Expansion)	12-Jun-2020	0	1
Port McNeill	12-Jul-2020	1	1
Coquitlam - Superstore West (Expansion)	17-Sep-2020	0	1
Grandview Hwy - Superstore (Expansion)	21-Sep-2020	0	1
Prince George	14-Dec-2020	1	2
Burns Lake	15-Dec-2020	1	2
Prince Rupert	15-Dec-2020	1	2
Victoria	23-Mar-2021	1	2
Sechelt (Expansion)	22-Feb-2021	0	1
Surrey - Cloverdale (Expansion)	2-Feb-2021	0	1
UBC - Wesbrook Place (Expansion)	18-Dec-2020	0	1
Vancouver - Kerrisdale (Expansion)	31-Mar-2021	0	1
Total		**5**	**19**

During the Reporting Period, BC Hydro decommissioned three of its EV fast charging sites. These sites are identified in Table 10 below, along with the date of decommissioning as well as the reason the site was decommissioned.

Table 10 Fast Charging Stations Decommissioned - Fiscal 2021

Date of Decommissioning	Site	Reasons for Decommission
Sep 30, 2020	Surrey Central City Hall	Decommissioned since the fast charging station relied on electrical infrastructure that was inside the site host's premises with restricted access.
Oct 1, 2020	Penticton	Decommissioned and re-opened by FortisBC Inc. due to its proximity to FortisBC's network.
Mar 31, 2021	Powertech Labs	Decommissioned due to non-compliance with requirements of the GGRR, and a new station planned at a site nearby Powertech Labs.

6.2 Compliance Verification

The following is an account of the processes for each compliance item:

- **Availability to the public for 24 hours** – All new charging station sites are selected based on the requirement for 24-hour access. If the 24 hour access for a site changes for any reason, BC Hydro will work with the site owner to re-instate 24 hour access or make a decision to decommission the station at the site. For example, BC Hydro negotiated with the Township of Langley to reconfigure the parking lot gates to maintain 24-hour access for the charging station at the Langley Event Centre while closing off the rest of the parking lot after hours;
- **No requirement of membership** - BC Hydro offers a one-time credit card payment service that is free of any network membership requirements. Customers use their smart phone to scan a QR code that takes them to a web portal to process a credit card payment for the charging session;
- **Capability to charge more than one vehicle make** - All BC Hydro's direct current, fast charging stations can charge all EV models from manufacturers

that subscribe to the two industry open standards for charger/car interface – CHAdeMO and CCS; and

- **Decision to Construct or Purchase** - For BC Hydro, “the date the public utility decides to construct or purchase an eligible charging station” is the date when the expenditures associated with the construction or purchase of the eligible charging station are internally approved via an Expenditure Authorization Request (EAR). BC Hydro considers the date when the appropriate approval of the EAR is obtained that it has met the requirement of section 5(2)(b) of the GGRR.
- **Site Limit** – BC Hydro determines the Site Limit for each proposed charging station based on the most recent population numbers published by BC Stats.

6.3 Summary of Results

Appendix 1 to Attachment 2 identifies each of BC Hydro’s 97 eligible charging stations at 71 eligible charging sites as of March 31, 2021. All sites are delineated in the Economic Development Region.

