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January 17, 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 its responses to Round 2 Panel information requests as follows:

Exhibit B-31	Responses to Panel IRs (Public Version)
Exhibit B-31-1	Responses to Panel IRs (Confidential Version)

BC Hydro is filing some IR responses and/or attachments to responses confidentially with the Commission. BC Hydro confirms that in each instance, an explanation for the request for confidential treatment is provided in the public version of the IR response. BC Hydro seeks this confidential treatment pursuant to section 42 of the *Administrative Tribunals Act* and Part 4 of the Commission's Rules of Practice and Procedure.

For further information, please contact Chris Sandve at 604-974-4641 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

(for) Fred James
Chief Regulatory Officer

cs/rh

Enclosure

3.0 A. CHAPTER 4 – COST OF ENERGY

Reference: COST OF ENERGY
Exhibit B-1, Application, p. 2-9; Exhibit B-16, BCUC IR 304.5
Cost of IPP Energy – Exempt vs. Non-Exempt

Page 2-9 of the Application states:

> Section 4 of Direction No. 8 provides direction in this area to recover costs related to previous policy decisions by the Government of BC. It states that the BCUC must not disallow recovery in rates of the balance of BC Hydro's regulatory accounts as at March 31, 2019. It also states that the BCUC must also not disallow costs incurred by BC Hydro with respect to…energy supply contracts entered into before fiscal 2017…

British Columbia Hydro and Power Authority's (BC Hydro) response to British Columbia Utilities Commission (BCUC) Information Request (IR) 304.5 provides the below table that reflects forecast energy supply contracts entered into by BC Hydro from April 1, 2016 to June 1, 2019:

	F2020 EU	F2021 EU
GWh	346	434
Total Cost ($ millions)	19.4	27.4

2.3.1 Please complete the below table showing the total forecast annual volume and cost for all energy supply contracts entered into by BC Hydro before April 1, 2016, that identifies all Electricity Purchase Agreements (EPAs) with Independent Power Producers (IPPs) contracts that were reviewed by the BCUC, and those EPAs that were exempt from BC Hydro review.

F2020	Exempt	Non-Exempt	Total
GWh			
Cost ($ million)			
Total			
F2021	**Exempt**	**Non-Exempt**	**Total**
GWh			
Cost ($ million)			
Total			

RESPONSE:

The table below provides the requested information in relation to Fiscal 2020 and Fiscal 2021 for energy supply contracts entered into before April 1, 2016.

BC Hydro notes the following with respect to the information presented in the table below and our response to BCUC IR 3.304.5:

- **The analysis is based upon the June 2019 forecast used for the Evidentiary Update, Exhibit B-11 in this proceeding;**
- **Energy supply contracts originally reviewed by the BCUC but which were subsequently included within an exemption are included as "Non-Exempt" agreements. For example, 2008 Standing Offer Program energy supply contracts were reviewed and accepted by the BCUC, but subsequently the *Clean Energy Act* exempted Standing Offer Program contracts from section 71 of the *Utilities Commission Act*;**
- **Energy supply contracts originally exempt from a section 71 filing under the *Utilities Commission Act*, and where subsequently their extension agreements were filed pursuant to section 71 and reviewed by the BCUC, are included as "Non-Exempt" if the extension agreement came into effect prior to fiscal 2020. For example, the Ocean Falls electricity purchase agreement, which was originally exempt, is included as "Non-Exempt" since the extension agreements were filed and reviewed by the BCUC;**
- **The existing original energy supply contract for Walden North is included in the table below as "Exempt". The new energy supply contract for Walden North entered into after April 1, 2016, which has not been accepted by the BCUC and is still being considered by the BCUC in a separate proceeding, is also reflected in BC Hydro's response to BCUC IR 3.304.5. However, for the cost of energy as shown in Schedule 4 of the Application, the Walden North forecast GWh and costs are only accounted for once as the values for these two agreements is the same for fiscal 2020 and fiscal 2021; and**
- **The information included in BC Hydro's response to BCUC IR 3.304.5 reflects the forecast for energy supply contracts entered into by BC Hydro from April 1, 2016 to June 1, 2019, but does not include the forecast of those energy supply contracts that did not have executed agreements as of June 1, 2019 or any costs following the expiry date of those contracts that are due to expire during the test period.**

F2020	Exempt	Non-Exempt	Total
GWh	8,312	4,837	13,148
Cost ($ million)	776	413	1,189
F2021	**Exempt**	**Non-Exempt**	**Total**
GWh	7,839	5,908	13,747
Cost ($ million)	807	467	1,274
Total F2020 & F2021	**Exempt**	**Non-Exempt**	**Total**
GWh	16,150	10,745	26,895
Cost ($ million)	1,583	880	2,463

British Columbia Utilities Commission Panel Information Request No. **2.4.1** Dated: **December 12, 2019** British Columbia Hydro & Power Authority Response issued **January 17, 2020**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-31**

4.0 A. CHAPTER 4 – COST OF ENERGY

Reference: COST OF ENERGY
Exhibit B-1, Appendix DD, pp. 1, 8
Energy Studies Process Audit

Page 1 of Appendix DD identifies the following individuals who prepared the Q3 Fiscal 2019 (F2019) Energy Studies Process Audit (Audit):

Prepared By:

B. Mo (SINTEF)
A. Helseth (SINTEF)
J. Chong
R. Prinja
A. Lagnado

Page 8 describes both B. Mo and A. Helseth as research scientists employed by SINTEF.

Page 8 also states that B. Mo has “participated in previous BC Hydro reviews and consulting work related to the Peace model (1998) and Columbia modelling and coordination (1999 and 2008).”

2.4.1 Please confirm whether the individuals not identified as SINTEF employees are employees of BC Hydro. If not, please identify where they are employed and their expertise as it relates to the energy studies and / or audit process.

RESPONSE:

Confirmed, the individuals are members of BC Hydro Audit Services.

4.0 A. CHAPTER 4 – COST OF ENERGY

Reference: COST OF ENERGY
Exhibit B-1, Appendix DD, pp. 1, 8
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Page 8 also states that B. Mo has "participated in previous BC Hydro reviews and consulting work related to the Peace model (1998) and Columbia modelling and coordination (1999 and 2008)."

2.4.2 Please discuss the process used in awarding consulting work to SINTEF. Was this done through an RFP process? If not, why not?

RESPONSE:

Given the specialized technical expertise required, a formal request for proposal (RFP) process was not used. Public competition was not required because the estimated cost of the work was below competitive thresholds.

At times, Audit Services undertakes audit engagements in complex areas which require supplemental resources such as external firms or individuals with very specialized expertise. Given the expertise required, there is often a limited pool of candidates.

For this audit, Audit Services identified and contacted a number of potential international consultants. The purpose was to find individual(s) who specialized in large storage hydro-electric operations, who were available during the specified audit timeframe, and possessed technical knowledge in energy economics for operations, and hydropower scheduling and optimization.

Audit Services contacted four consultants to outline the engagement requirements and expectations as well as to request resumes. Audit Services

received three responses and then followed up to further discuss professional qualifications, relevant work experience, and availability.

After these discussions, SINTEF was identified by Audit Services as the most suitable candidate. Once Audit Services and SINTEF reached an agreement on compensation, a contract was subsequently finalized and approved in accordance with procurement processes.

5.0 A. CHAPTER 4 – COST OF ENERGY

Reference: COST OF ENERGY
Exhibit B-1, p. 1-15; Appendix DD, pp. 8, 9; Exhibit B-5; BCUC IR 15.3, 28.1, 29.1.1; Exhibit B-16, BCUC IR 309.1; BC Hydro Application for 2019 Letter Agreement with Powerex Corp. (2019 Powerex Letter Agreement Application), Exhibit B-5, BCOAPO IR 2.1; Exhibit B-7, BCUC IR 1.1; Exhibit B-8, BCUC IR 2.1.2
Energy Studies – Risk and Operations

On page 1-15 of the Application, BC Hydro states: “Our monthly Energy Studies optimize our operational management of all sources of energy supply on BC Hydro’s integrated system”.

On page 8 of Appendix DD to the Application, one of two objectives of the Energy Studies Process Audit is stated as “To evaluate whether the monthly Energy Studies process reliably supports operations, financial and strategic planning at BC Hydro.”

On page 9 of Appendix DD, a key finding of the Energy Process Audit is that “Energy Study reports are prepared on time and contain an appropriate level of detail; however they do not serve short-term operational planning needs.”

2.5.1 Please explain why the Energy Study reports do not serve short term operational planning needs. How does BC Hydro plan to address this key finding?

