BC Hydro
Power smart

Fred James
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

October 3, 2019

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. 1598990
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2020 to Fiscal 2021 Revenue Requirements Application

In response to a commitment made at the March 15, 2019 Workshop and information requests received to-date and in accordance with BCUC Order G-218-19, BC Hydro writes to file its June 2019 Load Forecast, covering fiscal 2020 to fiscal 2039.

In the Application, BC Hydro provided an October 2018 Load Forecast, covering fiscal 2019 to fiscal 2024. The calculation of the test period revenue requirements, as updated by the Evidentiary Update, uses actual financial results for April 2019 and May 2019 and the October 2018 Load Forecast for the remainder of fiscal 2020 and all of fiscal 2021.

The June 2019 Load Forecast was completed after the financial inputs into the Evidentiary Update were finalized and is not reflected in the Evidentiary Update. As discussed further in this submission, the June 2019 Load Forecast is, on average, within 0.1 per cent of the October 2018 Load Forecast for the Test Period. Accordingly, and given that the Evidentiary Update incorporated two months of actual results for fiscal 2020, BC Hydro is not proposing any further adjustments to the revenue forecast provided in the Evidentiary Update.

BC Hydro previously provided a comprehensive 20-year load forecast in the 2013 Integrated Resource Plan (**IRP**) and in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. BC Hydro's 2021 IRP filing will include a new comprehensive load forecast, which will reflect more current information and assumptions. Accordingly, BC Hydro suggests that Information Requests on the June 2019 Load Forecast be focused on the Test Period of the Application (fiscal 2020 and fiscal 2021). Questions regarding the years beyond the Test Period are more appropriately addressed in the 2021 IRP proceeding.

Appendix A of this filing is redacted in the public version as it contains confidential customer-specific information and is being made available to the BCUC only. Customer-specific information is confidential and made available to the BCUC only, to protect the commercial interests of those customers.

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

cs/rh

Enclosure

BC Hydro Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Twenty-Year Load Forecast

October 3, 2019

Table of Contents

List of Figures

List of Tables

Appendices

1 Introduction

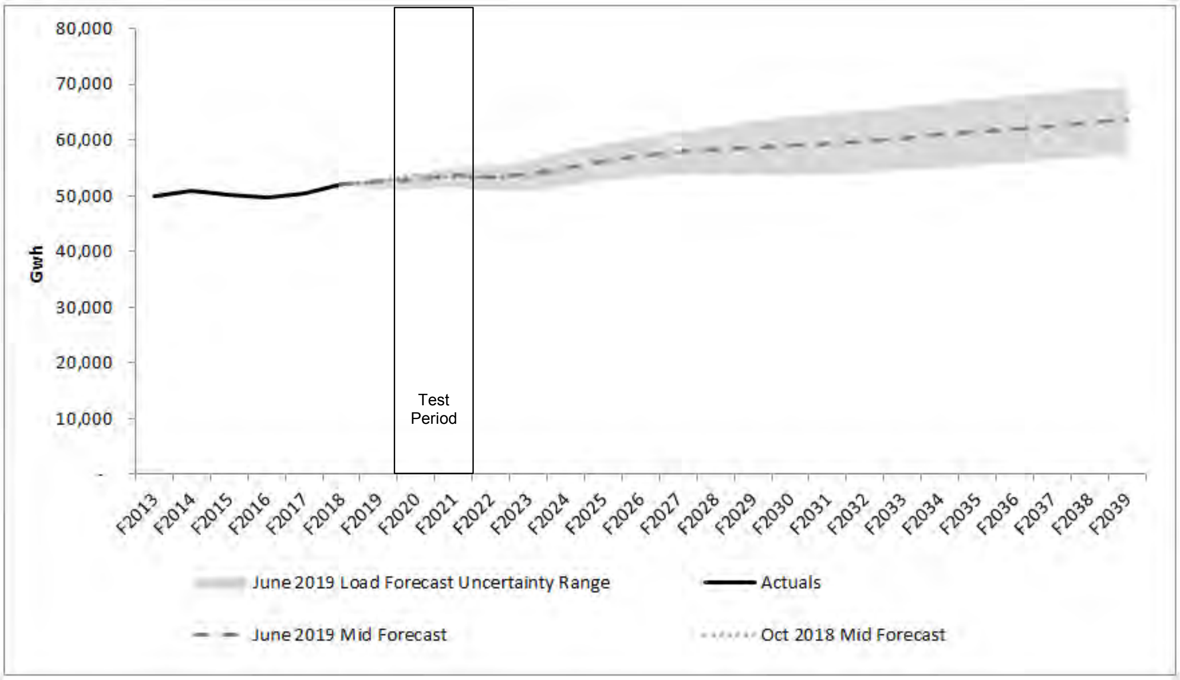
BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (**Application**) provided an October 2018 Load Forecast, covering fiscal 2019 to fiscal 2024. The calculation of the Test Period revenue requirements, as updated by the Evidentiary Update, uses actual financial results for April 2019 and May 2019 and the October 2018 Load Forecast for the remainder of fiscal 2020 and all of fiscal 2021.

In response to a commitment made at the March 15, 2019 Workshop and information requests received to date, BC Hydro now provides a June 2019 Load Forecast, covering fiscal 2020 to fiscal 2039. Fiscal 2022 to fiscal 2039 are outside of the Test Period covered by the Application and are provided for information purposes only.

The June 2019 Load Forecast was prepared as an interim step to inform BC Hydro's future capital planning cycle and the February 2020 Service Plan. In early 2020, BC Hydro will complete an updated comprehensive 20-year load forecast to inform the 2021 Integrated Resource Plan (**IRP**).

Figure 1 below provides the forecast total firm sales from the June 2019 Load Forecast and the October 2018 Load Forecast.

Figure 1 June 2019 Load Forecast of Total Firm Sales (Fiscal 2019 to Fiscal 2039)



In summary, the June 2019 Load Forecast:

- ***Is primarily an extension of the October 2018 Load Forecast.*** With the exception of Electric Vehicles (**EVs**), the methodology is the same. Where appropriate, customer-specific updates have been made to the Large Industrial and Light Industrial sectors and updated assumptions have been applied for codes and standards, economic projections and rate impact adjustments. Further information is provided in section 2 below;
- ***Is on average within 0.1 per cent of the October 2018 Load Forecast for the Test Period.*** Accordingly, and given that the Evidentiary Update incorporated two months of actual results for fiscal 2020, BC Hydro is not proposing any further adjustments to the revenue forecast provided in the Evidentiary Update. Any variances between forecast and actual revenue would

be deferred in the normal course for future recovery from, or refund to, ratepayers. Further information is provided in section 3 below; and

- ***Expects annual load growth of approximately 1 per cent for fiscal 2020 to fiscal 2039.*** There is uncertainty when forecasting load growth over the long-term and any new developments affecting input variables which drive the forecast will be reflected in the load forecast that informs BC Hydro's 2021 IRP. Further information is provided in section 4 below.

