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February 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: 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 (the Application)

BC Hydro writes to provide as Exhibit B-44 its responses to all remaining undertakings resulting from the Oral Hearing of January 20 to January 24, 2020.

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 UNDERTAKING NO. 11

HEARING DATE: January 23, 2020

REQUESTOR: BCUC, Mr. Miller

TRANSCRIPT REFERENCE: Volume 8A, Page 1172, line 20 to Page 1173, line 20

TRANSCRIPT EXCERPT:

MR. MILLER: Q And actually the letter is found at page 68 of the witness aid.

Do you have any idea of what the dollar amount impact to the revenue requirement is as a result of these changes for the six technology projects?

MR. LAYTON: A I do not offhand. You have to do some math to assess that.

MR. MILLER: So perhaps you can do this in an undertaking. Can you provide the impact to the revenue requirement broken down by expense categories such as amortization expense, financing charges, and operating expenses? Is that possible?

MR. LAYTON: A I think so. If I can clarify, Mr. Miller, I think what we're saying here is that we're seeking not to impact the revenue requirement on the capital side. So to be responsive to your question I think what it would show is that these project in isolation, how much of the expected incremental costs related to these updates in this letter. Would that be responsive to your question?

MR. MILLER: Q Staff would like to know what the impact would have been had you chosen to include in the revenue requirement.

MR. LAYTON: A Thank you. I think we are saying the same thing.

QUESTION:

What would be the impact to the revenue requirement of the six technology projects mentioned in Exhibit B-29 broken down by expense category such as amortization, finance charges and operating costs, had BC Hydro included them in the revenue requirement and not offset the cost?

RESPONSE:

BC Hydro notes that in Exhibit B-29 we stated that any changes in capital expenditures or additions (including resulting amortization) for the Test Period, associated with these updates, will be managed within the amounts that were included in the Application. Also, BC Hydro will manage any changes in the operating costs within its operating budget for the Test Period.

For the purpose of this analysis, BC Hydro assumes that the impact of the changes are incremental to the capital and operating budgets included in the Application. The estimated incremental impact of the six technology projects included in Exhibit B-29 on the Test Period revenue requirement is shown in the table below by cost category.

Estimated cost increase/(decrease) - $ millions	Amortization	Operating Expenses	Finance Charges	Total
1. Energy Management System Upgrade (1)	-	0.1	-	0.1
2. Advanced Distribution Management System (2)	-	0.2	-	0.2
3. Contact Centre Technology Foundation (3)	(0.6)	0.8	(0.1)	0.1
4. Next generation Desktop (Windows 10) (4)	(0.2)	(1.2)	-	(1.4)
5. Microsoft Enterprise License Agreement (5)	4.4	-	-	4.4
6. IT Service Management Toolset (6)	-	-	0.2	0.2
Net Increase/(Decrease)	3.6	(0.1)	0.1	3.6

Notes:

(1) EMS (2) ADMS	These two projects were not originally planned during the Test Period. • These two projects have in-service date forecasts of fiscal 2023, so there is no expected amortization impact in the test period. • The expected increase in operating expenses relates to the non-capital project expenditures during the Test Period. • The expected impact to finance charges is nil as interest during construction is capitalized on the project's capital expenditures during the Test Period.
(3) Contact Centre Technology Foundation	• This project was originally planned to be in-service during fiscal 2021. In-service date forecast has shifted to fiscal 2022, resulting in a reduction to expected amortization expense during the Test Period. • The expected increase in operating expenses relates to the non-capital project expenditures during the Test Period. • As the in-service date is later than originally planned, expected finance charges on constructed assets is reduced in the Test Period.
(4) Next Generation Desktop (Windows 10)	• This project was originally planned to be partially in-service during fiscal 2020 and fully in-service in fiscal 2021. In-service date forecast and start of amortization is now fiscal 2021, resulting in a reduction to expected amortization expense in the Test Period. • Reduction in expected operating expenses due to project activities originally classified as operating were reclassified as capital. The expected impact to finance charges (expense) is nil as interest during construction is capitalized on the project's capital expenditures.
(5) Microsoft Enterprise License Agreement	• This project was originally planned with capital expenditures and capital additions of $4.0 million. The increase in expected amortization expense is a result of the $19.5 million capital addition in fiscal 2020 versus $4.0 million in the Test Period. • The expected impact on finance charges is negligible during the Test Period.
(6) IT Service Management Toolset	• The expected amortization and operating expense impacts in the Test Period are negligible. • The expected impact to finance charges is due to the increase in project-related pre-paid configuration operating expenditures during the Test Period.

The impact of the six technology projects on the revenue requirement, if not managed within the amounts included in the Application, would have been an estimated increase of $3.6 million. This is primarily due to the amortization of the Microsoft Enterprise License Agreement.

BC HYDRO UNDERTAKING NO. 12

HEARING DATE: January 23, 2020

REQUESTOR: BCUC, Mr. Miller

TRANSCRIPT REFERENCE: Volume 8A, Page 1197, line 5 to Page 1198, line 13

TRANSCRIPT EXCERPT:

MR. MILLER: Q Can you turn to the Panel IR 2.17.4 of Exhibit B31? Let me know when you're there.

MR. LAYTON: A We're there, thank you.

MR. MILLER: Q I understand that IR response to make two points. The first is the effective interest rate is 3.02 percent and the hedged interest rate is 3.36 percent. Is that correct?

MR. LAYTON: A Yes.

MR. MILLER: And so if you go to the column that says settlement value, which is I think the fifth or the sixth column on the Table to Panel IR 2.17.3, or the attachment. It's the same table I was asking you what do the rates represent on the right side, right-hand column.

MR. LAYTON: A And sorry, which line are you one?

MR. MILLER: Q The line is "Hedges placed during 2018" and particularly "2017-9-28". There the rate is 16.7. That doesn't seem to match. Or sorry, 2.5 Sorry, on the right-hand side, 2.57. Excuse me, the table that says on the right-hand table -- sorry, right-hand column for the same timeframe.