RESPONSE:

BC Hydro’s complete suite of operational tools do serve our needs for short term operational planning. BC Hydro has other tools that are used for within month planning. It is important to note that Energy Study Process Audit did not look at all of BC Hydro’s operational tools and made no determination of their suitability for meeting short term operational needs. The key finding and recommendation has to be understood within that context.

The audit noted that one of these short term models, the Ultralight model, can be executed within one day to provide updated water values, but is not as sophisticated as the Energy Study Models (which take three weeks to run) and relies on the Energy Studies results as a starting point. There will always be a trade-off between speed of calculations and sophistication. The recommendation in the audit was for BC Hydro management to consider replacing the Ultralight model with a more robust model that is formally coupled with the Energy Studies

models. BC Hydro is interested in exploring this idea further; however, it is a lower priority than other model improvements and tasks that the Generation System Operations team is currently working on.

The Energy Studies do not serve short-term operational planning needs because they are not designed for within month operations and are executed on a monthly schedule. The studies are not intended to accommodate within month changes, nor is it necessary for them to do so, since the primary operational outputs of the studies - basin prices - represent the long-term value of energy in our reservoirs and are generally not sensitive to short-term volatility in inputs.

BC Hydro has other tools that do serve the within month operational planning needs that are used to manage individual plants and the system as a whole to be responsive to rapidly changing conditions within the month (e.g., storms, cold snaps, forced outages). These models are typically deterministic and use the longer term Energy Studies results as a starting point.

For example, across the winter of fiscal 2019, the probabilistic forecast of BC Hydro's short position was being updated weekly to inform import requirements. The basis of this forecast was the monthly Energy Study, but short term updates based on critical inputs were completed weekly. In addition, in February during the four to six-week cold snap, the weather impact on load was being updated every few days.

5.0 A. CHAPTER 4 – COST OF ENERGY

Reference: COST OF ENERGY
Exhibit B-1, p. 1-15; Appendix DD, pp. 8, 9; Exhibit B-5; BCUC IR 15.3, 28.1, 29.1.1; Exhibit B-16, BCUC IR 309.1; BC Hydro Application for 2019 Letter Agreement with Powerex Corp. (2019 Powerex Letter Agreement Application), Exhibit B-5, BCOAPO IR 2.1; Exhibit B-7, BCUC IR 1.1; Exhibit B-8, BCUC IR 2.1.2
Energy Studies – Risk and Operations

BC Hydro's response to BCUC IR 15.3 states:

> The Energy Studies model operations for the next five years (i.e., to the end of fiscal 2024 in the current studies). These results are used for operational decision making (e.g. setting the threshold sale price) and for near-term financial forecasts (e.g., the Cost of Energy forecast in the Application). However, operational forecasts are not used to determine the need for new resources.

BC Hydro's response to BCUC IR 28.1 states "In the month-to-year ahead time horizon, the Energy Study provides an appropriate level of guidance in terms of pricing, given that large storage reservoirs fill and draft on a seasonal time scale."

2.5.2 Please confirm, or otherwise explain, that "setting the threshold sale price" refers to the price used to determine how exports in the Transfer Pricing Agreement are allocated between BC Hydro and Powerex Corp. (Powerex).

RESPONSE:

Confirmed.

5.0 A. CHAPTER 4 – COST OF ENERGY

Reference: COST OF ENERGY
Exhibit B-1, p. 1-15; Appendix DD, pp. 8, 9; Exhibit B-5; BCUC IR 15.3, 28.1, 29.1.1; Exhibit B-16, BCUC IR 309.1; BC Hydro Application for 2019 Letter Agreement with Powerex Corp. (2019 Powerex Letter Agreement Application), Exhibit B-5, BCOAPO IR 2.1; Exhibit B-7, BCUC IR 1.1; Exhibit B-8, BCUC IR 2.1.2
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BC Hydro's response to BCUC IR 28.1 states "In the month-to-year ahead time horizon, the Energy Study provides an appropriate level of guidance in terms of pricing, given that large storage reservoirs fill and draft on a seasonal time scale."

2.5.2 Please confirm, or otherwise explain, that "setting the threshold sale price" refers to the price used to determine how exports in the Transfer Pricing Agreement are allocated between BC Hydro and Powerex Corp. (Powerex).

2.5.2.1 Please explain why monthly Energy Studies use a five-year time horizon when an appropriate level of guidance in terms of pricing is provided for a time horizon up to a year only. In your response, please confirm whether pricing guidance provided by the Energy Study for the month-to-year time horizon resets every month, and whether threshold sale prices established in subsequent monthly Energy Studies are compared against threshold sale prices established in prior months as a way of validating monthly Energy Studies.

RESPONSE:

Optimization over Five Years

The first year of the modelling timeframe is the most important for current operational decisions. In the Energy Studies optimization, the forecast of drivers (inflows, load, market prices, etc.) and system conditions that are closer in time to the present will generally have a larger impact on the near-term results than those same factors further out in time.

The system storage is, however, multi-year storage and significant operational constraints or larger changes in load or market price that are forecast to occur in future years can affect operation in the current year. Hence, the energy study optimization has to consider a long time horizon.

In the Energy Studies, the storage at the end of the modelled time horizon is assigned a value. This boundary condition emulates the value of using the storage beyond the five-year time horizon, and is required otherwise the model would empty the reservoirs by the end of the modelled period due to the objective of maximizing consolidated net revenue within the modeled period. Modelling an additional two years ensures that this boundary condition does not impact the operating three-year period and allows the forecast for the first three years to account for the impact of any longer term operational constraints (e.g., significant outages scheduled in the fourth and fifth year).

Note that the fact that the Energy Studies optimize the reservoir operations over five fiscal years into the future and the operating time horizon is three years is not inconsistent. The three-year operating time horizon is the time horizon within which the Generation System Operations business group has accountability to plan the use of generation resources that are available to BC Hydro to ensure that load serving obligations are met.

Use of Energy Studies Information

The information from an Energy Study is used for operations until it is updated in the next monthly Energy Study. Operational forecasts are updated within the month as needed using other tools.

For example, across the winter of fiscal 2019, the probabilistic forecast of BC Hydro's short position was being updated weekly to inform import requirements. The basis of this forecast was the monthly Energy Study, but short term updates based on critical inputs were completed weekly. In addition, in

February during the four to six-week cold snap, the weather impact on load was being updated every few days.

It is important to note that the Energy Studies and other models are decision support tools that inform decisions by management. The threshold sale price or threshold purchase price are at times adjusted within the month between Energy Studies if changing conditions warrant a change in the threshold price. These within month changes are based on other tools or preliminary Energy Studies results, and are then compared to the final Energy Studies results and adjusted again as needed.

The threshold prices are an output from the Energy Studies model and are not compared against prior months as a way of validating the Energy Studies. Instead the probabilistic variable inputs of inflow, load, and market prices are tracked and used to decide if they have changed significantly to warrant a change in threshold price. Likewise, forecasts of system reservoir levels, generation, import/exports are tracked to see if they are varying from the Energy Study. If there is a variance from the Energy Studies, then analysis of the drivers is performed to determine why the change occurred and inform any decisions.

5.0 A. CHAPTER 4 – COST OF ENERGY

Reference: COST OF ENERGY
Exhibit B-1, p. 1-15; Appendix DD, pp. 8, 9; Exhibit B-5;
BCUC IR 15.3, 28.1, 29.1.1; Exhibit B-16, BCUC IR 309.1;
BC Hydro Application for 2019 Letter Agreement with Powerex Corp. (2019 Powerex Letter Agreement Application), Exhibit B-5, BCOAPO IR 2.1; Exhibit B-7, BCUC IR 1.1; Exhibit B-8, BCUC IR 2.1.2
Energy Studies – Risk and Operations

BC Hydro's response to BCUC IR 1.1 in the 2019 Powerex Letter Agreement Application states "Energy Studies are done monthly and look out five years for the reasons set out in BC Hydro's response to BCOAPO IR 1.2.1. BC Hydro confirms that the operating time horizon is not a rolling period up to three years."

BC Hydro's response to British Columbia Old Age Pensioners' Organization et al. (BCOAPO) 2.1 in the 2019 Powerex Letter Agreement Application states:

> The Energy Studies model the dispatch of the system five fiscal years into the future; running the model for the additional two years allows the forecast for the first three years to account for the impact of longer-term operational constraints (e.g., scheduled outages in the fourth and fifth years).

BC Hydro's response to BCUC IR 2.1.2 in the 2019 Powerex Letter Agreement Application provides the below table, that identifies the difference between the operating time horizon and the planning horizon:

Year	F20	F21	F22	F23	F24	[...]	F40+
Operating time horizon							
Planning time horizon							

2.5.3 Please confirm the date when the most recent three-year operating time horizon was set, given it is not a rolling period up to three years. As part of your response, please confirm when the next operating time horizon will be set.