In response to commitments made during the course of this proceeding and to provide further information on the June 2019 Load Forecast, the following appendices are included in this filing:

- Appendix A provides customer-specific information on a confidential basis, available to the BCUC only;[1]
- Appendix B provides a Peak Forecast and a description of the peak forecast methodology;
- Appendix C provides an updated South Peace Region Load Forecast; and
- Appendix D provides updated Load Resource Balance tables.

2 Methodology and Inputs for June 2019 Load Forecast Are Primarily Unchanged

With the exception of the forecast for EVs, the June 2019 Load Forecast was developed using the same methodology as the October 2018 Load Forecast, which is set out in Appendix O of the Application. Where appropriate, customer-specific updates have been made to the Large Industrial and Light Industrial sectors and updated assumptions have been applied for codes and standards, economic

[1] Customer specific information is confidential and made available to the BCUC only, to protect the commercial interests of those customers.

projections, and rate impact adjustments. These updates are summarized in Table 1 below.

Table 1 Changes in Methodology and Input Assumptions between the October 2018 Load Forecast and the June 2019 Load Forecast

Sector	Input	October 2018	June 2019
Residential & Commercial	Economic Forecast	Conference Board of Canada (**CBoC**) June 2018	Same
	Energy Information Administration Data	2018	Same
	Codes and Standards Overlap	Refer to section 12 of Appendix O of the Application	Refer to section 3.1.1 below
	Calibration Period	Fiscal 2009 to Fiscal 2018	Same
	Electric Vehicles (**EVs**)	Refer to section 9 of Appendix O of the Application	Refer to section 3.1.2 below[2]
Large Industrial	Account by Account Assessment	Comprehensive Assessment[3]	Specific Customer Updates[4]
Light Industrial	GDP Forecast	BC Ministry of Finance September 2018 Q1 Report for fiscal 2019 to fiscal 2023 CBoC June 2018 for fiscal 2024 to fiscal 2039	BC Ministry of Finance February 2019 Budget for fiscal 2019 to fiscal 2023 CBoC June 2018 for fiscal 2024 to fiscal 2039
	Account by Account Assessment	Comprehensive Assessment[3]	Specific Customer Updates[4]
Adjustments	Rate Impacts[5]	2013 10 Year Rates Plan	Comprehensive Review – Phase One
	DSM Savings	Fiscal 2020-Fiscal 2022 DSM Plan	Same

2 In addition to the changes described in section 3.1.2, the high and low bands from the Monte Carlo simulation were modified to exclude the EV forecast. The discrete high and low EV forecasts were then added to the Monte Carlo results.

3 Incorporated forecasts and market assessments from third-party industry experts, market research and customer information.

4 Primarily from customer information and market research. No formal update to third-party expert information.

5 For further information, please refer to section 3.5 below.

3 June 2019 Load Forecast is Similar to October 2018 Load Forecast Over Test Period

The June 2019 Load Forecast was completed after the financial inputs into the Evidentiary Update were finalized and is not reflected in the Evidentiary Update. However, as shown in Figure 2 below, the June 2019 Load Forecast is on average within 0.1 per cent of the October 2018 Load Forecast for the Test Period. Accordingly, and given that the Evidentiary Update incorporated two months of actual results for fiscal 2020, BC Hydro is not proposing any further adjustments to the revenue forecast provided in the Evidentiary Update. Any variances between forecast and actual revenue would be deferred in the normal course for future recovery from, or refund to, ratepayers.

Figure 2 Forecast Adjustments from the October 2018 Load Forecast to the June 2019 Load Forecast for Fiscal 2020 and Fiscal 2021 (GWh)

The following sub-sections provide explanations of the changes shown in Figure 2 above.

3.1 Residential and Commercial

The changes in the Residential and Commercial sectors are due to updated codes and standards adjustments and an updated methodology for EVs.

3.1.1 Codes and Standards

As discussed in section 12 of Appendix O of the Application, adjustments are made to account for the overlap between savings included in BC Hydro's Statistically Adjusted End Use (**SAE**) model results and savings derived from BC Hydro's Demand-Side Management (**DSM**) Plan. This overlap results because there are energy savings from codes and standards that are reflected in both our DSM Plan and the U.S. Energy Information Administration (**EIA**) assumptions included in the SAE model.

In 2019, Navigant Inc. completed an independent review of the overlap in codes and standards included in the EIA projections and BC Hydro's DSM Plan. The review reconciled codes and standards set out by legislation in British Columbia and Canada, which are reflected in BC Hydro's DSM Plan, with the U.S. federal codes and standards reflected in the EIA projections. The review found that there were additional end uses technologies which overlapped between the EIA and DSM plan relative to previous assumptions reflected in the October 2018 Load Forecast. Accordingly, an updated adjustment was made for Codes and Standards in the June 2019 Load Forecast. The change in codes and standards estimates relative to the October 2018 Load Forecast is less than 50 GWh per year for fiscal 2020 and fiscal 2021.

3.1.2 Electric Vehicles

The June 2019 Load Forecast uses a new methodology for EVs, to align with the CleanBC Plan for light duty electric vehicles. Specifically, the *Zero-Emission Vehicles Act* (**ZEV Act**) was enacted on May 30, 2019. The ZEV Act stipulates the percentage of new light duty car and truck sales in B.C. that must be zero emission vehicles, 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 June 2019 Load Forecast is based on these requirements and the associated incentives because, at a minimum, EV sales would be expected to reach the levels required by legislation. The high-EV scenario assumes EV models are more available, the purchase cost declines, consumers' preferences change, and more infrastructure becomes available. In other words, the high EV forecast assumes that the natural uptake of EVs is greater than the requirements set out in the ZEV Act, resulting in a higher total EV forecast. Due to the significant level of uncertainty when developing a long-term EV forecast, BC Hydro developed its mid-EV forecast by taking the average between the high and low EV forecasts.

3.2 Large Industrial

Customer specific updates were made to the Large Industrial sector to reflect new information since the October 2018 Load Forecast was finalized. Further information is provided in the sub-sections below and Appendix A provides detailed customer-specific information on a confidential basis to the BCUC only.