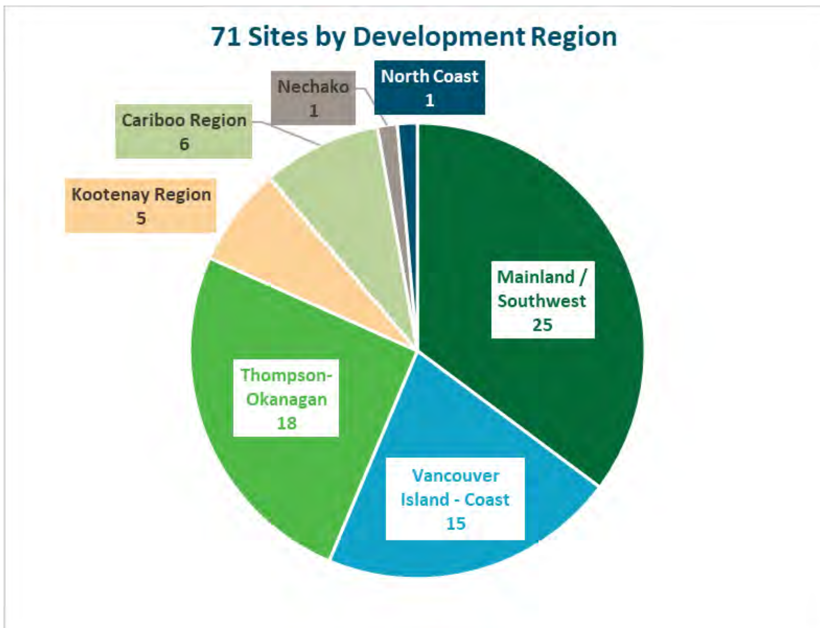
For all eligible charging stations identified in Appendix 1 to Attachment 2, a charging port for BC Hydro at this time is the same as a charging station. That is, each charging station is capable of charging one vehicle at a time, even though each of the 97 charging stations is equipped with two connectors - a CHAdeMO connector and a SAE CCS connector.

The number of charging sessions as well as kWh dispensed (measured by metering currently not yet approved by Measurement Canada) during fiscal 2021 for each eligible charging station is provided in Appendix 1 to Attachment 2.

For most of the sites identified in Appendix 1 to Attachment 2, population statistics are based on the 2016 Census as reported for the year 2020 by BC Stats. In some instances and as identified, the population figures are from the 2016 Census as reported by Statistics Canada. The number of eligible charging stations within each limited municipality as of March 31, 2021 is based on a review of information in Plugshare.com.

The distribution of fast charging sites by Economic Development Region is provided in Figure 3 below.

Figure 3 Distribution of Eligible Charging Sites by Economic Development Region



Greenhouse Gas Reduction (Clean Energy) Regulation Reporting

Attachment 2

Fiscal 2021 Annual Report No. 4

April 2020 to March 2021

Appendix 1

Electric Vehicle Fast Charging Station Program Information as of March 31, 2021

PUBLIC

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

BC Hydro
Power smart

Greenhouse Gas Reduction (Clean Energy) Regulation Reporting

Attachment 3

Annual Expenditures in Total and by Project/Study/Program

PUBLIC

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix HH

Organization Chart

BC Hydro Power smart

- BC Hydro Board of Directors
  - President & Chief Executive Officer, Chris O'Riley
    - Executive Vice-President Site C, Ken McKenzie
    - Vice-President & General Counsel, Ken Duke
    - Vice-President People & Chief Human Resources Officer, Carolynn Ryan
    - Senior Vice-President Integrated Planning, Maureen Daschuk
      - Vice-President Asset Planning, Ajay Kumar
      - Director Engineering Design, Murray Kroeker
      - Director Engineering Services, Shari Carlaw
      - Director Energy Planning & Analytics, Bill Clendinning
      - Director Dam Safety, Bob Schubak
      - Director Interconnections, Frank Lin
    - Senior Vice-President Capital Infrastructure Project Delivery, Al Leonard
      - Vice-President Project Delivery, Melissa Holland
      - Director Indigenous Relations, Lindsay Thompson
      - Director Environment, Karen Popoff
      - Director Properties, Joanna Sofield
    - Executive Vice-President Operations, Charlotte Mitha
      - Director Line Field Operations, Lanny Sawchuck
      - Director Stations Field Operations, Richard Brittin
      - Director T&D System Operations, Paul Choudhury
      - Director Generation System Operations, Heather Matthews
      - Director Program & Contract Management, Jesse Brown
      - Director Distribution Design & Customer Connect, Ranjeet Gill
      - Director Construction Services, Matt Wilson
    - Senior Vice-President Safety & Chief Compliance Officer, Kirsten Peck
      - Director Safety, Stephanie Benay
      - Director Learning & Development, Tracey Armatage
      - Director Projects, Fiona Taylor
      - Director Compliance, Kees Jansen
      - Manager Security & Emergency Management, Ben Peco
    - Executive Vice-President Finance, Technology, Supply Chain & Chief Financial Officer, David Wong
      - Chief Supply Chain Officer, Gurj Parmar
      - Chief Information Officer, Kip Morison
      - Chief Accounting Officer, Ryan Layton
      - Treasurer & Director Financial Evaluation, Michael Savidant
      - Director Finance - Site C, Henry Honda
      - Director Audit Services, Albert Lagnado
    - Senior Vice-President Customer & Corporate Affairs, Vacant*
      - Vice-President Customer Service, Keith Anderson
      - Chief Regulatory Officer, Chris Sandve
      - Chief Communications Officer, Darwin Sauer
      - Director Conservation & Energy Management, Stephen Hobson