RESPONSE:

The operating time horizon is defined as the balance of the current fiscal year and the following two fiscal years (and so does not ever exceed three years). As a

result, the most recent three-year period was set on April 1, 2019 for the period April 1, 2019 through March 31, 2022.

The next operating time horizon will be set on April 1, 2020 for the period April 1, 2020 through March 31, 2023.

5.0 A. CHAPTER 4 – COST OF ENERGY

Reference: COST OF ENERGY
Exhibit B-1, p. 1-15; Appendix DD, pp. 8, 9; Exhibit B-5; BCUC IR 15.3, 28.1, 29.1.1; Exhibit B-16, BCUC IR 309.1; BC Hydro Application for 2019 Letter Agreement with Powerex Corp. (2019 Powerex Letter Agreement Application), Exhibit B-5, BCOAPO IR 2.1; Exhibit B-7, BCUC IR 1.1; Exhibit B-8, BCUC IR 2.1.2
Energy Studies – Risk and Operations

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BC Hydro’s response to BCUC IR 2.1.2 in the 2019 Powerex Letter Agreement Application provides the below table, that identifies the difference between the operating time horizon and the planning horizon:

Year	F20	F21	F22	F23	F24	[...]	F40+
Operating time horizon							
Planning time horizon							

2.5.4 Please confirm whether the planning horizon that follows the operating time horizon is a rolling period. As part of your response, please confirm when the next planning time horizon will be set.

RESPONSE:

The planning time horizon starts at the end of the operating time horizon, and therefore rolls forward by one year at the same time as the operating time horizon at the beginning of each fiscal year. The current planning horizon starts on

April 1, 2022. On April 1, 2020 the planning time horizon will change to start on April 1, 2023.

BC Hydro notes that planning decisions consider the longer term horizon and these decisions are often made during the operating time horizon.

5.0 A. CHAPTER 4 – COST OF ENERGY

Reference: COST OF ENERGY
Exhibit B-1, p. 1-15; Appendix DD, pp. 8, 9; Exhibit B-5;
BCUC IR 15.3, 28.1, 29.1.1; Exhibit B-16, BCUC IR 309.1;
BC Hydro Application for 2019 Letter Agreement with Powerex Corp. (2019 Powerex Letter Agreement Application), Exhibit B-5, BCOAPO IR 2.1; Exhibit B-7, BCUC IR 1.1; Exhibit B-8, BCUC IR 2.1.2
Energy Studies – Risk and Operations

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> The Energy Studies model the dispatch of the system five fiscal years into the future; running the model for the additional two years allows the forecast for the first three years to account for the impact of longer-term operational constraints (e.g., scheduled outages in the fourth and fifth years).

BC Hydro's response to BCUC IR 2.1.2 in the 2019 Powerex Letter Agreement Application provides the below table, that identifies the difference between the operating time horizon and the planning horizon:

Year	F20	F21	F22	F23	F24	[...]	F40+
Operating time horizon							
Planning time horizon							

2.5.5 Please explain whether the statement that the Energy Study does not serve short-term operational planning needs relates to the planning time horizon.

RESPONSE:

The statement in the Energy Studies Process Audit that the Energy Study does not serve short-term operational planning needs is referring to the fact the Energy Study is not updated within the month as conditions change. Therefore

"short-term", as used in this context, is a time period less than a month. The statement has no relevance to the planning time horizon.

Please refer to BC Hydro's response to BCUC Panel IR 2.5.1 for a further explanation of meaning of the comment in the Energy Studies Process Audit.

5.0 A. CHAPTER 4 – COST OF ENERGY

Reference: COST OF ENERGY
Exhibit B-1, p. 1-15; Appendix DD, pp. 8, 9; Exhibit B-5; BCUC IR 15.3, 28.1, 29.1.1; Exhibit B-16, BCUC IR 309.1; BC Hydro Application for 2019 Letter Agreement with Powerex Corp. (2019 Powerex Letter Agreement Application), Exhibit B-5, BCOAPO IR 2.1; Exhibit B-7, BCUC IR 1.1; Exhibit B-8, BCUC IR 2.1.2
Energy Studies – Risk and Operations

BC Hydro’s response to BCUC IR 29.1.1 states:

> A risk-neutral operating strategy is based on achieving the expected outcome, assuming each of the modeled possible outcomes is equally likely, and does not bias towards or against favourable or unfavourable outcomes. Long-term refers to the five-year time horizon over which the optimization is run.

2.5.6 Please explain how the maximum actual “risk-neutral long-term net revenue” earned is determined when measured against the relevant Energy Study, if Energy Studies are run monthly and the operating time horizon is fixed for a three-year period. In your response, please explain whether the results of this analysis inform the models used in the monthly Energy Studies.

RESPONSE:

BC Hydro interprets this question to be asking whether the actual historic consolidated net revenue from operations[1] is used as a back-testing metric for verification.

The answer is no, consolidated net revenue is not used for back-testing, as it would not help inform the reliability of the models or operational decisions. The reason is that there are at least two impediments to calculating the “actual” consolidated net revenue that prevent a useful comparison to the forecast for verification purposes:

- **The primary drivers of the consolidated net revenue are inflows, load and market prices. No comparison of monthly forecast and actual values of**

1 Please refer to BC Hydro’s response to BCUC IR 1.29.2 for a description of how consolidated net revenue from operations is calculated.

consolidated net revenue can be usefully obtained without controlling for variances in these inputs; and

- **The forecast of consolidated net revenue is based on an estimate of net income from market purchases and sales that will be subsequently allocated between BC Hydro and Powerex. Splitting out the fraction of Powerex's actual net trade revenue specifically related to system-backed activities as modeled in the Energy Study would be problematic.**

Please refer to BC Hydro's response to BCUC Panel IR 2.7.2 for more information on how the Energy Studies models are verified.

6.0 A. CHAPTER 4 – COST OF ENERGY

Reference: COST OF ENERGY
Exhibit B-1, p. 4-17; Appendix DD, p. 9; Exhibit B-16, BCUC IR 309.1
Energy Study objectives

Page 4-17 of the Application states "The Energy Study optimizes the use of System Storage with imports and exports to meet load requirements."

Page 9 of Appendix DD to the Application states "BC Hydro has developed in-house models for long-term hydrothermal scheduling. These models are built to maximize risk neutral long-term net revenue."

2.6.1 Please define the phrase "long-term hydrothermal scheduling."

RESPONSE:

"Long-term hydrothermal scheduling" is a generic term used by SINTEF[1], the audit consultant, to refer to planning the operation (i.e., scheduling generation) of a hydroelectric system that includes some dispatchable thermal resources. In this case 'long-term' refers to a timeframe of one month to several years.

[1] *SINTEF: Stiftelsen for industriell og teknisk forskning*

6.0 A. CHAPTER 4 – COST OF ENERGY

Reference: COST OF ENERGY
Exhibit B-1, p. 4-17; Appendix DD, p. 9; Exhibit B-16, BCUC IR 309.1
Energy Study objectives

Page 4-17 of the Application states “The Energy Study optimizes the use of System Storage with imports and exports to meet load requirements.”

Page 9 of Appendix DD to the Application states “BC Hydro has developed in-house models for long-term hydrothermal scheduling. These models are built to maximize risk neutral long-term net revenue.”

2.6.2 Please reconcile the objective of the Energy Study to optimize System Storage with imports and exports to meet load requirements, with the other objective that “these models are built to maximize risk neutral long-term net revenue.”

RESPONSE:

BC Hydro’s stated objective on page 4-16 of the Application is to ‘Maximize Consolidated Net Revenue from operations’. “Consolidated” refers to the combined import and export activity to and from the BC Hydro system for both BC Hydro and Powerex. Therefore the sentence on page 4-17 of the Application referred to in the question is consistent with this objective.

BC Hydro’s objective to maximize consolidated net revenue from operations is done on a risk-neutral basis and is therefore the same as the objective to maximize risk neutral long-term net revenue, as referenced in Appendix DD to the Application, as described in BC Hydro’s response to BCUC IR 1.29.1.

6.0 A. CHAPTER 4 – COST OF ENERGY

Reference: COST OF ENERGY
Exhibit B-1, p. 4-17; Appendix DD, p. 9; Exhibit B-16, BCUC IR 309.1
Energy Study objectives

BC Hydro's response to BCUC IR 309.1 states:

> There is no risk allocated to the shareholder. Through the Cost of Energy Variance accounts, the costs and benefits from the consolidated net revenue from operations are allocated to ratepayers.
>
> BC Hydro manages trade-offs in short-term and long-term risks by modelling the system over a five-year time horizon, which takes into account the longer term impacts of any shorter term benefits or costs.