3.2.1 Mining

Forecast sales to the mining sub-sector over the Test Period have decreased, primarily due to the closure of the Mt. Polley mine which was announced in January 2019. This decrease is partially offset by increased consumption by some other customers due to new equipment and improved operational efficiencies.

3.2.2 Forestry

Forecast sales to the forestry sub-sector in fiscal 2020 have decreased as a result of temporary shift and mill curtailments at some transmission serviced forestry mills due to fibre shortages and market conditions. Most of the curtailments have occurred in the wood products segment. The October 2018 Load Forecast assumed that electricity sales to the forestry sub-sector would decline; however, the recent closures and curtailments have been greater than forecast and most of this incremental impact is reflected in the June 2019 Load Forecast. Forecast sales to the forestry sub-sector in fiscal 2021 increase due to deferred closure risk for a major pulp and paper mill. This deferred closure risk more than offsets the decline in fiscal 2020 because a single pulp and paper mill consumes significantly more electricity than multiple sawmills.

3.2.3 Oil and Gas

Forecast sales to the oil and gas sub-sector over the Test Period have decreased due to reduced gas production at existing facilities, deferred expansions at existing facilities and a cancelled project expansion. These decreases are partially offset by increased load from a facility that began commercial operations earlier than expected. Load from existing facilities is expected to increase over time as gas production at those facilities escalates to meet supply obligations to LNG Canada.

3.2.4 Other

Forecast sales to the other sub-sector over the Test Period have decreased, primarily due to delays and reduced load expectations for cryptocurrency customers.

3.3 Light Industrial

Forecast sales to the Light Industrial sub-sector over the Test Period have decreased, primarily due to temporary shift and mill curtailments and permanent mill closures at some distribution serviced forestry mills. This decrease in the wood products segment is partially offset by increased sales due to an updated GDP forecast.

3.4 Other Utilities, Irrigation, and Other Entities

BC Hydro's methodology for forecasting sales to other utilities, irrigation and street lighting customers is summarized in section 3.2.9 of Chapter 3 of the Application. The adjustments shown in Figure 2 above reflect updated assumptions in these and other areas. A detailed breakdown of the changes in the June 2019 Load Forecast relative to the October 2018 Load Forecast is provided in confidence to the BCUC in Appendix A.

3.5 Rate Impacts

The difference in the rate impacts between the June 2019 Load Forecast and the October 2018 Load Forecast occurs because the load forecast prior to rate impacts has changed and because BC Hydro has updated the five-year net bill increase forecast used to calculate rate impacts. Consistent with the October 2018 Load Forecast and the findings of an electricity price elasticity study conducted by DNV GL, which is provided as Appendix Q of the Application, the June 2019 Load Forecast uses a price elasticity assumption of -0.1. The June 2019 Load Forecast rate impact adjustment is based on the five-year net bill increase forecast provided in the Government of B.C.'s Phase One Final Report on the Comprehensive Review of BC Hydro (Appendix C of the Application). The five-year net bill increase forecast provided in the Evidentiary Update was not used as it was not available at the time the inputs into the June 2019 Load Forecast were finalized. If the five-year net bill increase forecast provided in the Evidentiary Update was used, forecast load in the Test Period would increase by approximately 80 GWh on average, all else equal.

4 June 2019 Load Forecast Expects Annual Load Growth of Approximately 1 per cent Over Next 20 Years

As shown in Table 2 below, on a billed sales basis, the June 2019 Load Forecast expects load growth of approximately one per cent per year from fiscal 2020 to fiscal 2039. The June 2019 Load Forecast was prepared as an interim step to inform BC Hydro's capital planning cycle and the February 2020 Service Plan. In early 2020, BC Hydro will complete an updated comprehensive 20-year load forecast to inform the 2021 IRP.

Table 2 Total Domestic Sales after DSM and Rate Impacts (GWh)

Fiscal Year	October 2018 Load Forecast	June 2019 Load Forecast
F2020	**53,561**	53,103
F2021	**53,253**	53,652
F2022	53,090	53,128
F2023	53,434	53,831
F2024	54,552	55,040
F2025		56,226
F2026		57,001
F2027		57,845
F2028		58,192
F2029		58,633
F2030		58,913
F2031		59,336
F2032		59,795
F2033		60,297
F2034		60,835
F2035		61,403
F2036		61,924
F2037		62,490
F2038		63,043
F2039		63,592

4.1 Risk and Uncertainties

As shown in Figure 1 above, BC Hydro's load forecast includes projections for the mid, high and low forecast. The long-term risks and uncertainties for the June 2019 forecast are consistent with those described in section 3.3.6 of Chapter 3 of the Application. The June 2019 Load Forecast reflects the CleanBC plan during the Test Period as it incorporates changes to the EV methodology to align with the CleanBC Plan for light duty electric vehicles. Further information is provided in section 3.1.2 above.

BC Hydro Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Twenty-Year Load Forecast

Appendix A

Customer Specific Updates

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Customer Specific Updates

The following table provides the key updates to customer specific assumptions in the June 2019 Load Forecast for the Large Industrial sector, Other Utilities, Irrigation, and Other Sales.

Table A-1 Differences Between June 2019 Load Forecast and October 2018 Load Forecast for Large Industrial and Other Customers (GWh)

[redacted]

[redacted]

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Revenue Requirements Application

Twenty-Year Load Forecast

Appendix B

June 2019 Peak Forecast

1. June 2019 Peak Load Forecast

BC Hydro develops peak load forecasts as well as energy load forecasts. Peak load forecasts indicate the peak capacity required to reliably meet the instantaneous demands on the system. As indicated in BC Hydro's responses to AMPC IR 2.23.3 and INCE IR 1.8.8, the October 2018 Load Forecast included in the Application is an energy forecast only. The June 2019 Load Forecast includes a capacity (peak) load forecast, which is provided in this appendix.