MR. MILLER:The query from staff is, this doesn't seem to match either the effective interest rate or the hedged interest rate provided in the response to Panel IR 2.17.4. Do you have any comment on that?

MR. LAYTON: A I'm just going to take a moment and see if I can obtain the answer.

MR. MILLER: Q Yes.

MR. LAYTON: A Mr. Miller, I absolutely understand your question and what staff is seeking confirm, I can't immediately provide an answer to that, but I'm happy to undertake to do so.

QUESTION:

Please reconcile any discrepancies regarding effective interest rates or hedged interest rates between BC Hydro's responses to BCUC Panel IR 2.17.3 and 2.17.4.

RESPONSE:

The contract rate of 2.57 per cent referred to in Attachment 1 to BC Hydro's response to BCUC Panel IR 2.17.3 represents the contract rate of the hedge. This hedge is a bond lock and its contract rate is based on the yield on the Government of Canada bond when the hedge was entered into. The contract rate is the rate that is used to value the hedge (i.e., to determine the mark-to-market gain or loss at a point in time). The Government of B.C. issues debt on behalf of BC Hydro, and the interest rate is comprised of two main components. The first component is the yield (or interest rate) on the Government of Canada bond.

The second component is the Government of B.C.'s credit spread. The credit spread is the difference in yield on the Government of Canada bond and on the Government of B.C. bond on debt of the same maturity. The difference is attributable to credit quality. In other words, the Government of Canada is able to issue debt at lower costs than the Government of B.C.

Therefore, the contract rate of 2.57 per cent is one of the inputs used in arriving at the hedged interest rate of 3.36 per cent referenced in BC Hydro's response to BCUC Panel IR 2.17.4. The spread is the other input and is added to the contract rate to arrive at the hedged interest rate of 3.36 per cent (i.e., contract rate of 2.57 per cent plus a spread of 0.79 per cent equals the hedged interest rate of 3.36 per cent).

The 3.36 per cent hedged interest rate represents the approximate interest rate that BC Hydro locked in for its planned future debt issuance in the example shown in BC Hydro's response to BCUC Panel IR 2.17.4. The hedged rate, as opposed to the contract rate, was used in that response to provide an apples to apples comparison of the hedged rate to the net effect of the effective yield on the actual debt issuance and the hedge loss.

When the debt was issued and the hedge was unwound, interest rates had fallen relative to when the hedge was entered into. This resulted in BC Hydro issuing the debt at a lower interest rate of 3.02 per cent (i.e., the effective interest rate noted in BC Hydro's response to BCUC Panel IR 2.17.4, which incorporates both the Government of Canada yield and the Government of B.C. spread). The interest savings were offset by the loss on the hedge as discussed in BC Hydro's response to BCUC Panel IR 2.17.4.

The interest rates referenced in BC Hydro's responses to BCUC Panel IRs 2.17.3 and 2.17.4 are correct. These interest rates relate to different components of BC Hydro's hedging activities.

BC HYDRO UNDERTAKING NO. 17

HEARING DATE: January 24, 2020

REQUESTOR: MOVEUP, Ms. S. Quail

TRANSCRIPT REFERENCE: Volume 9, Page 1407, line 10 to Page 1409, line 23

TRANSCRIPT EXCERPT:

MS. QUAIL: Q You're welcome. So looking at that second bullet point, FERC order number 842 and Hydro is developing its response, including engagement with transmission customers, interested parties. So my fist question regarding that order is in what way and to extent is this FERC rule requiring that newly connected generators have primary frequency response capability problematic for BC Hydro?

MS. MATTHEWS: A I mean one of the difficulties for having and replying to this is that no one on this panel is actually the ones who have the detailed knowledge of the OATT. And that had seemed to not be part of the scope so we haven't prepped to be really answering questions around the OATT.

MS. QUAIL: Q That's fair. Could we have an undertaking to provide a response?

MS. QUAIL: Q So I have just a few questions that flow from that that may also need to be undertakings. I'll put them and -- okay.

So my next question is what is the state of this capability? And that's the jargon, right? The capability, primary frequency response capability. What is the state of this capability for Existing IPP owned generators that are connected to BC Hydro's system? I imagine that's something to be answered by undertaking?

MS. QUAIL: Q Yes. Flowing from that, are the existing IPP owned generators that are connected to BC Hydro's system contributing to what FERC has identified as the deterioration of overall frequency response capability of interconnected systems? Is that a matter for undertaking?

MS. QUAIL: Q And then I have a final question, and I'm going to ask this question but if it is prejudicial to BC Hydro's legal position in other legal relationships, I understand if it needs to not be answered but I'll ask it in case it's fair game. And the question is, under the terms of the existing IPP EPAs does Hydro bear the risk of changes in FERC and other regulatory rules over the lifetime of the agreements? And I assume that's for undertaking as well.

QUESTION:

In what way and to what extent is FERC Order 842 requiring that newly connected generators have primary frequency response capability problematic for BC Hydro?

What is the state of this capability for existing IPP owned generators that are connected to BC Hydro’s system?

Are the existing IPP owned generators that are connected to BC Hydro's system contributing to what FERC has identified as the deterioration of overall frequency response capability of interconnected systems?

Under the terms of the existing IPP EPAs, does BC Hydro bear the risk of changes in FERC and other regulatory rules over the lifetime of the agreements?

RESPONSE:

FERC Order No. 842 reforms specifically add the requirement that both newly connected synchronous and non-synchronous generators must have primary frequency response capability. Previously, only synchronous generators were subject to this requirement. In FERC's view, recent technological advancements now enable non-synchronous generators (e.g., wind or solar) to have primary frequency response capability.

BC Hydro already requires comparable or superior primary frequency response capability requirements for interconnecting synchronous generators as part of its OATT generator interconnection business practice. These requirements form part of the technical requirements that are included in BC Hydro's Standard Generator Interconnection Agreement. The FERC reforms, if proposed by BC Hydro, approved by the BCUC and incorporated into the OATT, would add similar requirements for non-synchronous generators into the tariff.