2.6.3 Please expand on the statements that "there is no risk allocated to the shareholder" and that "BC Hydro manages trade-offs in short-term and long-term risks by modelling the system over a five-year time horizon" from the perspective of the ratepayer. In your response, please identify examples of trade offs to demonstrate: i) increases to short-term risks (and therefore decreases to long-term risks) faced by ratepayers: and ii) decreases to short-term risks (and therefore increases to long-term risks) faced by ratepayers as a result of maximizing risk-neutral long-term net revenue.

RESPONSE:

1) Expand on the statement: "There is no risk allocated to the shareholder"

The question in BCUC IR 3.309.1 asks whether the level of risk undertaken by BC Hydro increases as a function of maximizing expected consolidated net revenue, and further, how this risk is allocated.

The response states that "There is no risk allocated to the shareholder. Through the Cost of Energy Variance accounts, the costs and benefits from the consolidated net revenue from operations are allocated to ratepayers."

In responding to this question, it is important to have a clear definition of the term "risk", since "risk" was not defined in either the question or BC Hydro's response. This response is based on the assumption that the risk being referred to is the

probability that there is a material variance between the planned and actual Cost of Energy, since the question was posed in that context.

The Government of B.C., as the recipient of water rental payments (not, in this case in its role as BC Hydro's shareholder) does bear risk in respect of variances between planned and actual water rental payments received being higher or lower than plan. However, the optimization of the generation from inflows primarily impacts the timing of generation, not the total amount, and therefore the water rental payments to the Government of B.C. are not significantly affected by the optimization.

2) Expand on the statement: "BC Hydro manages trade-offs in short-term and long-term risks by modelling the system over a five-year time horizon, which takes into account the longer term impacts of any shorter term benefits or costs"

In this context the risk being referred to is the uncertainty in financial impact of sales or purchases in the short term, and sales or purchases (or reservoir management) in the long term. Short term in this context is the period within which current decisions are being contemplated, while long term extends to the end of the operational time horizon.

Short-term decisions that result in market purchases or surplus sales will by their nature always result in changes in longer term probabilities of the need to either purchase or sell energy, or re-operate to manage system storage.

A simple example is that all else being equal, a decision to buy in the short-term will also increase the probability of spilling in the long term.

Another example is around making Surplus Sales in the high priced summer periods at $50/MWh. At the time of the sale, there would be a risk that the energy instead could have been sold for $100/MWh in the coming winter. Making sales in the high priced summer period also would increase the probability of the need for purchases in the coming fall and winter.

There is also uncertainty associated with a decision to forego purchases or sales. There is always a risk that foregone opportunities to sell (at a lower price) or purchase (at a higher price) will turn out to have been economically beneficial. Using the preceding example, foregoing the $50/MWh sale in the summer may result in only being able to obtain a $35/MWh sale in the winter. In addition, inflows may come in higher than forecast such that the volume of sales should have been higher (thus selling at a lower price), or vice versa.

As shown through the above examples, the trade-off implied in the question that increasing short-term risk always decreases long-term risk, and vice versa, is not straight forward. The Energy Studies models account for the trade-offs between selling now and selling later, or buying now and buying later, and provide the economically optimal price signals over the range of possible outcomes.

6.0 A. CHAPTER 4 – COST OF ENERGY

Reference: COST OF ENERGY
Exhibit B-1, p. 4-17; Appendix DD, p. 9; Exhibit B-16, BCUC IR 309.1
Energy Study objectives

BC Hydro’s response to BCUC IR 309.1 states:

> There is no risk allocated to the shareholder. Through the Cost of Energy Variance accounts, the costs and benefits from the consolidated net revenue from operations are allocated to ratepayers.
>
> BC Hydro manages trade-offs in short-term and long-term risks by modelling the system over a five-year time horizon, which takes into account the longer term impacts of any shorter term benefits or costs.

2.6.4 Please discuss any trade offs in short-term and long-term risks as they relate to long-term hydrothermal scheduling.

RESPONSE:

As described in BC Hydro’s response to BCUC Panel IR 2.6.1, hydrothermal scheduling is a generic term used by SINTEF, the audit consultant, to refer to planning the operation (i.e., scheduling generation). Please refer to BC Hydro’s response to BCUC Panel IR 2.6.3 for a discussion of short-term versus long-term risks.

7.0 A. CHAPTER 4 – COST OF ENERGY

References: COST OF ENERGY
Exhibit B-1, Appendix DD, pp. 9–13; Exhibit B-5;
BCUC IR 31.2, 31.3
Energy Studies – Backtesting

Page 9 of Appendix DD to the Application states "Effective governance is in place over the Energy Studies process."

Page 10 of Appendix DD states "Key areas for improvement include process automation, upgrading legacy software coding for the Peace River model, refining documentation, and periodically backtesting to gain more insights into model performance."

Page 11 of Appendix DD includes the following statements:

- The Market Model was last reviewed externally in 2005. The basic methodology behind the model has been more or less unchanged for many years, but model code was rewritten as part of the Comet Improvement Project implemented in 2016. Model parameters are updated yearly based on the availability of new observations.
- The Peace Model was implemented over 30 years ago and has been extensively tested through years of operational use.
- The current model [Peace Model] does not incorporate a snow state variable which could result in underestimating probabilities for prolonged wet or dry periods when computing water values.
- The methodology used to schedule the Columbia River system (COSTA and MUREO) is appropriate and considered best practice. However, given the complexities of the Columbia River system and the River Treaty, more effort should be put into verifying the results of the implemented models. Verification could be done by benchmarking against a second model which the team is currently developing with a university research group.

2.7.1 Please confirm, or otherwise explain, whether the Peace Model incorporates the impacts of the Site C dam.

RESPONSE:

The first unit at Site C is scheduled to come online in fiscal 2024. The generation from Site C in fiscal 2024 was included in the October 2019 Energy Study, however it was not included in the June 2019 Energy Study that was the basis of

the Evidentiary Update, although it should be noted that fiscal 2024 is outside both the Test Period and the operational time frame.

The construction of Site C requires a minimum five foot buffer below the maximum elevation in Williston Reservoir for three years starting in 2020 to protect the diversion works and the coffer dam. There are also times when Peace River discharges will be held to lower levels such as during September to October 2020. Constraints for construction have been included in the Energy Studies models since March 2014.

7.0 A. CHAPTER 4 – COST OF ENERGY

References: COST OF ENERGY
Exhibit B-1, Appendix DD, pp. 9–13; Exhibit B-5;
BCUC IR 31.2, 31.3
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2.7.2 Please explain the statement that "more effort should be put into verifying the results of the implemented models [COSTA and MUREO]." In your response, please address how the models are considered appropriate and best practice given the current effort put into verifying the results.

RESPONSE:

This answer also provides BC Hydro's response to BCUC Panel IRs 2.7.6, 2.7.7, 2.7.8, 2.7.9, 2.7.10 and 2.7.10.1.

The BCUC Panel has asked a number of questions in the 2.7 series regarding the Energy Studies models and whether they can be relied upon if they cannot be back-tested or otherwise fully validated. These questions were prompted by the Energy Studies Process Internal Audit provided in Appendix DD of the Application.

While the internal audit included some recommendations on benchmarking and back-testing for management to investigate or consider, it is important to note the Energy Studies Process was given a green ranking (i.e., only minor issues identified). The audit concluded that:

- **Key models are appropriate; and**
- **The methodologies applied are in line with leading industry practices.**

As noted in the audit, a "comprehensive process is in place to review the Energy Study results."

This response first defines some of the terms and differences between verification, back-testing, and benchmarking to provide a consistent reference for discussion. Next, the three general types of Energy Studies models are discussed, with a focus on the different forms of validation that are applicable for each particular type of model.

<u>Definition of Terms</u>

Verification **of the models is a general term that includes a number of tasks that collectively provide BC Hydro confidence that its models can be relied upon. Verification includes benchmarking and back-testing, but it also includes other engineering work and ongoing operational review. As operational models, the Energy Studies suite of models must implicitly pass ongoing validity checks by the operations and Powerex staff.**

Back-testing **involves running a model with known historic inputs and comparing the results to historic observations.**

Benchmarking **is the comparison of the results between two models.**

Types of Models

There are three general types of Energy Studies models, and each type of model requires a different form of testing or validation.

Models that Create the Key Input Variables

There have been many Information Requests in this proceeding about the modeling of the key variables (inflow, load, market price) that drive the outcomes in the Energy Studies[1]. The common theme among these models is that they all derive their results from historic weather data (temperature and precipitation).