1.1. Peak Demand is the Maximum Expected Amount of Electricity Consumed in a Single Hour

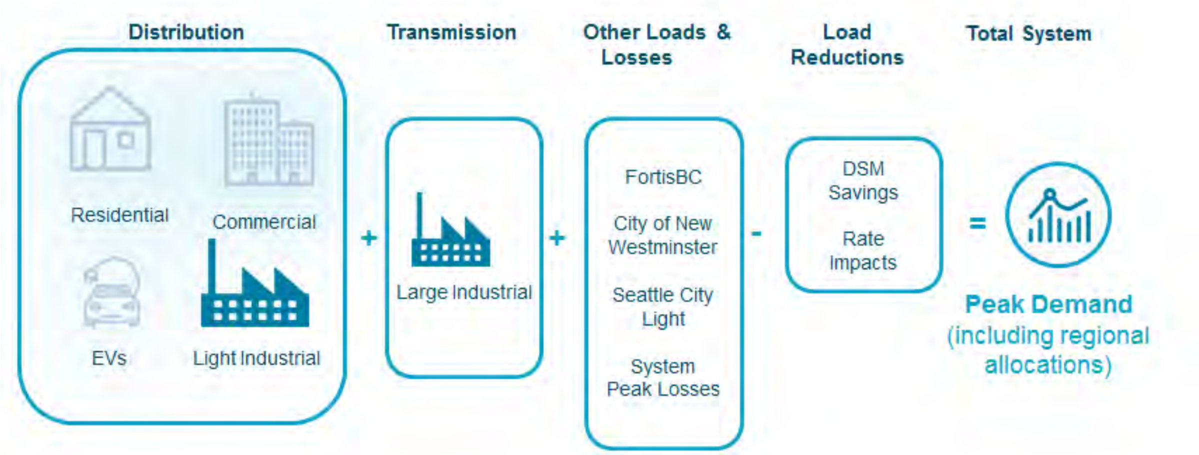
BC Hydro's peak demand is defined as the maximum expected amount of electricity consumed in a single hour under an average cold temperature assumption.
BC Hydro is a winter peaking utility, as our demand is more sensitive to colder temperatures than warmer temperatures. The total BC Hydro system typically reaches its annual peak on a cold winter day between 5:00 p.m. and 6:00 p.m. while Vancouver Island has a morning and an evening peak, as residential space heating is a larger component of Vancouver Island load. The Integrated System peak demand is the peak demand of all BC Hydro's customers as well as the peak demands from the other utilities served by BC Hydro and system transmission losses.

The total integrated system peak demand (Peak Demand) is constructed by:

- Adding distribution and transmission peak forecasts, peak demand provided by BC Hydro to other utilities, and system losses; and
- Subtracting DSM savings and rate impacts.

The build-up of the total system peak forecast is shown in Figure B-1 below.

Figure B-1 The building blocks of the Peak Demand



The following sub-sections provide further details on the purpose of the Peak Load Forecast and the main components of the total system peak demand. As explained further below, the effects of a more moderate rate of anticipated peak load growth are already reflected in the fiscal 2020 to fiscal 2024 Capital Plan included in the Application.

1.2. Peak Load Forecast Informs BC Hydro's Capital Planning

The peak demand forecast informs BC Hydro's capital planning cycles. As an updated peak demand forecast was not available when the fiscal 2020 to fiscal 2024 Capital Plan was being finalized and actual substation load (**MVA**) growth was moderating, BC Hydro reduced the overall growth related substation and distribution capital expenditures in the Fiscal 2020 to Fiscal 2024 Capital Plan, which formed the basis for the capital expenditures in the Test Period.

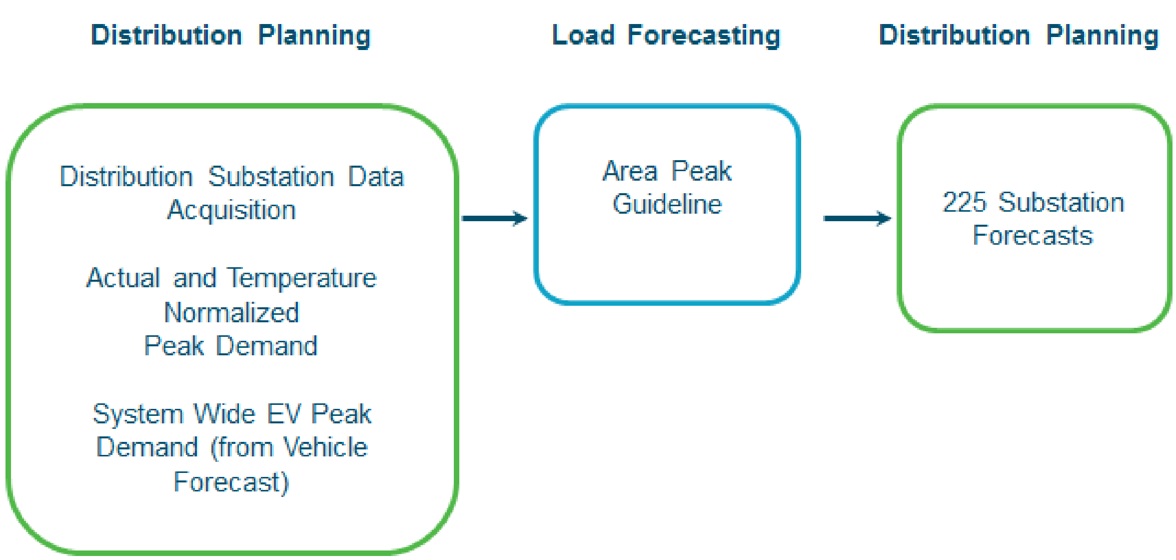
BC Hydro's response to BCUC IR 1.108.1.2 provided a list of projects that were deferred or cancelled as a result of the expected change in the load forecast. As discussed in BC Hydro's response to BCUC IR 1.111.1, growth investments support system expansions and reinforcements required to reliably serve new and existing customers and are not solely driven by changes in the load forecast.

1.3. Distribution Peak Methodology

The largest component of the Peak Demand is the total system coincident distribution peak. The distribution peak is the total peak demand for all distribution substations, including distribution losses, coincident with (i.e., at the time) when our system is reaching the highest demand. The individual substation peak forecasts are aggregated into BC Hydro's four service regions and then aggregated to a single total distribution peak for the system.

Figure B-2 below shows the main stages of the distribution peak forecast process. This methodology applies to only the first 11 years of the distribution peak forecast because a substation forecast for planning purposes is only developed for that timeframe. For the remaining nine years, the distribution peak growth is tied directly to the growth in the distribution energy forecast.

Figure B-2 Distribution Peak Forecast Process



The distribution peak process starts with the historical substation data collection and analysis. Temperature adjusted peak demands are estimated for each substation. In addition, a mid forecast of peak demand from Electric Vehicles (**EVs**) is developed using the number of EVs, consistent with the mid energy forecast.

A mid guideline forecast is developed using deterministic and econometric methods with various inputs, including:

- Historical temperature normalized substation peak demands;
- Rate impacts;
- Residential account forecasts; and
- Distribution energy forecasts from BC Hydro's end use model projections.