Most existing IPP owned generators connected to the BC Hydro system have primary frequency response capability as required in their interconnection agreement with BC Hydro. The exception are existing wind and solar facilities in British Columbia, a few older IPPs, and some load displacement generators (e.g., at pulp mills). BC Hydro's overall frequency response capability has always been very good.

Accordingly, BC Hydro does not believe that IPPs connected to its system are materially contributing to the deterioration of the frequency response capability of the Western Interconnection. BC Hydro understands that, with its Order No. 842 reforms, FERC is targeting new, non-synchronous generators in U.S. jurisdictions that that have high and increasing penetration of wind, solar and other intermittent generation sources.

As discussed in BC Hydro's response to BCUC Panel IR 2.8.5.1 (attached), the specific reforms contained in FERC Order No. 842 are intended to be applicable to newly connected generators only, which means generators with existing Electricity Purchase Agreements (EPAs) will not be impacted. The FERC 842 reforms will, in some cases, reduce the risk to transmission providers by reducing the amount of primary frequency response they are required to provide to maintain reliability of their system.

However, as stated in BC Hydro's response to BCUC Panel IR 2.8.5.1, BC Hydro continues to monitor FERC Orders and make applications to the BCUC to amend its OATT when it believes those changes are appropriate in British Columbia. Such applications also keep the OATT aligned with the FERC pro forma OATT which allows Powerex to demonstrate to FERC that its comparability requirements are being met, which in turn allows Powerex to maintain its access to markets in the U.S. in order to generate Trade Income for the benefit of BC Hydro's ratepayers. The OATT is based on the FERC pro forma OATT. While it does not exactly mirror the pro forma, it is comparable, consistent with, or superior to the pro forma OATT.

British Columbia Utilities Commission Panel Information Request No. **2.8.5.1** Dated: **December 12, 2019** British Columbia Hydro & Power Authority Response issued **January 17, 2020**	Page 1 of 5
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-31**

8.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, pp. 9-1, 9-10; Exhibit B-5, BCUC IR 162.1; Exhibit B-12, BCUC IR 267.1; Exhibit B-19, p. 9; Appendix A, Schedule 3.4; Decision and Order G-40-19 to the FortisBC Inc. 2017 Cost of Service Analysis and Rate Design Application, dated February 25, 2019 (FBC 2017 COSA and RDA Decision), pp. 87–88
Cost allocations to generation, transmission and distribution

Page 9-1 of the Application states:

> The rates charged under the OATT [Open Access Transmission Tariff] are designed to collect the TRR, which is the sum of BC Hydro's net transmission function costs, as calculated using a cost of service methodology... consistent with the method used by the British Columbia Transmission corporation (BCTC) and the method approved in the BCUC's 1998 Decision accompanying Order No. G-43-98 related to BC Hydro's Application for Approval of Wholesale Transmission Services.

BC Hydro's response to BCUC IR 162.1 states "There have also been multiple OATT amendments over the years that have addressed additional specific OATT rates and rate design issues."

Page 87 of the FBC 2017 COSA and RDA Decision states:

> The appropriateness of rate harmonization in British Columbia has not been revisited in light of the fact that markets did not develop as expected as a result of deregulation of the industry around the time of Order No. G-12-99. These expected developments included significant retail access usage in B.C. and the formation of Regional Transmission Organizations (RTOs) within the Western Interconnection with centralized transmission planning and operations. These developments did not occur.

Page 88 of the FBC 2017 COSA and RDA Decision also states that "The Panel recommends that the BCUC establish a proceeding to inquire into the broader issues of transmission rate harmonization, with the involvement of transmission owners and transmission customers in the Province."

2.8.5 Please describe the general state of the BC energy industry and the North American market during 1998.

2.8.5.1 Please describe how each of the BC energy industry and the North American market has changed since that time. In your response, please discuss how the OATT amendments have addressed these changes, if any.

RESPONSE:

BC Hydro interprets the IR to be seeking background on the electricity industry as opposed to the "energy" industry, which would include all forms of energy. BC Hydro also interprets this question to be requesting information on the evolution of electricity markets in the Western Interconnection, and specifically to markets and transmission providers that are under the jurisdiction of the U.S. Federal Energy Regulatory Commission (FERC), or subject to its reciprocity, and comparable and non-discriminatory access requirements.

Continuing from the description of the electricity market in the 1990s in BC Hydro's response to BCUC Panel IR 2.8.5, wholesale transmission services markets continued to develop in the late 1990s and early 2000s. At that time, it was believed that the North American electric industry would continue the adoption of independence for transmission system operations and that Independent System Operators (ISOs) and/or Regional Transmission Organizations (RTOs) would become the norm across all regions.

In 2002, the Government of B.C. issued its 2002 Energy Plan, which established the province's electricity policy. This policy included that the private sector would build new generation and that BC Hydro would have a role in large hydroelectric projects in addition to maintaining and/or upgrading its existing facilities. The Energy Plan also sought to encourage private sector investment by ensuring fair, non-discriminatory access to the wholesale transmission grid, and to promote low electricity rates within the province by promoting trade opportunities in U.S. wholesale power markets.

The Government of B.C. enacted the *BC Hydro Public Power Legacy and Heritage Contract Act* (S.B.C. 2003, c. 86) to ensure BC Hydro remained publicly-owned and that BC Hydro ratepayers received the benefit of embedded low-cost resources.

The Government of B.C. also adopted the *Transmission Corporation Act* (S.B.C. 2003, c. 44) (TCA), which established the British Columbia Transmission Corporation (BCTC) as a separate corporation responsible for the operation and planning of the BC Hydro transmission facilities. It required BCTC to seek an order from the Commission approving its first schedule of rates on or before December 31, 2004. The formation of BCTC created an independent transmission provider that was intended to align with the Government of B.C.'s promotion and encouragement of new sources of power generation across British Columbia per the 2002 Energy Plan.