Subsidiaries

Powerex Corp

Powertech Labs

* Senior Vice-President, Customer & Corporate Affairs role is under recruitment as of August 31, 2021.

Effective November 01, 2021

BC Hydro Fiscal 2023 – Fiscal 2025
Revenue Requirements Application

Appendix II

Proposed Fiscal 2023 to Fiscal 2025 Rates

Table of Contents

List of Tables

1 Introduction

Section 2 of this appendix describes how the requested rate increase will be applied to the default, tiered rates for BC Hydro's residential and transmission service rate classes using BCUC-approved pricing principles. The default rates for the other rate classes do not require the use of the BCUC-approved pricing principles and have been determined by increasing each component of the rate by the requested rate increase.

Section 3 contains the fiscal 2023 to rates which are requested to be effective April 1, 2022 on an interim and refundable basis. It also contains the fiscal 2024 and fiscal 2025 interim rates under the proposed rate increases.

Table II-1 of this appendix sets out the rates that will be applicable to each of the Rate Schedules in each rate class for fiscal 2023 to fiscal 2025 and compares them to the fiscal 2022 rates, which were approved on a final basis by BCUC Order No. G-187-21.

BC Hydro's Open Access Transmission Tariff (**OATT**) rates are explained in Chapter 9 of the Application. Table II-2 of this appendix sets out the applicable OATT rates for fiscal 2023 to fiscal 2025 and compares them to the fiscal 2022 rates, which were approved on a final basis by BCUC Order No. G-187-21.

2 Application of Rate Increases

2.1 Residential Rates

2.1.1 Rate Schedules (RS) 1101, 1121 – Residential Service

Rate Schedule 1101 is the Residential Inclining Block (**RIB**) rate, which is the default Residential rate, while Rate Schedule 1121 is the RIB rate for Multiple Residential Service. The RIB rate structure for Rate Schedules 1101 and 1121 consists of a Basic Charge and a two-step inclining block Energy Charge, with the first step called the Step 1 Energy Charge and the second step called the Step 2 Energy Charge. The RIB rate was implemented on October 1, 2008.

The term “pricing principles” refers to how revenue requirements rate increases are applied to each of the RIB rate’s pricing elements (Step 1 Energy Charge, Step 2 Energy Charge and Basic Charge). The approved RIB pricing principles for Rate Schedules 1101 and 1121 for each fiscal year in the Test Period are to uniformly increase the three pricing elements of the RIB rate by the amount of the approved rate increase. These pricing principles have been in place for a number of years and were most recently approved for fiscal 2021 and fiscal 2022 by BCUC Order No. G-62-20.

BC Hydro uses the approved pricing principles to derive the RIB rates shown in Table II-1 below. To derive the RIB rates, each of the three components of the RIB rate are increased by the proposed rate increase of 0.62 per cent for fiscal 2023, 0.97 per cent for fiscal 2024 and 2.18 per cent for fiscal 2025. BC Hydro is currently exploring RIB rate restructuring options with customers and stakeholders and is planning to file a rate application with the BCUC by February 2022. The approval of a new rate structure may result in changes to the rates reported in the table below.