***Stochastic* models create a probability distribution around a single trace forecast of the input variable (i.e., market price or load). The parameters of the models are derived from historic data, and models are calibrated to ensure that the distribution of the forecast matches the distribution of the historic data[2]. As discussed in BC Hydro's response to BCUC Panel IR 2.7.4, for the market model there is a trade-off between choosing a long enough historic period to capture the range of outcomes and a short enough period to capture recent fundamental changes in the market.**

***The hydrologic model* produces the ensemble inflow forecasts that are used in the Energy Studies to represent the distribution of possible outcomes. This model is also calibrated and tested against historical data. For example, the Peace model was last calibrated in 2010. Data from 1989 to 2004 was used to calibrate the model, and data from 1981 to 1989 was used to check the calibration. This is an example of back-testing. There should be no need to recalibrate the hydrological model unless the physical characteristics of the basin change substantially. Regardless, BC Hydro periodically verifies the results to determine if recalibration is necessary.**

As probabilistic forecasts, there is no expectation that the forecast will be 'right'. It is obviously not realistic in January to predict how much rain will occur on March 1. We do, however, know the average rainfall expected on March 1 and the distribution of possible outcomes around that average based on the historic observations.

What is important for the key input drivers is that in operations BC Hydro checks for biases in the results. For example, does the hydrologic model have a bias of

1 Examples include BC Hydro's response to BCUC IRs 1.31.1, 2.208.1 and 2.209.1

2 The models also downscale the monthly data to sub daily. A statistical analysis of historical data is used to derive the parameters of the regression equations in the model, and the resulting forecasts include the addition of appropriate error terms to match the distribution of historical data.

underestimating the impact of baseflow conditions in December? Since inflows are observed on a daily basis, comparisons of observed data to the forecast provide operational checks on the model parameters and adjustments are applied as necessary to remove any observed bias.

<u>Models that Simulate the BC Hydro System</u>

***Simulation models*[3]**

These apply engineering equations to simulate the mass balance of water in the reservoirs and the conversion of water passing through the turbines to energy. These equations are well understood.

The 'characteristics' in the models, such as volume of storage in the reservoirs and efficiency curves for the turbines, have been thoroughly tested by operation of the system over many years. These characteristics may change when a new unit or generating station is brought into service as operating experience is gained and tests are performed. For example, turbine runners on units 1 through 5 at the GMS Generating Station were upgraded between 2013 and 2015, which resulted in improved efficiency and therefore higher energy production. Initial turbine efficiency curves were theoretical, based on engineering design. Operational tests were performed once the first unit was in service to verify the characteristics, and these values are used in the models.

Benchmarking of simulation models

As described in BC Hydro's response to BCUC IR 1.31.3, a number of alternative models exist that are used as part of BC Hydro's daily and weekly analysis. These models simulate individual parts of the BC Hydro system and can be compared to specific models within the Energy Studies suite of models. These include models for the Kootenay system, Libby Reservoir, the Pend d'Oreille system, the Columbia River in the U.S., the Columbia plants in Canada, and the simulation of the Columbia River constraints.

An as example, the elevation and outflow from Libby Reservoir are forecast from the Energy Studies and from an alternative model, and the results of the two models are compared. While the results of the two models are usually close even though the alternative model uses different logic, the differences in the results are scrutinized to understand how the uncertainty in possible outcomes may impact operations and to improve the Energy Study models or the alternative model.

[3] **SOPHOS and COSTA are the two main simulation models in the suite of Energy Study models.**

<u>Models that Optimize Operation of System Storage</u>

Optimization models:

These are Stochastic Dynamic Programs that optimize the operation of system storage while accounting for the uncertainty in the input variables. These models are back-tested during their development and tested in parallel to other models before being brought into production. The specific approach to optimizing the Peace and Columbia systems is described on page 6 and 7 of Appendix DD and the methodologies are described in the audit as internationally recognized, which led to the audit conclusion that the key models "are appropriate and the methodologies applied are in line with leading industry practices."

Peace model:

The audit states on page 7 that the Peace optimization model has been extensively tested through years of operational use. The audit notes that legacy code is used in the Peace Model and that BC Hydro is working on a replacement model with updated code.

Columbia models:

The models COSTA and MUREO were built together to simulate the constraints associated with the Columbia River Treaty (performed in COSTA), and then use those constraints in a stochastic optimization of BC Hydro's Columbia generation (performed in MUREO).

The audit recognized that the Columbia River system and the nature of operations under the Columbia River Treaty are very complex. A stochastic optimization had never before been successfully designed and implemented under such a unique set of constraints. Some new Stochastic Programming techniques were developed in order to meet the constraints and account for the uncertainty in the system.

During development of the Columbia models, the models were back-tested by rerunning a select number of old Energy Studies. The selected studies were chosen based on months when the BC Hydro system faced significant constraints, such as during the high inflows in fiscal 2013 and the low inflows in fiscal 2011.The Columbia models were also run in parallel with the former Columbia models for a year before retiring the former models. This process helped to build trust in the new models as they did not yet have a track record of being used in operations.

Note that the term "benchmark" in recommendation No. 5 refers to analyzing the quality of the stochastic optimization program MUREO (Stochastic Sampling

Dynamic Program) by comparing it against another stochastic optimization program (in this case, Stochastic Dual Dynamic Program); it does not refer to comparing how well the models describe the operation of the real system. This 'benchmarking' will also be useful for advancing the optimization techniques that could eventually lead to optimizing the two rivers in one unified model instead of maintaining and coordinating the two models.

Conclusion

The audit noted that BC Hydro does not have a regular schedule of back-testing (or benchmarking) in the current Energy Studies Process. It also notes that typically, calculated marginal prices would be compared with market prices to assess model performance, but given there are no market prices for the BC Hydro system this is not possible. Recommendation No. 10 is a general, not specific, recommendation to 'Investigate options for periodic benchmarking or back-testing of key model results.'

As described in the response to this IR, models are back-tested and benchmarked when bringing models from development into production, and there is regular verification of the models though operational use and comparison to other models. This combination of tasks is why the models can be relied upon.

BC Hydro's response to BCUC Panel IR 2.5.6 explains why the historical consolidated net revenue from operations cannot be used for back-testing, and in particular notes that a comparison is not useful without controlling for the variances of the primary drivers of inflow, load, and market prices.

Formal back-testing and benchmarking, which is done prior to any model being brought into production, is a time consuming process. While models can always be improved and there may be benefit in regular formal back-testing and benchmarking, management has to prioritize staff time and resources on the areas viewed as containing the most risk. Since the key input drivers have the largest impact on the outcomes, BC Hydro prioritizes understanding changes in these variables and analyzing for bias.

In 2019, BC Hydro conducted a literature review on benchmarking techniques. BC Hydro is currently working on a longer term plan to address the recommendation in the audit on back-testing and benchmarking.

7.0 A. CHAPTER 4 – COST OF ENERGY

References: COST OF ENERGY
Exhibit B-1, Appendix DD, pp. 9–13; Exhibit B-5;
BCUC IR 31.2, 31.3
Energy Studies – Backtesting

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- The methodology used to schedule the Columbia River system (COSTA and MUREO) is appropriate and considered best practice. However, given the complexities of the Columbia River system and the River Treaty, more effort should be put into verifying the results of the implemented models. Verification could be done by benchmarking against a second model which the team is currently developing with a university research group.

2.7.2 Please explain the statement that "more effort should be put into verifying the results of the implemented models [COSTA and MUREO]." In your response, please address how the models are considered appropriate and best practice given the current effort put into verifying the results.

2.7.2.1 Please discuss the process used in selecting a university research group to develop a benchmarking model. Please discuss whether any other key models, or models used in the Energy Studies, use a benchmarking model in place to verify results.

RESPONSE:

UBC and BC Hydro have a long-standing collaboration for research directed at enhancing the ability of BC Hydro to model and optimize the operation of our hydropower system. This collaboration was established almost 20 years ago. Approximately every three years, BC Hydro evaluates whether or not to continue with the arrangement.

One of the collaborative research projects is developing a Stochastic Dual Dynamic Programming (SDDP) model. Associated with this is related a project to determine the most applicable methods for benchmarking.

Please refer to BC Hydro's response to BCUC Panel IR 2.7.2 for discussion on benchmarking and verification.

7.0 A. CHAPTER 4 – COST OF ENERGY

References: COST OF ENERGY
Exhibit B-1, Appendix DD, pp. 9–13; Exhibit B-5;
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2.7.3 Please discuss how BC Hydro has addressed the report’s key area for improvement of “process automation.”

RESPONSE:

BC Hydro has made a number of improvements to incorporate more automation into the preparation of our Energy Studies. For example, in 2019 we improved the collection and assimilation of external data. To-date, we have focused on achieving automation with the highest value relative to the implementation effort required. We are currently putting together a more comprehensive plan to address the audit recommendations for further process automation.