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BCTC submitted its application for an Open Access Transmission Tariff (OATT) to replace BC Hydro's Wholesale Transmission Service (WTS) tariff on August 3, 2004 and, as discussed in BC Hydro's response to BCUC IR 1.162.1, the OATT was approved in 2005 through BCUC Order No. G-58-05. The OATT met the requirements of the FERC as established by the WTS by maintaining comparability to FERC's *pro forma* OATT established under Order No. 888. It also affirmed or established key rate design concepts that continue to be used in determining BC Hydro's OATT rates.

In 2005, BCTC filed an application for approval of OATT amendments to provide dynamic scheduling of exports of energy and ancillary services from BCTC's Control Area which would enable its customers to participate on a dynamic basis (i.e., allowing changes to the energy schedule within a given period vs static schedules which were fixed for the period) in the California Independent System Operator (CAISO). The amendments were approved on a permanent basis through Order No. G-12-06 dated February 2, 2006.

In 2007, the Government of B.C. updated its electricity policy through Energy Plan 2007, which established an energy self-sufficiency requirement in British Columbia, including incremental electricity supply for insurance purposes. It also contemplated further investment in transmission infrastructure by BCTC to address congestion relief and required adoption of reliability standards. As included in BC Hydro's response to BCUC Panel IR 2.8.5.2, BC Hydro has continued to seek amendments to the OATT as required to align the OATT with the reliability standards as adopted in British Columbia.

FERC continued to respond to industry developments and in 2007, issued its Order No. 890, which sought to further reduce opportunities for undue discrimination and barriers to entry in the provision of transmission service. These reforms included: (i) standardization of Available Transfer Capability (ATC) calculations; (ii) requiring open and transparent local and regional transmission planning processes; (iii) eliminating artificial barriers to the use of the grid; (iv) addressing needs arising from the growth of clean energy resources such as wind power by establishing conditional firm service and reforming imbalance penalty frameworks; (v) strengthening compliance requirements and enforcement measures; and (vi) clarifying certain provisions of the *pro forma* OATT that had proven to be ambiguous.

BCTC reviewed Order No. 890 and submitted an application to the Commission on November 21, 2008 to address reforms to the FERC *pro forma* OATT as reformed by Orders No. 890, 890-A and 890-B, to the extent that these were relevant in British Columbia. As discussed in BC Hydro's response to BCUC IR 1.162.1, the OATT amendments were approved through BCUC Order No. G-102-09, including the establishment of short-term rate design principles.

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Expected developments regarding the further formation of ISOs or RTOs did not occur in the Western Interconnection and, in 2010, the Government of B.C. enacted the *Clean Energy Act* (S.B.C. 2010, c. 22), which, among other things, re-integrated BCTC into BC Hydro. As a result, BC Hydro took over responsibility for the OATT and assumed responsibility for planning and operation of the transmission system. BC Hydro applied to amend the OATT as required to assume the role of the Transmission Provider, and these amendments were approved through BCUC Order No. G-192-10.

With the issuance of Order No. 1000 in 2011, FERC further reformed the requirements for transmission planning and cost allocation to facilitate greater efficiencies in transmission planning. BC Hydro examined Order No. 1000 and engaged in a stakeholder process to evaluate and adopt related OATT reforms to the extent appropriate in British Columbia. On February 19, 2013, as part of a consolidated OATT Application, BC Hydro submitted proposed OATT amendments in response to FERC Order No. 1000. The amendments were approved by the BCUC through order No. G-59-13 on April 18, 2013.

The electric industry continued to evolve, most notably with substantial growth in the development of variable energy resources (VERs) in response to policies favouring renewable generation. These resources generate energy based on the availability of the sun or wind but do not include energy storage capability and hence have variability that is beyond the control of the facility owner or operator. To address the need to better integrate these variable resources, FERC issued Order No. 764 in 2012 with requirements that transmission providers (i) establish the functionality to offer intra-hour transmission scheduling at 15-minute intervals, in addition to existing hourly scheduling provisions; and, (ii) incorporate provisions into the *pro forma* OATT to require interconnection customers whose generating facilities are variable energy VERs to provide meteorological and forced outage data to the transmission provider for the purpose of power production forecasting. BC Hydro examined Order No. 764 and engaged in a stakeholder process to evaluate and adopt related OATT reforms to the extent appropriate in British Columbia. BC Hydro submitted its Order No. 764 Amendments Application on September 6, 2013. The amendments were approved through BCUC Order No. G-180-13 on October 31, 2013.

Market evolution continued to progress and on October 2, 2017, BC Hydro filed its Dynamic Scheduling Amendments Application, which sought to amend the dynamic scheduling provisions of the OATT that were originally approved in 2005 to improve flexibility and allow customer participation in new markets such as CAISO's Energy Imbalance Market. These amendments were approved through BCUC Order No. G-20-18 on January 26, 2018.

BC Hydro continues to monitor market evolution and FERC Orders and make applications to amend its OATT that it believes are appropriate in British

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Columbia. Such applications also keep the OATT aligned with the FERC *pro forma* OATT which allows Powerex to demonstrate to FERC that its comparability requirements are being met, which in turn allows Powerex to maintain its access to markets in the U.S. in order to generate Trade Income for the benefit of BC Hydro's ratepayers.

BC Hydro is currently developing its response to three recent FERC Orders, including engagement with transmission customers and interested parties. These are:

- **FERC Orders No. 845 and 845-A, which reform the generator interconnection procedures of FERC's *pro forma* OATT to improve certainty for interconnection customers, promote more informed interconnection decisions, and enhance the interconnection process;**
- **FERC Order No. 842, which amends FERC's *pro forma* OATT to require that newly connected generators have primary frequency response capability, which is intended to address deterioration of the overall frequency response capability of interconnected systems, such as the Western Interconnection; and**
- **FERC Orders No. 784 and 784-A which require amendment to transmission providers' ancillary service rate schedules to take into account the speed and accuracy of regulation resources in the determination of reserve requirements for Regulation and Frequency Response Service.**

BC HYDRO UNDERTAKING NO. 18

HEARING DATE: January 24, 2020

REQUESTOR: CEABC, Mr. D. Austin

TRANSCRIPT REFERENCE: Volume 9, Page 1418, lines 1 to 18

TRANSCRIPT EXCERPT:

MR. AUSTIN: Q Right. So what's the full cost to BC Hydro's customers of the John Hart project over 70 years.