Other adjustments are made using peak load projections for emerging sectors, including EVs, cannabis and cryptocurrency.

Using the 15 sub region guidelines, mid substation forecasts and high substation forecasts are developed for the first 10 years of the forecast.[1] The mid substation forecasts are aggregated into four regions and coincidence factors are applied to develop regional and a total system coincident distribution peak demand. A peak demand forecast for EVs is developed with a separate model and included in the peak guidelines and the substation forecasts.

1.3.1. EV Peak Methodology

The EV peak model is a simulation model that has several inputs including the total annual number of EVs, daily distance travelled, EV efficiency, power of the charging equipment in kW and a charging time profile. These inputs are used in the simulation

1 BC Hydro's response to BCOAPO IR 2.101.1 provides additional details for the development of the substation and guideline forecast.

model to determine an EV daily peak shape, which is used to estimate the EV impact on BC Hydro's system coincident peak demand.

1.3.2. Transmission Peak Methodology

The second largest component of the Peak Demand is the coincident transmission peak demand. The transmission peak demand is the total coincident peak demand of all large industrial customers connected at transmission voltage. The drivers of the Large Industrial sector energy forecast generally also apply to the development of peak forecasts.

2.1.3 Other Utilities Peak Methodology

The third largest component of the Peak Demand is the other loads which includes sales to other utilities such as FortisBC Electric and Seattle City Light, the supply of electricity to Hyder, Alaska and two substations for the City of New Westminster as well as transmission system peak losses. The forecast for FortisBC Electric is based on the contract for power between BC Hydro and FortisBC Electric. The forecasts for Seattle City Light and Hyder are based historical trends. The forecast for the City of New Westminster is based on historical peak demand trends, supplemented by new incremental loads as provided by the City of New Westminster. Historical hourly data is used to estimate peak losses as a percentage of the total domestic peak at the time when BC Hydro's system is peaking.

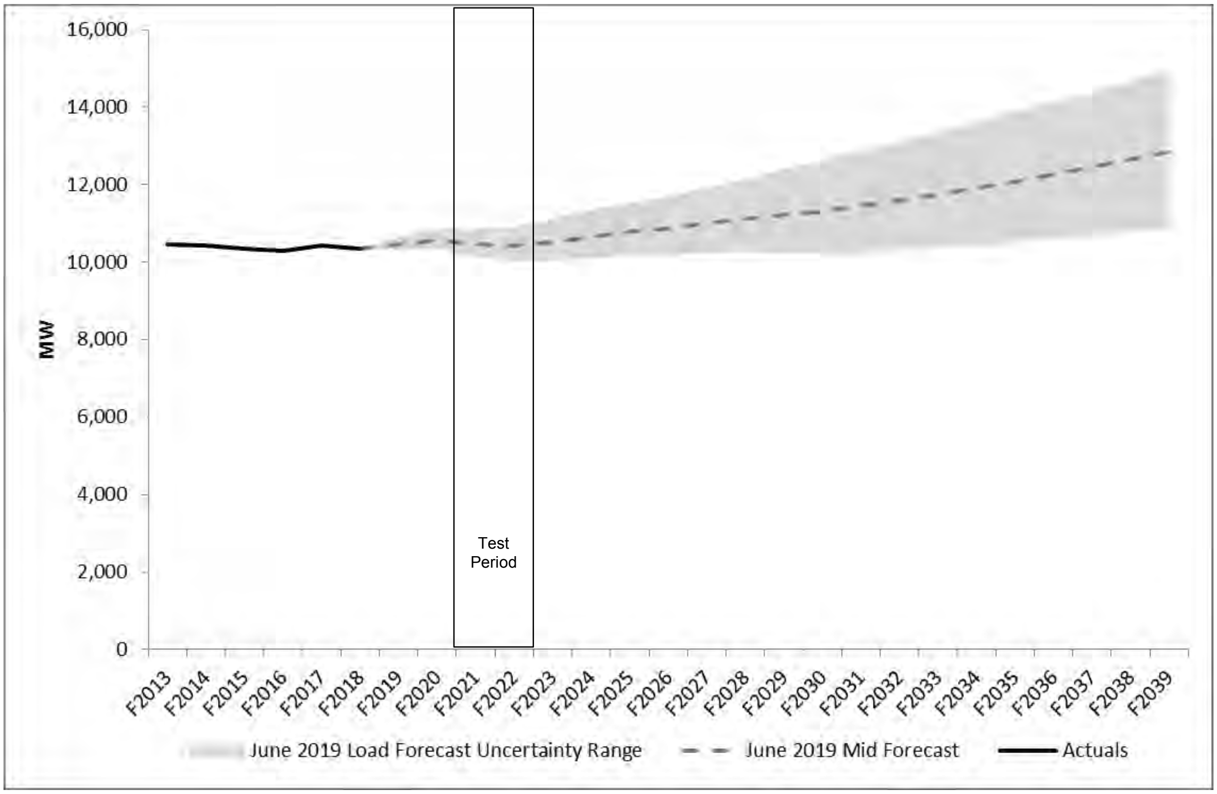
1.3.3. Subtraction of DSM and Rate Impacts

Consistent with the development of the energy forecast, load reductions are included in the peak demand forecast for rate impacts and DSM savings. The elasticity of -0.1 that is used to determine the rate impacts for energy is also used to determine the rate impacts for peak demand. As discussed further in section 3.2.6.2 of Chapter 3 of the Application, this elasticity assumption has been informed by an electricity price elasticity study conducted by DNV GL, which is provided as Appendix Q of the Application.

1.4. Total Integrated System Peak Forecast Results

The Total Integrated (mid) June 2019 System Peak Forecast after Demand-Side Management (**DSM**) savings expects growth in peak demand of approximately 1.0 per cent per year over the next 20 years.