7.0 A. CHAPTER 4 – COST OF ENERGY

References: COST OF ENERGY
Exhibit B-1, Appendix DD, pp. 9–13; Exhibit B-5;
BCUC IR 31.2, 31.3
Energy Studies – Backtesting

Page 13 of Appendix DD states the following:

- No regular backtesting (or benchmarking) is performed in the current process. Typically, calculated marginal prices would be compared with market prices to assess model performance. Given there are no market prices for the BC Hydro system, this would not be possible. However, actual reservoir operation could be compared to model simulations.
- Backtesting could be easier to perform if the process is further automated as discussed previously.

BC Hydro's response to BCUC IR 31.2 includes the following statements:

- Back testing is not appropriate for the entire Energy Studies process. The BC Hydro system is constantly changing and there are many operational decisions that rely on human action. Therefore, back testing the Energy Study results would not provide useful insight into the quality of the models.
- Back testing has been done on several components of the Energy Studies process in order to calibrate sub-models. In addition, the simulated reservoir elevations are tracked against actual elevations each week. Deviations between the two are explained as part of the weekly operations update.

2.7.4 "The Market Model was last reviewed externally in 2005, however the model code was rewritten in 2016." Please clarify whether the Market Model has been externally reviewed since 2016. If so, please provide excerpts from the relevant external report. Alternatively, please identify any key areas of concern or improvement.

RESPONSE:

There has been no external review of the Market Model since 2016, although the recent internal audit performed in October 2018 included external reviewers from SINTEF.

The Market Model provides forecasts of prices in external markets, which form the basis for valuing energy within the BC Hydro system. This model is a statistical model, using inferred historic observed relationships between driving variables to forecast the range and trajectory of prices. While the basic methodology behind

the model hasn't changed, the Market Model parameters are updated yearly based on new price data.

While the 2016 version of the Market Model contains many improvements over the previous version, BC Hydro's primary area of focus for improvements within the model relate to using forward price curves as a forecast of eventual spot prices. The challenges related to this include:

- **The use of historic data to estimate the regression relationships in the statistical model requires a trade-off between choosing a long enough historic period to capture the range of outcomes and a short enough period to capture recent fundamental changes in the market;**
- **The fact that a single trace forward price curve cannot anticipate other scenarios of fundamental changes in energy markets that can be driven by policy or economic developments; and**
- **Changing market conditions as some load serving entities are increasingly seeking forward supply commitments to meet their expected peak loads and to manage operations, meet formal resource adequacy requirements, and secure energy products with specific environmental attributes to comply with clean energy policies.**

7.0 A. CHAPTER 4 – COST OF ENERGY

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- Back testing has been done on several components of the Energy Studies process in order to calibrate sub-models. In addition, the simulated reservoir elevations are tracked against actual elevations each week. Deviations between the two are explained as part of the weekly operations update.

2.7.5 Please identify the most recent dates when reviews for those models where backtesting is considered appropriate were last performed, particularly with respect to each of the Peace Model and models for the Columbia River System (i.e. COSTA and MUREO). In your response, please identify whether each model was reviewed internally or externally.

RESPONSE:

COSTA is a stochastic rule-based simulation model that forecasts the constraints under the Columbia River Treaty. Because of the rule-based nature of the Columbia River Treaty and the COSTA model, back-testing is not appropriate. However, it is regularly benchmarked against the official Columbia River Treaty model that is used jointly by Bonneville Power, the US Army Corp of Engineers,

and BC Hydro to calculate the Columbia River Treaty operational constraints each month.

The Peace optimization model was last back-tested in 2005 and was reviewed externally in 1998. As described in the Energy Studies Process Internal Audit (Appendix DD in the Application), 'The Peace model was implemented over 30 years ago and has been extensively tested through years of operational use'.

MUREO was back-tested as part of the MUREO development project that was completed in 2016. There has been no external review of this model, although the Energy Studies Process Internal Audit included external reviewers from SINTEF.

The system simulation model (SOPHOS) simulates the Peace and Columbia systems. Complete back-testing of SOPHOS was last performed in 2016 as part of the SOPHOS development project. There has been no external review of this model, although the Energy Studies Process Internal Audit included external reviewers from SINTEF.

Please also refer to BC Hydro's response to the BCUC Panel IR 2.7.2 for a discussion of verification and back-testing.

7.0 A. CHAPTER 4 – COST OF ENERGY

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- Backtesting could be easier to perform if the process is further automated as discussed previously.

BC Hydro's response to BCUC IR 31.2 includes the following statements:

- Back testing is not appropriate for the entire Energy Studies process. The BC Hydro system is constantly changing and there are many operational decisions that rely on human action. Therefore, back testing the Energy Study results would not provide useful insight into the quality of the models.
- Back testing has been done on several components of the Energy Studies process in order to calibrate sub-models. In addition, the simulated reservoir elevations are tracked against actual elevations each week. Deviations between the two are explained as part of the weekly operations update.

2.7.6 Please discuss the frequency of backtesting, and what backtesting scheduling has been established for those models where backtesting is considered appropriate.

RESPONSE:

Please refer to BC Hydro's response to BCUC Panel IR 2.7.2.

7.0 A. CHAPTER 4 – COST OF ENERGY

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- Backtesting could be easier to perform if the process is further automated as discussed previously.

BC Hydro’s response to BCUC IR 31.2 includes the following statements:

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- Back testing has been done on several components of the Energy Studies process in order to calibrate sub-models. In addition, the simulated reservoir elevations are tracked against actual elevations each week. Deviations between the two are explained as part of the weekly operations update.

2.7.7 Please explain how a model can be relied on if it cannot be backtested or otherwise fully validated.

RESPONSE:

Please refer to BC Hydro’s response to BCUC Panel IR 2.7.2.

7.0 A. CHAPTER 4 – COST OF ENERGY

References: COST OF ENERGY
Exhibit B-1, Appendix DD, pp. 9–13; Exhibit B-5;
BCUC IR 31.2, 31.3
Energy Studies – Backtesting

BC Hydro's response to BCUC IR 31.3 states:

> The major results of the Energy Studies are discussed each week within BC Hydro's Generation System Operations Group and with Powerex, and there are regular comparisons to previous results. A number of alternative models exist that are used as part of BC Hydro's daily and weekly analysis. The results of these alternative models are also used to verify that the Energy Studies models are working as intended.

2.7.8 Please explain why major results of Energy Studies, and comparisons to previous results, are discussed weekly if backtesting is not performed on a regular basis.

RESPONSE:

BC Hydro reviews the forecasts of key drivers to the Energy Study models weekly to see how they compare to those used for the most recent Energy Study to see how they would impact the major results from the Energy Study.

Backtesting is a different process which involves running a model with known historic inputs and comparing the results to historic observations. For more information about backtesting, please refer to BC Hydro's response to BCUC Panel IR 2.7.2.

7.0 A. CHAPTER 4 – COST OF ENERGY

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BC Hydro's response to BCUC IR 31.3 states:

> The major results of the Energy Studies are discussed each week within BC Hydro's Generation System Operations Group and with Powerex, and there are regular comparisons to previous results. A number of alternative models exist that are used as part of BC Hydro's daily and weekly analysis. The results of these alternative models are also used to verify that the Energy Studies models are working as intended.

2.7.9 Please expand on what is meant by the statement "working as intended." In your response, please address whether this refers to meeting load requirements, or maximizing risk-neutral long-term net revenue.

RESPONSE:

A suite of models supports the Energy Studies. Each model has a different purpose and the statement "working as intended" is different for each model. Please refer to BC Hydro's response to BCUC Panel IR 2.7.2 for a description of how the models are verified.

7.0 A. CHAPTER 4 – COST OF ENERGY

References: COST OF ENERGY
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BCUC IR 31.2, 31.3
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> The major results of the Energy Studies are discussed each week within BC Hydro’s Generation System Operations Group and with Powerex, and there are regular comparisons to previous results. A number of alternative models exist that are used as part of BC Hydro’s daily and weekly analysis. The results of these alternative models are also used to verify that the Energy Studies models are working as intended.

2.7.10 Please discuss whether using the results of alternative models to the Energy Studies substitutes for back testing the models that comprise the monthly Energy Studies.

RESPONSE:

Please refer to BC Hydro’s response to BCUC Panel IR 2.7.2.

7.0 A. CHAPTER 4 – COST OF ENERGY

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> The major results of the Energy Studies are discussed each week within BC Hydro's Generation System Operations Group and with Powerex, and there are regular comparisons to previous results. A number of alternative models exist that are used as part of BC Hydro's daily and weekly analysis. The results of these alternative models are also used to verify that the Energy Studies models are working as intended.

2.7.10 Please discuss whether using the results of alternative models to the Energy Studies substitutes for back testing the models that comprise the monthly Energy Studies.