MS. MATTHEWS: A So I don't know that answer offhand, but that answer would have been included -- or all of that information would have been included at the CPCN at the time that that was submitted.

MR. AUSTIN: Q Well, I participated in that CPCN project review and I don't remember it being presented in that manner, and I was just wondering if BC Hydro could undertake to present that cost.

THE CHAIRPERSON: I can see Mr. Ghikas is going to weigh in on this, but perhaps we could constrain this to someone could go back and look at what was in the original CPCN and if that information was in the CPCN, then, Mr. Austin, would that be all right?

MR. AUSTIN: Q Fine. Similarly, could they do that for Ruskin?

QUESTION:

Did the John Hart and Ruskin CPCN Applications provide calculations of net present value and levelized cost of energy over the life of the projects?

RESPONSE:

Both the John Hart and Ruskin CPCN Applications included calculations of project Net Present Values, and the levelized costs of energy from those facilities. In both cases, the analysis reflected costs over a term of 50 years, and included assumed maintenance and operating costs over that term. Capital overhead on the two projects was included in the Net Present Value calculations, but was excluded from the levelized costs in accordance with BC Hydro's standard practice for such calculations. These results were presented in Table 3-4 and Table 3-5 of the Ruskin CPCN Application, and Table 3-4 and Table 3-5 of the John Hart CPCN Application.

The Ruskin calculations did not reflect future capital maintenance costs which were not thought to be material relative to the project itself. The John Hart calculations did include costs for the seismic upgrades of the John Hart and

Strathcona Dams, as well as other work on the Campbell River system, as these costs were considered to be material.

The calculated values as presented in Table 3-4 and Table 3-5 of the Ruskin CPCN Application and Table 3-4 and Table 3-5 of the John Hart CPCN Application are provided below. They are based on Expected Cost Amounts and are in dollars as of the application dates.

	Net Present Value $ Millions	
	John Hart	**Ruskin**
Project Value Before Decomissioning Credit	**466**	**153**
Decommissioning Credit	**145**	**148**
Project Value After Decomissioing Credit	**612**	**301**

	Cost of Energy $ / MWh	
	John Hart	**Ruskin**
Gross Cost of Energy	**96.8**	**101.2**
Decommissioning Credit	**(13.6)**	**(33.7)**
	83.2	**67.5**
Capacity Credit	**(8.5)**	**(16.5)**
Net Cost of Energy	**74.7**	**50.9**

The application of a Decommissioning Credit on project Net Present Value and Levelized Cost of Energy recognizes the benefit of avoiding the cost of decommissioning large facilities and rehabilitating their footprints. These costs can be significant, even in the context of large projects like John Hart or Ruskin. Inclusion of decommissioning credits in project evaluation is standard practice in capital-intensive businesses, and is part of BC Hydro's normal project management practice. This analytical approach was accepted by the BCUC in both the John Hart and Ruskin CPCN proceedings.

The Capacity Credit recognizes the value of dependable capacity provided by dispatchable resources that include energy storage. That value is already reflected in the Project Value (gross) amount shown above. Applying this value to the calculation of the Levelized Cost of Energy makes that value more comparable to resources that do not provide dependable energy, either because they cannot be dispatched, or because of limits on their energy storage.

BC HYDRO UNDERTAKING NO. 20

HEARING DATE: January 24, 2020

REQUESTOR: BCUC, Commissioner Morton

TRANSCRIPT REFERENCE: Volume 9, Page 1582, lines 16 to 23

TRANSCRIPT EXCERPT:

THE CHAIRPERSON: Excuse me. And when it is available is that documentation public?

MS. DASCHUK: A That's a good question. Can I check on that?

THE CHAIRPERSON: Certainly, and perhaps you would also let me know whether it would be filed with the Commission when it was ready.

MS. DASCHUK: A Yes.

QUESTION:

Will BC Hydro's Diesel Reduction Strategy be made publicly available, and will it be filed with the BCUC?

RESPONSE:

Yes, BC Hydro plans to make materials related to BC Hydro's diesel reduction strategy available to the public and the BCUC upon completion of the strategy. BC Hydro has not yet determined the forum or format in which the document may be made public.

BC Hydro F2020 – F2021 Revenue Requirements

BC HYDRO UNDERTAKING NO. 21

HEARING DATE: January 24, 2020

REQUESTOR: ZONE II RPG, Mr. Wang

TRANSCRIPT REFERENCE: Volume 9, Page 1586, line 13 to Page 1588, line 11

TRANSCRIPT EXCERPT:

MR. WANG: Q I think at this point we're looking for information that would substantiate and give us insight into BC Hydro efforts to explore these, you know, diesel reduction strategies based on examinations of these other jurisdictions that Mr. O'Riley has referenced. So we are looking for that kind of supportive material.

MS. DASCHUK: A So I think there's two aspects to that. One is what have we actually found when we talked to other jurisdictions. The second part is how are we incorporating that into our discussions with each of the communities. What I can say is that each of the communities is different and has a different approach to it. But there are four pillars that underlie the basic approach of the diesel reduction plan, and that is -- if you don't mind me actually reading the materials that I have. Thank you.

MR. WANG: Q Go ahead.

MS. DASCHUK: A Support communities to develop expertise and experience in energy efficiency and clean generation. Retrofit existing homes and buildings to make them highly energy efficient. Develop renewable heating systems including heat pump technology and district energy systems. Implement renewable energy programs to offset all or most of the remaining diesel generation including rooftop solar voltaic and community scale renewable systems.

So those are the four basic pillars. Underneath that, for each one of the communities, there is a set of activities that are taking place. So for example, we would, in some communities be working on a community energy plan. That community energy plan is the equivalent of a mini integrated resource plan for that community.