Figure B-3 Total Integrated System Peak Forecast June 2019 Forecast



BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application

Twenty-Year Load Forecast

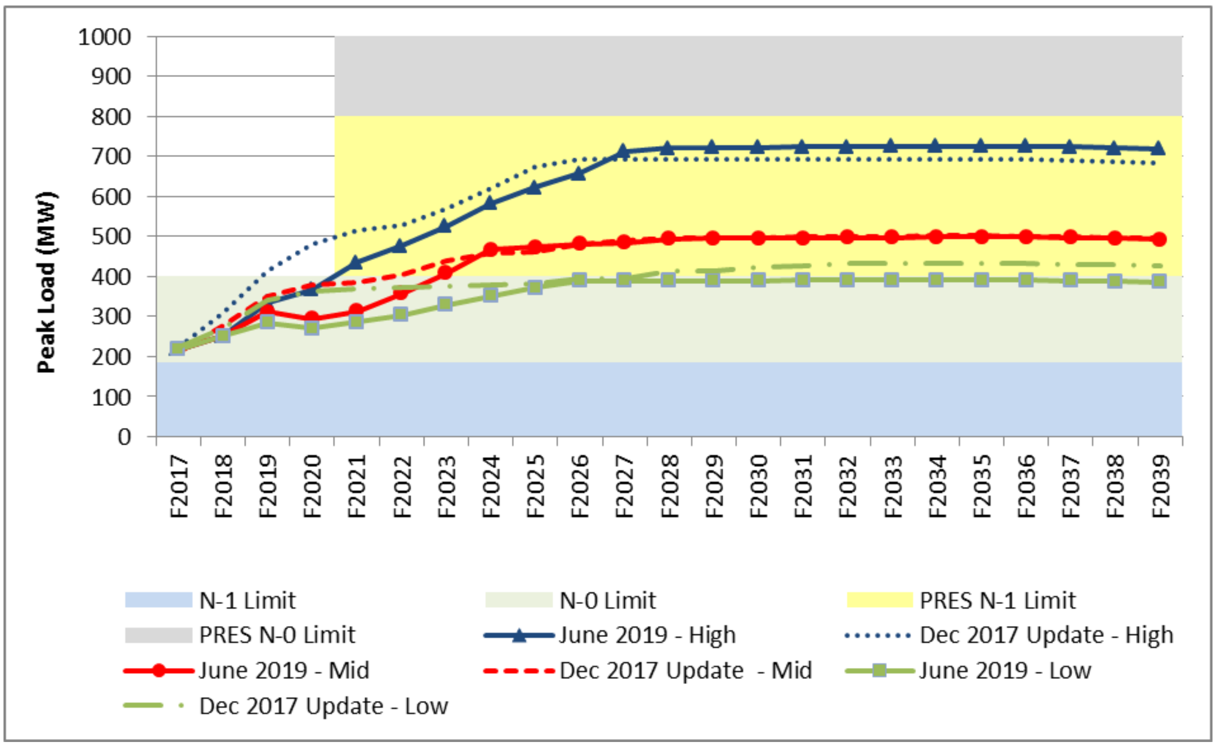
Appendix C

South Peace Region Forecast

In response to a commitment made in BC Hydro's response to BCUC IR 1.119.4, this appendix provides an update to the South Peace Region forecast for the area serviced by the Peace Region Electricity Supply Project (**PRES)**.

Figure C-1 below provides the June 2019 Load Forecast (mid, high and low), relative to the December 2017 update to the May 2016 Load Forecast, which was used to select a preferred transmission solution for the PRES project from a variety of alternatives.

Figure C-1 South Peace Region Load Forecasts June 2019 and December 2017 Update



Overall, the June 2019 forecast is similar to the December 2017 forecast.

In the short-term, the June 2019 mid forecast is lower than the December 2017 forecast primarily due to a decline in expected operating rates for some plants as a result of lower production levels. However, over the medium term, production levels are expected to increase to plant capacity.

The June 2019 high case is higher in the medium to long-term due to increased electrification assumptions in the Goundbirch area as a result of LNG development. The June 2019 low case is lower in the medium to long-term due to lower assumed plant operating levels.

BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application

Twenty-Year Load Forecast

Appendix D

Load Resource Balance Tables

In response to a commitment made in BC Hydro's response to BCUC IR 1.15.3, this appendix provides an updated planning Load Resource Balance (**LRB**) based on the June 2019 Load Forecast.

The following updates have been included:

- The load forecast has been updated from the adjusted May 2016 Load Forecast to the June 2019 Load Forecast;
- The IPP forecast has been updated from November 2018 to June 2019, and is consistent with the IPP forecast vintage used in the Evidentiary Update; and
- The assumption for the in-service date of Revelstoke Unit 6 (which is included as a planned resource) has changed from fiscal 2030 to fiscal 2036.

Table D-1 and Table D-2 below show the energy and capacity Load Resource Balance, respectively, before planned resources. Table D-3 and Table D-4 below show the energy and capacity Load Resource Balance, respectively, after planned resources.

Table D-1 Planning View of Energy Load Resource Balance Based on Existing and Committed Resources

	(GWh)		F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
	Existing and Committed Heritage Resources																				
1	Heritage Resources (including Site C)	(a)	46,916	46,916	46,916	47,282	50,808	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202
2	***Existing and Committed IPP Resources***	(b)	16,359	16,227	14,193	13,783	13,505	13,224	13,115	13,008	12,542	11,770	11,228	10,880	10,671	10,366	9,664	8,136	7,684	7,511	7,180
3	**Total Supply (Planning View)**	(c) = a + b	63,275	63,143	61,109	61,064	64,313	65,426	65,317	65,210	64,744	63,972	63,430	63,082	62,873	62,568	61,866	60,338	59,886	59,713	59,382
	Demand - Integrated System Total Gross Requirements																				
4	June 2019 Mid Load Forecast Before DSM	(d)	(60,738)	(60,688)	(61,759)	(63,383)	(64,993)	(66,144)	(67,358)	(68,011)	(68,741)	(69,291)	(69,913)	(70,537)	(71,244)	(71,932)	(72,645)	(73,350)	(74,097)	(74,827)	(75,551)
	Existing and Committed Demand Side Management & Others Measures																				
5	F19 DSM Portfolio Savings (F20-F21 RRA)		695	686	679	676	665	657	654	650	638	622	613	593	572	505	434	420	411	406	401
6	F20+ Codes & Standards (F20-F21 RRA) plus Voltage and VAR Optimization		615	964	1,235	1,482	1,713	1,920	2,108	2,271	2,427	2,584	2,726	2,856	2,982	3,110	3,239	3,367	3,494	3,622	3,750
7	Sub-total	(e)	1,310	1,650	1,914	2,158	2,378	2,577	2,762	2,921	3,066	3,206	3,339	3,448	3,555	3,615	3,674	3,787	3,906	4,028	4,151
8	**Surplus / (Deficit)**	(f) = c + d + e	**3,847**	**4,105**	**1,264**	**(161)**	**1,697**	**1,859**	**720**	**120**	**(932)**	**(2,113)**	**(3,143)**	**(4,006)**	**(4,816)**	**(5,748)**	**(7,105)**	**(9,225)**	**(10,305)**	**(11,086)**	**(12,019)**
9	**Surplus / Deficit as % of Net Load**		**106%**	**107%**	**102%**	**100%**	**103%**	**103%**	**101%**	**100%**	**99%**	**97%**	**95%**	**94%**	**93%**	**92%**	**90%**	**87%**	**85%**	**84%**	**83%**
10	**Small Gap Surplus / (Deficit)**		**5,728**	**6,344**	**3,965**	**3,011**	**5,069**	**5,423**	**4,716**	**4,346**	**3,970**	**3,222**	**2,425**	**1,733**	**1,029**	**216**	**(999)**	**(3,081)**	**(4,146)**	**(4,890)**	**(5,847)**
11	**Large Gap Surplus / (Deficit)**		**1,672**	**1,476**	**(1,927)**	**(3,887)**	**(2,270)**	**(2,347)**	**(3,944)**	**(4,820)**	**(6,616)**	**(8,280)**	**(9,561)**	**(10,672)**	**(11,588)**	**(12,680)**	**(14,178)**	**(16,365)**	**(17,507)**	**(18,314)**	**(19,289)**