2.2 Transmission Service Rates

2.2.1 Rate Schedule (RS) 1823 – Transmission Service – Stepped Rate

The pricing principles for the Rate Schedule 1823 Stepped Rate were first approved for fiscal 2017 to fiscal 2019 by Directive 9 of BCUC Order No. G-5-17, were extended to fiscal 2020 and fiscal 2021 by BCUC Order No. G-93-19, and were further extended by BCUC Order No. G-131-21 until March 31, 2023 or until a new rate structure for RS 1823 customers is approved by the BCUC.

Under the pricing principles:

- For fiscal 2017, the Tier 2 energy charge was set to the lower end of BC Hydro's energy long run marginal cost and the Tier 1 energy charge was set to reflect the 4.0 per cent revenue requirements rate increase according to the bill neutrality approach, i.e., 90 per cent of the Tier 1 energy charge plus 10 per cent of the Tier 2 energy charge is equal to the flat energy charge (Rate Schedule 1827 energy charge or the Rate Schedule 1823 Energy Charge A); and
- For fiscal 2018 to fiscal 2022, the applicable revenue requirements rate increases were applied equally to both Tier 1 and Tier 2 energy charges.

The fiscal 2023 to fiscal 2025 Transmission Service RS 1823 Stepped Rates in Table II-1 are based on the approved pricing principles to the end of fiscal 2023. Therefore, the proposed rate increases of 0.62 per cent in fiscal 2023, 0.97 per cent in fiscal 2024 and 2.18 per cent in fiscal 2025 are applied equally to the RS 1823 Tier 1 energy charge and the Tier 2 energy charge. BC Hydro is currently exploring Rate Schedule 1823 restructuring options with transmission service customers and stakeholders, which is expected to result in a rate application and approval of a new rate structure for RS 1823 customers. This would result in changes to RS 1823 and possibly changes in related transmission service rates reported in the table below.

3 Summary of Fiscal 2023 to Fiscal 2025 Rates

Table II-1 below provides the rates in each BC Hydro rate schedule for fiscal 2023 to fiscal 2025 and a comparison to the fiscal 2022 rates which were approved on a final basis by BCUC Order No. G-187-21.

1 **Table II-1 Fiscal 2022 to Fiscal 2025 Rates**

Rate Class	Rate Schedule	Rate	Fiscal 2022	Fiscal 2023	Fiscal 2024	Fiscal 2025
			Approved 1.00%	Rate Increase 0.62%	Rate Increase 0.97%	Rate Increase 2.18%
Residential	1101/1121	Basic Charge ($/day)	0.2077	0.2090	0.2110	0.2156
		Step-1 energy charge ($/kWh)	0.0939	0.0945	0.0954	0.0975
		Step-2 energy charge ($/kWh)	0.1408	0.1417	0.1431	0.1462
Residential	1105 (closed)	Energy charge ($/kWh)	0.0858	0.0926	0.0994	0.1062
Residential Zone II	1107/1127	Basic Charge ($/day)	0.2215	0.2229	0.2251	0.2300
		Step-1 energy charge ($/kWh)	0.1125	0.1132	0.1143	0.1168
		Step-2 energy charge ($/kWh)	0.1932	0.1944	0.1963	0.2006
Residential	1148 (closed)	Basic Charge ($/day)	0.2215	0.2229	0.2251	0.2300
		Energy charge $/kWh	0.1125	0.1132	0.1143	0.1168
Residential	1151/1161	Basic Charge ($/day)	0.2215	0.2229	0.2251	0.2300
		Energy charge $/kWh	0.1125	0.1132	0.1143	0.1168