We would be working with them on a demand-side management plan, and we can speak to that on Panel 5 about the NIA DSM program.

And there are other initiatives that work to build overall capacity within various communities, energy champions within those communities to support the development of an energy capacity within those communities.

MR. WANG: Q Okay thank you for that answer. I'm just going to turn to my friend Mr. Ghikas. Did my last request seem sufficient for now?

MR. GHIKAS: Yeah, I think that's fine. We will take that undertaking, Mr. Chairman, and to the extent that need any clarification we'll get it from just talking offline to my friend.

QUESTION:

Please provide a summary of how BC Hydro's efforts to reduce diesel generation in the Non-Integrated Areas are informed by experiences in other jurisdictions.

RESPONSE:

The following points summarize how BC Hydro's efforts to reduce diesel generation in the Non-Integrated Areas (NIA) are informed by experiences in other Canadian jurisdictions.

- **Many utilities in Canada are active in remote-community electrification;**
- **BC Hydro has ongoing conversations with other utilities regarding their remote community diesel reduction work, and also conducts separate research on the issue;**
- **BC Hydro is an active member of the Off-grid Utilities Association, sharing best practices and lessons learned, including diesel reduction. The members include the off-grid groups of the following utilities:**
  - **BC Hydro, Hydro Quebec, Hydro One Remotes (Ontario), ATCO Electric Yukon, ATOC Electric Alberta, Northwest Territories Power Corporation, Manitoba Hydro, Newfoundland & Labrador Hydro, Qulliq Energy Corporation (Nunavut), Alaska Village Electric Coop, and Cordova Electric Coop (Alaska);**
- **BC Hydro performed a jurisdictional review, for comparative purposes, while designing our NIA DSM Program. We only found one other jurisdiction with a NIA DSM program in place at the time. This did not inform our program design, which is based on the specific needs of our NIA customers;**
- **Based on the information available to BC Hydro, other utilities are encountering similar challenges and issues to BC Hydro regarding diesel reduction initiatives. This provides valuable context for BC Hydro strategic decisions; and**
- **The following types of projects are being observed and discussed for remote community diesel reduction. Note that not all types of projects may be viable in a specific community:**
  - **Biomass heat with district heating;**
  - **Biomass combined heat and power with district heating;**
  - **Hydro (stored and run of river);**
  - **High or low penetration solar;**
  - **High or low penetration wind;**

- **Battery energy storage & Microgrid controls; and**
- **Grid connections.**

The following table provides some of the prominent examples of recent activity in other jurisdictions.

Province	Activity
Hydro Quebec	Quebec conducted an RFP for biomass generation in the off-grid system of Obedjiwan in 2016. BC Hydro's understanding is that this RFP has not yet led to an operational project.
	Hydro Quebec received $11 million in 2019 for a smart-grid project to reduce diesel use in 13 remote Indigenous communities. BC Hydro's understanding is that Hydro Quebec is preparing a diesel reduction plan to accompany this funding.
Ontario	The federal and Ontario provincial governments provided $1.6 billion in funding to create an entity to construct and operate transmission lines to electrify 32 remote communities in Ontario which were historically served by diesel generation. The resulting Wataynikaneyap Power LP is owned 49 per cent by FortisOntario and 51 per cent by a partnership of 24 Indigenous communities. Wataynikaneyap Power LP has completed an initial section of transmission line to connect an initial 16 communities, and has two further phases of construction planned for 2019 to 2023.
	Hydro One Remotes signed an EPA with the community of Gull Bay for supply of solar generated power. The community owns and operates the solar farm, batteries and the microgrid controller. Hydro One owns and operates the diesel system. Ontario Power Gen was the project developer.
Yukon	Four communities (all Indigenous) in the Yukon rely exclusively on diesel generation. Remote communities are eligible to participate in an unsolicited proposal process.
	The Old Crow solar project in the Yukon is a 900 kW solar project with 350 kWh of battery storage. The project is being developed by a consortium of First Nations partnered with an IPP developer (BBA). BC Hydro's understanding is that the initial solar construction is complete, with microgrid controllers and battery systems under construction and will end as utility assets.
	There have been recent discussions between the Taku River Tlingit First Nation (located in the BC Hydro NIA community of Atlin) and Yukon Energy about construction of storage hydro facilities near Atlin with a transmission line to supply the Yukon. BC Hydro is not a participant in these discussions and has limited information on the potential outcome.
	The village of Teslin has implemented a biomass boiler and district heating system which commenced operations in 2017. The project was funded with a combination of grants from the territorial government and Natural Resources Canada.

Province	Activity
Manitoba	**Manitoba Hydro partnered with Aki Energy, an Indigenous non-profit social enterprise group, and provided $19 million in funding to supports DSM and geothermal heat.**
	The community of Lac Brochet has installed a 282 kW solar facility to offset diesel generation, and it considering whether to also add a biomass district heating system.
Northwest Territories	**Northwest Territories Power Corporation (NWTP) led the addition of a solar farm, battery energy storage system and microgrid controller to its existing diesel based system at Colville Lake. NWTP continues to own, operate and maintain the full system. Total system size will be 1.885 MW.**

BC HYDRO UNDERTAKING NO. 22

HEARING DATE: January 24, 2020

REQUESTOR: ZONE II RPG, Mr. Wang

TRANSCRIPT REFERENCE: Volume 9, Page 1608, line 3 to Page 1609, line 1.

TRANSCRIPT EXCERPT:

MR. WANG: Q All right. I'm just going to turn to page 12 of 17 of the witness aid and I just have a request for additional information. That will be my last question. There's a poorly reproduced table at the bottom of page 12 of 17, it's Appendix O, and it is Table 10.1 and it reads, "NIA total gross requirement sales history and forecast after rate impacts and after DSM". Is it possible to have the first three columns broken down into commercial, residential and industrial load as an undertaking?

MR. CLENDINNING: A I actually have Appendix O here so we're just trying to take a look at the table to try and confirm for you today before we go what we've got, so bear with us.

MR. WANG: Q Sure.