Table D-2 Peak Capacity Load Resource Balance Based on Existing and Committed Resources

	(MW)		F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
	Existing and Committed Heritage Resources																				
1	Heritage Hydroelectric (including Site C)	(a)	11,588	11,588	11,528	11,588	12,319	12,319	12,676	12,676	12,676	12,676	12,676	12,262	12,262	12,733	12,733	12,733	12,733	12,733	12,733
2	***Existing and Committed IPP Resources***	(b)	1,458	1,486	1,211	1,200	1,138	1,106	1,106	1,093	1,056	924	888	884	861	810	566	493	458	424	423
3	14% of Supply Requiring Reserves - excl. Rio Tinto Alcan and FortisBC	(c)	(1,797)	(1,793)	(1,746)	(1,752)	(1,853)	(1,849)	(1,899)	(1,897)	(1,892)	(1,873)	(1,868)	(1,810)	(1,806)	(1,865)	(1,862)	(1,852)	(1,847)	(1,842)	(1,842)
4	**Effective Load Carrying Capability**	(d) = a + b + c	11,249	11,281	10,993	11,035	11,604	11,577	11,884	11,872	11,840	11,727	11,695	11,336	11,316	11,678	11,437	11,374	11,344	11,315	11,315
	Demand - Integrated System Total Gross Requirements																				
5	June 2019 Mid Load Forecast Before DSM	(e)	(10,870)	(10,887)	(11,054)	(11,264)	(11,463)	(11,579)	(11,768)	(11,906)	(12,059)	(12,189)	(12,343)	(12,508)	(12,689)	(12,881)	(13,085)	(13,296)	(13,517)	(13,743)	(13,974)
	Existing and Committed Demand Side Management & Others Measures																				
6	F19 DSM Portfolio Savings (F20-F21 RRA)		128	126	124	123	120	117	116	114	111	108	106	103	99	92	84	82	80	80	78
7	F20+ Codes & Standards (F20-F21 RRA) plus Voltage and VAR Optimization		129	198	246	289	327	361	391	417	441	465	486	505	523	546	569	592	615	638	662
8	Sub-total	(f)	257	324	371	411	447	479	507	532	553	573	592	607	622	638	653	674	696	718	739
9	**Surplus / (Deficit)****	(g) = d + e + f	**636**	**718**	**309**	**183**	**588**	**476**	**623**	**497**	**334**	**111**	**(56)**	**(565)**	**(751)**	**(565)**	**(995)**	**(1,248)**	**(1,477)**	**(1,710)**	**(1,920)**
10	**Surplus / Deficit as % of Net Load ****		**106%**	**107%**	**103%**	**102%**	**105%**	**104%**	**106%**	**104%**	**103%**	**101%**	**100%**	**95%**	**94%**	**95%**	**92%**	**90%**	**88%**	**87%**	**85%**
11	**Small Gap Surplus / (Deficit)****		**1,062**	**1,151**	**835**	**811**	**1,286**	**1,218**	**1,460**	**1,408**	**1,403**	**1,299**	**1,228**	**813**	**717**	**1,002**	**684**	**533**	**407**	**288**	**185**
12	**Large Gap Surplus / (Deficit)****		**332**	**264**	**(244)**	**(458)**	**(91)**	**(273)**	**(242)**	**(450)**	**(783)**	**(1,143)**	**(1,406)**	**(2,012)**	**(2,272)**	**(2,172)**	**(2,686)**	**(3,009)**	**(3,305)**	**(3,596)**	**(3,863)**

Table D-3 Planning View of the Energy Load Resource Balance After Planned Resources