Rate Class	Rate Schedule	Rate	Fiscal 2022	Fiscal 2023	Fiscal 2024	Fiscal 2025
			Approved 1.00%	Rate Increase 0.62%	Rate Increase 0.97%	Rate Increase 2.18%
Exempt General Service	1200/1201/1210/ 1211	Basic Charge ($/day)	0.2656	0.2672	0.2698	0.2757
		Demand rate - Step-1 ($/kW)	0	0	0	0
		Demand rate - Step-2 ($/kW)	6.47	6.51	6.57	6.71
		Demand rate - Step-3 ($/kW)	12.41	12.49	12.61	12.88
		Energy charge - Tier 1 ($/kWh)	0.1264	0.1272	0.1284	0.1312
		Energy charge - Tier 2 ($/kWh)	0.0607	0.0611	0.0617	0.063
General Service	1205/1206/1207	Energy charge - Tier 1 ($/kWh)	0.0615	0.0619	0.0625	0.0639
		Energy charge - Tier 2 ($/kWh)	0.0402	0.0404	0.0408	0.0417
Small General Service Zone II	1234	Basic Charge ($/day)	0.2656	0.2672	0.2698	0.2757
		Energy charge - Tier 1 ($/kWh)	0.1264	0.1272	0.1284	0.1312
		Energy charge - Tier 2 ($/kWh)	0.2104	0.2117	0.2138	0.2185
Distribution Service	1253	Monthly Minimum energy charge($/month)	48.70	49.00	49.48	50.56

Rate Class	Rate Schedule	Rate	Fiscal 2022	Fiscal 2023	Fiscal 2024	Fiscal 2025
			Approved 1.00%	Rate Increase 0.62%	Rate Increase 0.97%	Rate Increase 2.18%
Large General Service Zone II	1255/1256/1265/1266	Basic Charge ($/day)	0.2656	0.2672	0.2698	0.2757
		Energy charge - Tier 1 ($/kWh)	0.1264	0.1272	0.1284	0.1312
		Energy charge - Tier 2 ($/kWh)	0.2104	0.2117	0.2138	0.2185
Distribution Service	1268	Energy charge ($/kWh)	0.00196	0.00197	0.00199	0.00203
Shore Power Service (Distribution)	1280	Monthly Charge ($/month)	150	150	150	150
		Energy charge ($/kWh)	0.10442	0.10507	0.10610	0.10842
Small General Service	1300/1301/1310/1311	Basic Charge ($/day)	0.3622	0.3644	0.3679	0.3759
		Energy charge ($/kWh)	0.1245	0.1253	0.1265	0.1293
Small General Service	1360	$ per minute	0.1200	0.1207	0.1219	0.1246

Rate Class	Rate Schedule	Rate	Fiscal 2022	Fiscal 2023	Fiscal 2024	Fiscal 2025
			Approved 1.00%	Rate Increase 0.62%	Rate Increase 0.97%	Rate Increase 2.18%
Irrigation	1401	Irrigation season energy charge ($/kWh)	0.0608	0.0612	0.0618	0.0631
		Non-irrigation season energy charge - Tier 1 ($/kWh)	0.0608	0.0612	0.0618	0.0631
		Non-irrigation season energy charge - Tier 2 ($/kWh)	0.4821	0.4851	0.4898	0.5005
		Minimum charge irrigation season $/kW	6.08	6.12	6.18	6.31
		Minimum charge non-irrigation season if consumption >500 kWh ($ per kW)	48.63	48.93	49.40	50.48
Medium General Service	1500/1501/1510/ 1511	Basic Charge ($/day)	0.2656	0.2672	0.2698	0.2757
		Demand rate - all kW ($/kW)	5.38	5.41	5.46	5.58
		Energy charge - all kWh ($/kWh)	0.0962	0.0968	0.0977	0.0998
Medium General Service	1560	$ per minute	0.2100	0.2113	0.2133	0.2179
Medium General Service	1561	$ per minute	0.2700	0.2717	0.2743	0.2803
Large General Service	1600/1601/1610/ 1611	Basic Charge ($/day)	0.2656	0.2672	0.2698	0.2757
		Demand rate – all kW ($/kW)	12.26	12.34	12.46	12.73
		Energy charge - all kWh ($/kWh)	0.0602	0.0606	0.0612	0.0625