MR. RICH: A I'd have to go back and confirm whether we actually have a breakdown by customer classes for each of the NIAs. I think we do. I just have to take it back and confirm with my staff.

MR. WANG: Q All right, then I will leave that as an undertaking, if possible, to break those columns in Appendix O down into commercial, residential, and industrial loads.

QUESTION:

Please breakdown Table 10-1 of Appendix O of the Application by customer class for the first three columns.

RESPONSE:

The table below provides a breakdown of the Non-Integrated Area (NIA) load forecast, before rate impacts and before DSM adjustements, by sector.

Sector Breakdown of NIA Load Forecast Before Rate Impacts and Before DSM[1]

	Purchase Areas[2]	**Zone II and Zone 1B**			**Fort Nelson**		
(GWh)	**Breakdown Not Available**[3]	Residential	Commercial & Light Industrial	Large Industrial	Residential	Commercial & Light Industrial	Large Industrial
F2019	14	60	44	0	21	40	119
F2020	15	61	47	0	21	40	120
F2021	15	62	47	0	21	41	120
F2022	15	62	48	0	21	75	120
F2023	15	62	48	0	21	76	120
F2024	15	62	48	0	21	77	120

Notes:

1. The above table shows values before DSM and rates adjustments. These adjustments are applied at the total level not the sector level so a breakdown after adjustments is not available. Table 10-1 of Appendix O of the Application is after adjustments for DSM and rates and also includes other loads such as street light customers, irrigaiton customers, BC Hydro own use, and losses.
2. The Purchase Areas consists of the following locations in the South Interior: Lardeau, Shutty Bench Crowsnest, Newgate, Kinsgate-Yahk, and Kelly Lake.
3. The Purchase Area forecast is developed by trend analysis of the historical total gross requirements of the communities and therefore a breakdown by sector is not available.

BC HYDRO UNDERTAKING NO. 23

HEARING DATE: January 23, 2020

REQUESTOR: BCUC, Ms. E. Gjoshe

TRANSCRIPT REFERENCE: Volume 8A: (Page 1107, line 11 to Page 1108, line 26 and Page 1110, line 19 to Page 1112, line 24 and Page 1232, line 13 to Page 1235, line 21)

TRANSCRIPT EXCERPT:

MS. GJOSHE: Q I appreciate that, thank you, yes. So, to follow with Exhibit B-1, page 1-9, line 12, I will quote, I will read from that.

"The following provides a summary of the actions that the Government of B.C. and BC Hydro are taking to keep rates affordable. Further on line 15 it describes the first measure as writing off 1.1 billion deferral account balance. The write-off of the rate smoothing regulator account contributes to a reduction in BC Hydro's forecast overall regulatory account balance at the end of Fiscal 2019 by 24 percent, from 4.7 billion to 3.6 billion. Lowering the overall regulator account balance means lowering the amount that would otherwiswe be recovered from ratepayers, redeucing pressure on rates."

Is it fair to say that this is largely a government action?

MR. LAYTON: A It is fair, that came out of the comprehensive review phase 1. Obviously we contributed as part of that review, but that was ultimately a government decision and the impact of that decision was therefore felt by the shareholder as government and in essence that write-off, what it meant was, that's $1.1 billion that we will not recover from customers in the future. Instead, that's borne by the shareholder, first in the form of lower net income last year. We actually had a net loss last year as a result of that write-off and what that means is that that contributes to government's overall budget, surplus or deficit, as opposed to being recovered from ratepayers in the future.

MS. GJOSHE: Q Thank you for that, Mr. Layton. Notwithstanding the merits of it, is it fair to say that it contributes to BC Hydro achieving top quartile rankings in the benchmarking efforts study?

MR. LAYTON: A Yes, I think that and many other factors that contribute to overall budgets and rates, but absolutely it's fair to say that having lower rates that was enabled in part by this write-off absolutely contributes to our place in the survey, yes.

...

MS. GJOSHE: Q And I'm not a partisan of that, but to the degree that, say, if as a result of the inclusion of that 1.1 billion write-off you – let's say hypotheticaly BC Hydro would no longer be in the top quartile, would that impact your performance review and, therefore, your – and there was lots of discussion yesterday about holdback, and bonuses, and this and that, would that impact the performance review and how BC Hydro views its own efforts?

MS. FRASER A I think some information just before perhaps Mr. Wong answers that question, is that in prior years we have been the first quartile and those prior years included the rate smoothing without the write-offs. So we have been consistently over a number of years been in the first quartile with or without the rate smoothing write-off.

MS. GJOSHE Q Thank you for that. I will leave it at that, I just wanted to –

THE CHAIRPERSON: May I? Ms. Fraser, the rate smoothing, historically, the way that's been working is that that's been keeping rates lower, whereas I think what Ms. Gjoshe's talking about is the review being a scenario where you would be amortizing the rate smoothing account, am I correct there?

MS. FRASER: A Right.

THE CHAIRPERSON: That may not be a correct assumption, but --

MR. LAYTON: A I think that's fair, yes.

THE CHAIRPERSON: Yeah. So the result might well be different in a scenario where you're amortizing it in a scenario where you're, you know, building it up and keeping rates down.

MS. FRASER: A Right.

THE CHAIRPERSON: I Just wanted to point that out.

MR. LAYTON: A If the rate smoothing regulatory account had not been written off, then we would be recovering it between now and Fiscal '24 and that would result in higher rates then otherwise would be the case.

THE CHAIRPERSON: Exactly. Exactly, yeah.

MR. LAYTON: A And in those future years it would result – all else equal and higher bills than would otherwise be the case, that I think would be reflected in our ranking in future studies as that amount is recovered in rates.

THE CHAIRPERSON: Right. So the calculation that's being asked for would be to take the amortized amount over four years and simply add that to the rates. That doesn't – I mean whether you do it or not, that's up to you and Ms. Gjoshe, but it just doesn't sound that complicated to me.

MR. LAYTON: A Yeah. And if it's – as I mentioned, if it's simply taking that and making a base assumption on when we would recover it, we can do that. I think if the request is just to add that to the forecast we would have in the evidentiary update and show what would rates be, I think that is indeed relatively straight forward. Yes.