2.7.10.1 Please explain whether alternative models, which are used to verify that the Energy Studies models are working as intended, optimize the system in the short-run better than the monthly Energy Studies and if so, why.

RESPONSE:

Please refer to BC Hydro's response to BCUC Panel IR 2.7.2 for a description of how the models are verified, and BC Hydro's response to BCUC Panel IR 2.5.1 for a description of short-term models (intra-month).

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 9-10 of the Application states "Consistent with past practice, current operating costs and provisions are directly assigned or allocated to the transmission function based on cost causation."

However, BC Hydro's response to BCUC IR 267.1 states "Methodologies from the 2016 cost of service study [COSS] may not be directly applicable to the fiscal 2020 to fiscal 2021 Transmission Revenue Requirement given changes to BC Hydro's business and financial model (e.g., changes to regulatory accounts and cost definitions)."

2.8.1 Please reconcile the two statements above. Specifically, please explain how costs can be allocated consistent with past practice, yet the previous COSS may not be directly applicable in the test period.

RESPONSE:

The statement from Page 9-10 of the Application is referring to a comparison between the Fiscal 2020 to Fiscal 2021 Transmission Revenue Requirement and the Transmission Revenue Requirements that were prepared as part of previous revenue requirements applications. The Transmission Revenue Requirement cost causation studies have been prepared using consistent principles for the same specific purposes, namely: (i) they are inputs to development of the financial model forecasts that are used to establish BC Hydro's overall revenue requirements; and (ii) they are used to establish BC Hydro's unbundled OATT Rates.

The Fiscal 2020 to Fiscal 2021 Transmission Revenue Requirement was developed on a forecast basis based BC Hydro's business organization, financial practices and financial model at the time of its development in fiscal 2019, with consideration to expected changes during the test period.

The statement in BC Hydro's response to BCUC IR 2.267.1 refers to a comparison between the Fiscal 2020 to Fiscal 2021 Transmission Revenue Requirement cost causation study, as discussed above, and BC Hydro's 2016 cost of service study. BC Hydro's 2016 cost of service study used the financial model from the Fiscal 2016 Revenue Requirements Application and had a different purpose than a Transmission Revenue Requirement study. BC Hydro's 2016 cost of service study allocated BC Hydro's total revenue requirement to our bundled rate classes (e.g., Residential, Transmission Service) to inform BC Hydro's 2015 Rate Design Application.

BC Hydro's 2016 cost of service study was based on the fiscal 2016 plan financial model, which was based on BC Hydro's business organization and financial practices as they existed in fiscal 2014 when it was prepared. Transmission costs that were used in the 2016 cost of service study would therefore directly relate to the calculation of the transmission revenue requirement that informed fiscal 2016 plan version of the financial model.

BC Hydro has undergone restructuring and changes to its financial practices since the fiscal 2016 plan version of the financial model on which the 2016 cost of service study was based. These changes include a corporate restructuring to a plan, build, operate, support organization structure (i.e., with no functionalized business units) and full adoption of International Financial Reporting Standards. These are not reflected in the 2016 cost of service study but are reflected in the Fiscal 2020 to Fiscal 2021 Transmission Revenue Requirement.

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 9-10 of the Application states "Consistent with past practice, current operating costs and provisions are directly assigned or allocated to the transmission function based on cost causation."

However, BC Hydro's response to BCUC IR 267.1 states "Methodologies from the 2016 cost of service study [COSS] may not be directly applicable to the fiscal 2020 to fiscal 2021 Transmission Revenue Requirement given changes to BC Hydro's business and financial model (e.g., changes to regulatory accounts and cost definitions)."

2.8.2 Please clearly identify which 2016 COSS items are not directly applicable in this test period and how BC Hydro has allocated these costs in each of the fiscal 2020 and 2021 test periods for the Transmission Revenue Requirement (TRR).

RESPONSE:

Please refer to BC Hydro's response to BCUC Panel IR 2.8.1, in which we explain how the Fiscal 2020 to Fiscal 2021 Transmission Revenue Requirement and the 2016 Cost of Service Study were prepared for different purposes using different data sources.

The Fiscal 2020 to Fiscal 2021 Transmission Revenue Requirement is used only to allocate transmission capacity costs to the OATT Rates for recovery from OATT customers in the test period, including to BC Hydro as a Network Integration Transmission Services (NITS) customer and through internal Point-To-Point Transmission Service costs. In cost-of-service terms, these are forecast costs that have been functionalized to Transmission and classified as 100 per cent capacity.

In contrast, the 2016 Cost of Service Study considered a much broader set of costs. The transmission capacity costs allocated to BC Hydro were just one component of these costs, and were included in the total capacity (demand) costs that are allocated, along with energy and customer related costs, to the various

customer classes as defined in BC Hydro Electric Tariff. For this reason, and as listed in the table included in BC Hydro's response to BCUC IR 2.267.1 several of the methodology topics used in the 2016 Cost of Service Study do not apply to the Fiscal 2020 to Fiscal 2021 Transmission Revenue Requirement.

With specific reference to the 2016 Cost of Service Study (as contained in Order G−47−16), the following table is based on the table of contents of the 2016 Cost of Service Study and summarizes the general applicability of the contents of each of the schedules in the 2016 Cost of Service Study to a Transmission Revenue Requirement that is prepared using the same data sources.

In all cases where BC Hydro states that a schedule is not applicable, it is not applicable in the fiscal 2020 to fiscal 2021 test period, nor would it be applicable in any other test period for which a Transmission Revenue Requirement is prepared. In in all cases where BC Hydro states that a schedule is applicable or partially applicable, the applicability is subject to the clarifications provided in BC Hydro's response to BCUC Panel IR 2.8.1:

2016 COSS Schedule	Description	Applicability to Transmission Revenue Requirement (TRR)
1.0	Functionalization Details	Applicable. The TRR represents all costs that are functionalized to Transmission and functionalization methodologies used are intended to be consistent between the COSS and TRR.
2.0	Classification of Generation Function	Not applicable. Costs functionalized to Generation are not included in the TRR.
2.1	Classification of Transmission Function	Applicable. Costs that have been functionalized to Transmission are classified as 100 per cent capacity (demand) in the TRR as they are in the COSS. The OATT rates recover transmission capacity costs.
2.2	Classification of Distribution Function	Not applicable. Costs that have been functionalized to Distribution are not included in the TRR.
2.3	Classification of Customer Care	Not applicable. Costs that have been functionalized to Customer Care are not included in the TRR.
3.0	Allocation of Generation to Rate Classes	Not applicable. Generation allocations allocate demand and energy to BC Hydro's bundled electricity rates under the Electric Tariff and not to the OATT rates.
3.1	Allocation of Transmission to Rate Classes	Not applicable. Transmission allocations allocate demand costs to BC Hydro's bundled electricity rates under the Electric Tariff and not to the OATT rates.

2016 COSS Schedule	Description	Applicability to Transmission Revenue Requirement (TRR)
3.2	Allocation of Distribution to Rate Classes	Not applicable. Distribution allocations allocate demand, energy and customer related costs to BC Hydro's bundled electricity rates under the Electric Tariff and not to the OATT rates.
3.3	Allocation of Customer Care Costs	Not applicable. Customer Care allocations allocate customer care costs to BC Hydro's bundled electricity rates under the Electric Tariff and not to the OATT rates.
4.0	Summary of Costs by Function & R/C Ratios	Only the Total Transmission Demand Related Costs are applicable as these are determined from the same data sources as the TRR. All other costs, the distribution among rate classes and the Revenue:Cost ratios are not applicable. The OATT rates are established based on a 100 per cent Revenue:Cost Ratio.
4.1	Summary of Costs by Classification	Only the Total Transmission Demand Related Costs are applicable as these are determined from the same data sources as the TRR. All other demand costs and all energy and customer related costs, as well as the distribution among rate classes are not applicable to the TRR.
4.2	Summary of Costs by Allocators	Not Applicable. The allocation of demand costs based on continuous peak / non continuous peak allocators, and any allocation of energy or customer costs are not applicable to the TRR.
5.0	Energy Allocators	Not Applicable. The allocation of energy costs is not applicable to the TRR.
5.1	Demand Allocators	Not Applicable. The allocation of demand costs based on continuous peak / non continuous peak allocators is not applicable to the TRR.
5.2	Distribution Customer Allocators	Not applicable. Only Transmission costs are considered in the TRR.
5.3	Customer Care Allocators	Not applicable. Only Transmission costs are considered in the TRR.
5.4	Transformer Allocators	Not applicable. Only Transmission costs are considered in the TRR.
6.0	Distribution Classification by Sub-Functionalization	Not applicable. Only Transmission costs are considered in the TRR.