Rate Class	Rate Schedule	Rate	Fiscal 2022	Fiscal 2023	Fiscal 2024	Fiscal 2025
			Approved 1.00%	Rate Increase 0.62%	Rate Increase 0.97%	Rate Increase 2.18%
Large General Service	1640 / 1641 / 1642 / 1643	Basic Charge ($/day)	0.2656	0.2672	0.2698	0.2757
		Demand rate – all kW	12.26	12.34	12.46	12.73
		Energy charge - all kWh	0.0741	0.0746	0.0753	0.0769
Large General Service	1650 / 1651 / 1652 / 1653	Basic Charge ($/day)	0.2656	0.2672	0.2698	0.2757
		Demand rate – all kW	0	0	0	0
		Energy charge - all kWh	0.0912	0.0917	0.0926	0.0947
Street Lighting	1701	50 W or less LED ($/month)	15.23	15.32	15.47	15.81
		51-80 W LED ($/month)	18.96	19.08	19.27	19.69
		81-120 W LED ($/month)	23.74	23.89	24.12	24.65
		>120 W LED ($/month)	27.85	28.02	28.29	28.91
		100 SV fixture rate ($/month)	19.47	19.59	19.78	20.21
		150 SV fixture ($/month)	23.23	23.37	23.60	24.11
		200 SV fixture ($/month)	26.82	26.99	27.25	27.84
		175 MV fixture ($/month)	21.40	21.53	21.74	22.21
		250 MV fixture ($/month)	24.66	24.81	25.05	25.60
		400 MV fixture ($/month)	31.78	31.98	32.29	32.99

Rate Class	Rate Schedule	Rate	Fiscal 2022	Fiscal 2023	Fiscal 2024	Fiscal 2025
			Approved 1.00%	Rate Increase 0.62%	Rate Increase 0.97%	Rate Increase 2.18%
Street Lighting	1702	Each Unmetered fixture ($/watt per month)	0.0375	0.0377	0.0381	0.0389
		Each Metered fixture ($/kWh)	0.1125	0.1132	0.1143	0.1168
Street Lighting	1703	Energy charge ($/watt per month)	0.0375	0.0377	0.0381	0.0389
		Contact rate ($/contact per month)	1.12	1.13	1.14	1.16
Street Lighting	1704	Energy charge $/kWh	0.1125	0.1132	0.1143	0.1168
Street Lighting	1755 (closed)	1. Pole owned by Customer				
		175 MV or 100 SV fixture charge ($ per month)	18.25	18.36	18.54	18.94
		400 MV or 150 SV fixture charge ($ per month)	31.46	31.66	31.97	32.67
		2. Pole on public property				
		175 MV or 100 SV fixture charge ($ per month)	19.38	19.50	19.69	20.12
		400 MV or 150 SV fixture charge ($ per month)	32.60	32.80	33.12	33.84

Rate Class	Rate Schedule	Rate	Fiscal 2022	Fiscal 2023	Fiscal 2024	Fiscal 2025
			Approved 1.00%	Rate Increase 0.62%	Rate Increase 0.97%	Rate Increase 2.18%
		3. Pole paid by BC Hydro				
		175 MV or 100 SV fixture charge ($ per month)	23.87	24.02	24.25	24.78
		400 MV or 150 SV fixture charge ($ per month)	37.57	37.80	38.17	39.00
Transmission Service	1823	Demand rate ($/kVA)	8.642	8.696	8.780	8.971
		Energy charge A ($/kWh)	0.05065	0.05096	0.05145	0.05257
		Energy charge B - Tier 1 ($/kWh)	0.04507	0.04535	0.04579	0.04679
		Energy charge B - Tier 2 ($/kWh)	0.10095	0.10158	0.10257	0.10481
		Minimum demand ($/kVA)	8.642	8.696	8.78	8.971
Transmission Service	1825	Demand rate ($/kVA)	8.642	8.696	8.78	8.971
		Winter HLH energy charge (below 90%) ($/kWh)	0.04507	0.04535	0.04579	0.04679
		Winter HLH energy charge (above 90%) ($/kWh)	0.11265	0.11335	0.11445	0.11695
		Winter LLH energy charge (below 90%) ($/kWh)	0.04507	0.04535	0.04579	0.04679