...

THE CHAIRPERSON: I understand, thank you. A couple of questions for Ms. Fraser. I don't have the transcript reference here but I believe that yesterday you mentioned in a longer list of things that one of the items that pay incentives are tied to or are associated with are rates. Did I hear that correctly? Keeping rates low, I think, is what you may have said.

MS. FRASER: A Yes. And it was, I believe, mentioned this morning too. So our service plan scorecard contains a metric of achieving first quartile for residential according to the Hydro Quebec report and so the service plan contains a number of metrics, that's one of them, and how we achieve all those metrics is used for holdbacks for the corporate portion of the holdback.

THE CHAIRPERSON: But basically the metric is whether you match or come in below Hydro Quebec's rate?

MS. FRASER: A It's whether you're in first quartile or not, yeah.

THE CHAIRPERSON: Right. So if government comes along with a direction to us to set rates at a certain amount or not increase rates so that that aligns it with -- and then orders a rate smoothing account, do your employees still get the benefit of that incentive?

MS. FRASER: A They would. They would still get the benefit. And remember, the holdbacks, I believe Ms. Ryan said, it's 1 percent of the employee population that get those holdbacks.

MS. RYAN: A That's correct.

THE CHAIRPERSON: Understood. But your executive team, for example, gets –

MS. FRASER: A Yes.

THE CHAIRPERSON: So that could be described as a bit of a windfall from a government decision then, one could describe it that way, couldn't one?

MS. FRASER: A If they're setting rates to ensure that -- or if they're making directions to ensure that our rates are actually in the first quartile, then that's beneficial from a perspective of the amount of holdback.

THE CHAIRPERSON: Right, but you don't have to manage costs to those rates though. During the rate smoothing period or during the ten-year rates plan rates were set but you didn't have to manage cost of those rates because there was a rate smoothing deferral account in which costs went. So you're still getting the benefit of the incentive, presumably, assuming that those rates put you in that quartile. You would still get the benefit of the incentive without having to do the managing costs part of it?

MS. FRASER: A Yeah, so during the rates plan period we were managing costs to the rates plan.

THE CHAIRPERSON: Okay, and that's what the incentive was based on then?

MS. FRASER: A No, the incentive was still based, you know, on the one -- on that metric. But internally we had to, for government, meet the rates plan.

THE CHAIRPERSON: Understood.

MS. FRASER: A And, you know, there were times during the -- especially when we saw some closures early on in the forest industry, that we really had to make some tough decisions internally to stay on the rate plan, because that was our commitment to our shareholder, was to stay on that rates plan, and so we were definitely managing, you know, costs internally to keep them as low as possible.

THE CHAIRPERSON: But is it fair to say though that -- let's say -- to simplify this let's say there's two components to the ten-year rates plan. One is the costs the government asked you to manage to, and the second are the rates that government ordered us to impose or to approve.

So if they had only done the former and not the latter, then -- and there had been no deferral account, then rates may have been higher and you may not have been in that quartile and you would then not have gotten –

MS. FRASER: A Correct.

THE CHAIRPERSON: Okay.

MS. FRASER: A Correct.

THE CHAIRPERSON: You would agree with that?

MS. FRASER: A Correct.

THE CHAIRPERSON: Thank you.

MS. FRASER: A Depending on what was happening with the other utilities in that survey.

QUESTION:

To what extent did the deferral of portions of BC Hydro’s approved revenue requirement into the Rate Smoothing Regulatory Account and the Government of B.C.’s subsequent decision to write-off the balance in the Rate Smoothing Regulatory Account affect BC Hydro’s ranking in the Comparison of Electricity Prices survey completed by Hydro Quebec and by extension its Service Plan results and the corresponding corporate component of holdback awards to BC Hydro’s Executive and Director-level employees?

RESPONSE:

For context, BC Hydro provides the following two points:

- **First, as discussed further in BC Hydro's responses to BCUC IRs 1.42.10 and 1.42.10.1, only 1 per cent of BC Hydro's employees are eligible to receive holdback pay. A portion of an employee's holdback pay is attributable to individual performance, which is not impacted by corporate results and the corporate component of an employee's holdback pay is determined by the multiple performance measures in BC Hydro's Service Plan; and**
- **Second, while the decision to write-off the balance in the Rate Smoothing Regulatory Account was made by the Government of B.C., it was an outcome of Phase One of the Comprehensive Review, which was a collaborative effort between BC Hydro and government. It reflected the contributions of BC Hydro employees to that process as well as broader efforts, by BC Hydro, over a number of years, to identify and evaluate opportunities to take pressure off rates.**

It is not possible to determine how the Government of B.C.'s decision to write-off the balance in the Rate Smoothing Regulatory Account will affect BC Hydro's ranking in the Hydro Quebec survey going forward. An analysis of this nature would require confirmed information about future rate increases for other utilities that are included in the survey.

However, BC Hydro was able to conduct a retrospective analysis to determine if BC Hydro's ranking in the Hydro Quebec survey and the resulting score used to determine the corporate component of holdback awards, would have been different if BC Hydro had not had the ability to defer portions of its approved revenue requirement into the Rate Smoothing Regulatory Account from fiscal 2015 to fiscal 2019. The results of this analysis are as follows:

- **In all years, except fiscal 2015, there would have been no impact to BC Hydro's Competitive Rates performance measure;**
- **In fiscal 2015, the Competitive Rates performance measure in BC Hydro's Service Plan would have been impacted. BC Hydro would have been in the first quartile in two of the three of the rate classes that were included in the measure at the time instead of being in the first quartile in all three of the rate classes; and**
- **Had this result been used to calculate holdback pay awards in fiscal 2015, the score used to determine the corporate component would have been 0.78 instead of 0.79. If this lower score had been used, BC Hydro estimates that the total holdback award expenditure in that year would have been approximately $7,000 less in total or approximately $100 to $200 per employee that received a holdback award.**