	(GWh)		F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
1	***Existing and Committed Heritage Resources (incl. Site C)***	(a)	46,916	46,916	46,916	47,282	50,808	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202
2	***Existing and Committed IPP Resources***	(b)	16,359	16,227	14,193	13,783	13,505	13,224	13,115	13,008	12,542	11,770	11,228	10,880	10,671	10,366	9,664	8,136	7,684	7,511	7,180
	Future Supply-Side Resources																				
3	IPP Renewals		1,058	1,280	3,270	3,628	3,845	4,124	4,208	4,291	4,660	5,154	5,624	5,826	5,951	6,188	6,832	8,123	8,550	8,723	9,048
4	Expected SOP Projects and other First Nations Commitments		27	182	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226
5	Rev 6		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	26	26	26
6	Sub-total	(c)	1,085	1,462	3,496	3,854	4,071	4,350	4,434	4,517	4,886	5,380	5,850	6,052	6,177	6,414	7,058	8,360	8,802	8,975	9,300
7	**Total Supply (Planning View)**	(d) = a + b + c	64,360	64,604	64,606	64,919	68,384	69,775	69,750	69,727	69,630	69,353	69,280	69,134	69,050	68,982	68,924	68,698	68,688	68,688	68,681
	Demand - Integrated System Total Gross Requirements																				
8	June 2019 Mid Load Forecast Before DSM	(e)	(60,738)	(60,688)	(61,759)	(63,383)	(64,993)	(66,144)	(67,358)	(68,011)	(68,741)	(69,291)	(69,913)	(70,537)	(71,244)	(71,932)	(72,645)	(73,350)	(74,097)	(74,827)	(75,551)
	Existing and Committed Demand Side Management & Others Measures																				
9	F19 DSM Portfolio Savings (F20-F21 RRA)		695	686	679	676	665	657	654	650	638	622	613	593	572	505	434	420	411	406	401
10	F20+ Codes & Standards (F20-F21 RRA) plus Voltage and VAR Optimization		615	964	1,235	1,482	1,713	1,920	2,108	2,271	2,427	2,584	2,726	2,856	2,982	3,110	3,239	3,367	3,494	3,622	3,750
	Planned Demand Side Management Measures																				
11	F20+ Rates (F20-F21 RRA)		381	569	698	832	954	1,070	1,188	1,298	1,398	1,493	1,512	1,517	1,562	1,592	1,619	1,631	1,630	1,624	1,615
12	F20+ Programs (F20-F21 RRA)		128	144	149	145	142	140	139	138	137	137	137	137	136	136	136	136	135	135	135
13	Sub-total	(f)	1,819	2,363	2,760	3,135	3,474	3,788	4,088	4,357	4,600	4,835	4,988	5,102	5,253	5,344	5,428	5,554	5,672	5,787	5,901
14	**Surplus / (Deficit)**	(g) = d + e + f	**5,441**	**6,280**	**5,607**	**4,671**	**6,864**	**7,419**	**6,480**	**6,072**	**5,489**	**4,897**	**4,355**	**3,700**	**3,059**	**2,395**	**1,707**	**902**	**263**	**(351)**	**(969)**
15	**Surplus / Deficit as % of Net Load**		**109%**	**111%**	**110%**	**108%**	**111%**	**112%**	**110%**	**110%**	**109%**	**108%**	**107%**	**106%**	**105%**	**104%**	**103%**	**101%**	**100%**	**99%**	**99%**
16	**Small Gap Surplus / (Deficit)**		**7,272**	**8,448**	**8,224**	**7,746**	**10,128**	**10,864**	**10,345**	**10,156**	**10,240**	**10,070**	**9,760**	**9,275**	**8,737**	**8,188**	**7,640**	**6,871**	**6,248**	**5,671**	**5,029**
17	**Large Gap Surplus / (Deficit)**		**3,215**	**3,580**	**2,332**	**848**	**2,789**	**3,094**	**1,685**	**990**	**(347)**	**(1,432)**	**(2,226)**	**(3,129)**	**(3,880)**	**(4,708)**	**(5,538)**	**(6,412)**	**(7,114)**	**(7,754)**	**(8,412)**

Table D-4 Peak Capacity Load Resource Balance After Planned Resources

	(MW)		F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
	Existing and Committed Heritage Resources																				
1	Heritage Hydroelectric	(a)	11,588	11,588	11,528	11,588	12,319	12,319	12,676	12,676	12,676	12,676	12,676	12,262	12,262	12,733	12,733	12,733	12,733	12,733	12,733
2	***Existing and Committed IPP Resources***	(b)	1,458	1,486	1,211	1,200	1,138	1,106	1,106	1,093	1,056	924	888	884	861	810	566	493	458	424	423
	Future Supply-Side Resources																				
3	IPP Renewals		117	132	407	416	425	454	454	465	488	621	639	642	656	693	938	979	1,014	1,048	1,048
4	Expected SOP Projects and other First Nations Commitments		3	17	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
5	REV 6		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	488	488	488	488
6	Sub-total	(c)	120	148	426	435	444	473	473	484	507	639	658	661	675	712	957	1,486	1,521	1,555	1,555
7	14% of Supply Requiring Reserves - excl. Rio Tinto Alcan and FortisBC	(d)	(1,813)	(1,813)	(1,805)	(1,813)	(1,915)	(1,915)	(1,965)	(1,965)	(1,963)	(1,963)	(1,960)	(1,902)	(1,901)	(1,965)	(1,965)	(2,029)	(2,029)	(2,029)	(2,029)
8	**Effective Load Carrying Capability**	(e) = a+b+c+d	11,352	11,409	11,359	11,409	11,986	11,984	12,291	12,288	12,277	12,277	12,261	11,905	11,897	12,291	12,291	12,683	12,683	12,683	12,683
	Demand - Integrated System Peak																				
9	June 2019 Mid Load Forecast Before DSM	(f)	(10,870)	(10,887)	(11,054)	(11,264)	(11,463)	(11,579)	(11,768)	(11,906)	(12,059)	(12,189)	(12,343)	(12,508)	(12,689)	(12,881)	(13,085)	(13,296)	(13,517)	(13,743)	(13,974)
	Existing and Committed Demand Side Management & Others Measures																				
10	F19 DSM Portfolio Savings (F20-F21 RRA)		128	126	124	123	120	117	116	114	111	108	106	103	99	92	84	82	80	80	78
11	F20+ Codes & Standards (F20-F21 RRA) plus Voltage and VAR Optimization		129	198	246	289	327	361	391	417	441	465	486	505	523	546	569	592	615	638	662
	Planned Demand Side Management Measures																				
12	F20+ Rates (F20-F21 RRA)		57	87	108	129	148	166	183	199	213	226	230	232	238	244	250	254	256	257	257
13	F20+ Programs (F20-F21 RRA)		15	17	17	17	16	16	15	15	15	15	15	14	14	14	14	14	14	14	14
14	Sub-total	(g)	330	427	496	557	611	660	705	745	781	813	836	854	874	896	918	942	966	989	1,011
15	**Surplus / (Deficit)****	(h) = e + f + g	**812**	**949**	**801**	**703**	**1,135**	**1,065**	**1,228**	**1,127**	**999**	**901**	**754**	**250**	**81**	**306**	**123**	**329**	**131**	**(71)**	**(281)**
16	**Surplus / Deficit as % of Net Load ****		**108%**	**109%**	**108%**	**107%**	**110%**	**110%**	**111%**	**110%**	**109%**	**108%**	**107%**	**102%**	**101%**	**103%**	**101%**	**103%**	**101%**	**99%**	**98%**
17	**Small Gap Surplus / (Deficit)****		**1,229**	**1,370**	**1,312**	**1,314**	**1,814**	**1,786**	**2,044**	**2,015**	**2,042**	**2,064**	**2,013**	**1,602**	**1,524**	**1,848**	**1,776**	**2,083**	**1,989**	**1,900**	**1,798**
18	**Large Gap Surplus / (Deficit)****		**499**	**483**	**233**	**45**	**436**	**295**	**341**	**157**	**(144)**	**(378)**	**(621)**	**(1,223)**	**(1,465)**	**(1,327)**	**(1,594)**	**(1,459)**	**(1,724)**	**(1,984)**	**(2,251)**