Rate Class	Rate Schedule	Rate	Fiscal 2022	Fiscal 2023	Fiscal 2024	Fiscal 2025
			Approved 1.00%	Rate Increase 0.62%	Rate Increase 0.97%	Rate Increase 2.18%
		Winter LLH energy charge (above 90%) ($/kWh)	0.10210	0.10273	0.10373	0.10599
		Spring energy charge (below 90%) ($/kWh)	0.04507	0.04535	0.04579	0.04679
		Spring energy charge (above 90%) ($/kWh)	0.09093	0.09149	0.09238	0.09439
		Remaining energy charge (below 90%) ($/kWh)	0.04507	0.04535	0.04579	0.04679
		Remaining energy charge (above 90%) ($/kWh)	0.09971	0.10033	0.1013	0.10351
Transmission Service	1827	Demand rate ($/kVA)	8.642	8.696	8.780	8.971
		Energy charge ($/kWh)	0.05065	0.05096	0.05145	0.05257
		Minimum demand ($/kVA)	8.642	8.696	8.780	8.971
Transmission Service	1852	Excess Demand rate ($/kVA)	8.642	8.696	8.780	8.971
Transmission Service	1853	Minimum Monthly Charge ($/month)	48.70	49.00	49.48	50.56
Transmission Service	1880	Administrative Charge per Period of Use ($)	150.00	150.00	150.00	150.00
		Energy charge ($/kWh)	0.10095	0.10158	0.10257	0.10481

Rate Class	Rate Schedule	Rate	Fiscal 2022	Fiscal 2023	Fiscal 2024	Fiscal 2025
			Approved 1.00%	Rate Increase 0.62%	Rate Increase 0.97%	Rate Increase 2.18%
Shore Power Service (Transmission)	1891	Monthly Charge ($/month)	150	150	150	150
		Energy charge ($/kWh)	0.10095	0.10158	0.10257	0.10481
Transmission Service FortisBC	3808	Demand rate ($/kW)	8.642	8.696	8.780	8.971
		Energy charge - tranche 1 ($/kWh)	0.05065	0.05096	0.05145	0.05257
		Energy charge – tranche 2 ($/kWh)	0.09509	0.09509	0.09509	0.09509
Deferral Account Rate Rider	1901	Per cent	0	0	0	0

Table II-2 below provides the OATT rates for fiscal 2023 to fiscal 2025 and a comparison to the fiscal 2022 OATT rates which were approved on a final basis by BCUC Order No. G-187-21 in the previous application.

1 **Table II-2 Fiscal 2022 to Fiscal 2025 OATT Rates**

Rate Schedule	Rate Class	Fiscal 2022 Decision	Fiscal 2023	Fiscal 2024	Fiscal 2025
Attachment H	**NITS Revenue Requirement ($)**	978,303,960	989,403,600	1,004,795,640	950,588,880
00	**NITS Monthly Rate ($)**	81,525,330	82,450,300	83,732,970	79,215,740
01	**Long Term Firm Point-to-Point**				
	Yearly - $/MW of Reserved Capacity per year	78,262	82,713	84,129	79,914
	Short Term Firm and Non-Firm Maximum Price for Delivery				
	Monthly - $/MW of Reserved Capacity per month	6,521.81	6,892.77	7,010.73	6,659.52
	Weekly - $/MW of Reserved Capacity per week	1,505.03	1,590.64	1,617.86	1,536.81
	Daily - $/MW of Reserved Capacity per day	214.42	226.61	230.49	218.94
	Hourly - $/MW of Reserved Capacity per hour	8.93	9.44	9.60	9.12
03	**Scheduling, System Control and Dispatch Service ($)**				
	per MW of Reserved Capacity per hour	0.152	0.138	0.141	0.140

BC Hydro Fiscal 2023 to Fiscal 2025
Revenue Requirements Application

Appendix JJ

Planned Mandatory Reliability Standards Investments

PUBLIC

CONFIDENTIAL ATTACHMENT

FILED WITH BCUC ONLY