2016 COSS Schedule	Description	Applicability to Transmission Revenue Requirement (TRR)
6.1	**Rate Base**	**Applicable. Rate base is used to functionalize certain costs to Transmission for inclusion in the TRR.**

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 of Exhibit B-19 states "the full implementation of IFRS 16, discussed further in Appendix F, shifts costs from IPPs and Long-Term Commitments (Cost of Energy) to Amortization and Finance Charges."

Schedule 3.4 of Appendix A to Exhibit B-19 (Evidentiary Update) shows the following increases to the Transmission Revenue Requirement (TRR) in each of F2020 and F2021:

(In $ million)	F2020	F2021
Increase in Finance Charges Allocated to TRR (Line 4)	$20.7	$18.6
Increase in Total TRR (Line 28)	43.4	42.2

2.8.3 Please calculate the proportion of the increase in finance charges allocated to the TRR that are a result of costs that were previously classified as IPP Capital Lease costs under IFRS 16.

RESPONSE:

Please see the table below.

	(In $ million)	App. A Reference	Fiscal 2020 Plan	Fiscal 2020 Update	Fiscal 2020 Diff	Fiscal 2021 Plan	Fiscal 2021 Update	Fiscal 2021 Diff
1	IPP Capital Leases (IFRS 16 Impact)	8.0 L15	4.2	48.4	44.3	2.8	46.1	43.3
2	Portion of Rate Base (Transmission)	8.0 L34	32.0%	33.2%		31.6%	32.7%	
3	IPP Capital Leases (IFRS 16 Impact) allocated to TRR		1.3	16.1	14.7	0.9	15.1	14.2
4	Current Finance Charges	3.4 L4	223.3	243.9	20.7	209.0	227.6	18.6
5	Portion of IFRS 16 Impact on Finance Charges Increase in TRR	L3 / L4			71%			76%

As shown on line 5 above, the proportion of the increase in finance charges allocated to the Transmission Revenue Requirement resulting from Electricity Purchase Agreements that are accounted for as Leases under IFRS 16 is 71 per cent in fiscal 2020 and 76 per cent in fiscal 2021.

The fiscal 2020 and fiscal 2021 impacts of the change from IAS 17 to IFRS 16 attributable to Electricity Purchase Agreements are shown in BC Hydro's response to AMPC IR 4.3.1.

In responding to this information request, BC Hydro noticed a mistake in its response to BCUC IR 2.267.1. In that response, we state that "…zero per cent of IPP Capital Lease Costs have been functionalized to Transmission in the TRR." As noted above, a portion of finance charges related to Energy Purchase Agreements that are accounted for as leases under IFRS 16 have been functionalized to Transmission using rate base for the Test Period, consistent with BC Hydro's practice for functionalizing finance charges in revenue requirements applications. BC Hydro revised its response to BCUC IR 2.267.1 in Exhibit B-12-2 filed on January 17, 2020.

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 of Exhibit B-19 states "the full implementation of IFRS 16, discussed further in Appendix F, shifts costs from IPPs and Long-Term Commitments (Cost of Energy) to Amortization and Finance Charges."

Schedule 3.4 of Appendix A to Exhibit B-19 (Evidentiary Update) shows the following increases to the Transmission Revenue Requirement (TRR) in each of F2020 and F2021:

(In $ million)	F2020	F2021
Increase in Finance Charges Allocated to TRR (Line 4)	$20.7	$18.6
Increase in Total TRR (Line 28)	43.4	42.2

2.8.4 Please discuss how the application of IFRS 16 impacts BC Hydro's business and financial models as they relate to the TRR.

RESPONSE:

The implementation of IFRS 16 impacted the Transmission Revenue Requirement (TRR) as it resulted in changes to Electricity Purchase Agreements which resulted in a higher allocation of Finance Charges to the TRR.

As discussed in Appendix F (Table F-2) of the Evidentiary Update, the impacts of IFRS 16 on Electricity Purchase Agreements in the Test Period were $16.6 million in fiscal 2020 and $15.5 million in fiscal 2021.

The resulting impact to the TRR is summarized below. As changes in Cost of Energy and Amortization are fully allocated to Customer Care, only the allocation of Finance Charges impacted the TRR. Please refer to BC Hydro's response to BCUC Panel IR 2.8.3 for the calculation of the allocation of the finance charges to TRR.

	($ million)	Fiscal 2020	Impact to TRR	Fiscal 2021	Impact to TRR
1	Cost of Energy	(86.4)	-	(87.7)	-
2	Amortization	58.8	-	59.9	-
3	Finance Charges	44.3	14.7	43.3	14.2
4	**Net Impact**	**16.6**	**14.7**	**15.5**	**14.2**

The amounts shown in the “Impact to TRR” columns above match the amounts in the “Diff” columns on line 3 of the table included in BC Hydro’s response to BCUC Panel IR 2.8.3.

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 of Exhibit B-19 states "the full implementation of IFRS 16, discussed further in Appendix F, shifts costs from IPPs and Long-Term Commitments (Cost of Energy) to Amortization and Finance Charges."

Schedule 3.4 of Appendix A to Exhibit B-19 (Evidentiary Update) shows the following increases to the Transmission Revenue Requirement (TRR) in each of F2020 and F2021:

(In $ million)	F2020	F2021
Increase in Finance Charges Allocated to TRR (Line 4)	$20.7	$18.6
Increase in Total TRR (Line 28)	43.4	42.2

2.8.4 Please discuss how the application of IFRS 16 impacts BC Hydro's business and financial models as they relate to the TRR.

2.8.4.1 Please discuss what methodologies from the 2016 COSS, if any, may or may not be directly applicable to the fiscal 2020 to fiscal 2021 Transmission Revenue Requirement as a result of the application of IFRS 16.

RESPONSE:

There is no impact on the methodologies from the 2016 COSS for allocating costs to the Transmission Revenue Requirement as a result of the adoption of IFRS 16.

The criteria for determining whether a lease exists and is recognized on the balance sheet and the measurement of a lease have changed as a result of the adoption of the new IFRS Leases standard IFRS 16. The adoption of IFRS 16 has resulted in three new Electricity Purchase Agreements being recognized as leases on the balance sheet and three capital leases under the previous standard (IAS 17) being removed from the balance sheet.

Under both Leases standards, three Electricity Purchases Agreements are recognized on the balance sheet and the costs of the agreements are expensed not as cost of energy but as finance charges and depreciation under both standards with a portion classified as operating expenses and taxes under the previous standard. Although the amounts recorded under the two Leases standards differ, the classification of the expenses associated with Electricity Purchase Agreements recognized on the balance sheet is substantially consistent. Therefore, there is no impact on the methodologies from the 2016 COSS for allocating costs to the Transmission Revenue Requirement.

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.

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.

In the mid-1990s, there was a general trend in the North American electricity industry to introduce competition into aspects of the electricity market. At the wholesale level, the main reform was to separate the functions of electricity generation and transmission in order to create a competitive market for generation, coupled with open-access to transmission systems to connect generation to potential customers within a given region. By 1998, both California and Alberta had introduced independent system operators to take over responsibility for the operation of the grid (what are now referred to as balancing authority and transmission service provider functions) from vertically integrated utilities and to establish new organized wholesale market platforms accessible to generators and load serving entities for the purchase and sale of electricity. More broadly, the US Federal Energy Regulatory Commission (FERC) required the adoption of the Open Access Transmission Tariff (OATT) via Orders 888 & 889 for jurisdictional utilities that retained operational control over their transmission facilities.

At the retail level, some states and provinces began adopting retail customer choice programs.

In British Columbia, there was some pressure for deregulation as well. There were several policy reviews undertaken, including by the Commission (Jaccard Task Force), with regard to market reform. In the end, BC Hydro customers were generally supportive of BC Hydro, as a regulated crown corporation, operating a vertically integrated electric system for the benefit of its ratepayers and shareholder. However, BC Hydro did recognize an opportunity for expanding trade within the U.S. (rather than just at the B.C./U.S. border) via its wholly owned subsidiary Powerex (BC Power Exchange Corporation at the time). In order for Powerex to gain access to U.S. transmission systems and the ability to transact at market based rates within the U.S., BC Hydro needed to adopt its own open access transmission tariff in order to meet FERC's requirement for comparable and non-discriminatory access to transmission facilities.

In response, BC Hydro applied to the Commission for approval of its Wholesale Transmission Services (WTS) Tariff in 1996/1997 in order to bring the Terms and Conditions applicable to BC Hydro wholesale transmission service in line with industry standards as established by FERC. In its amended Wholesale Transmission Services application of June 1997, BC Hydro removed certain provisions of the original application that were non-standard in order to make the application comparable with FERC's *pro forma* OATT. As discussed in BC Hydro's response to BCUC IR 1.162.1, BCUC Order No. G-43-98 approved the Wholesale

Transmission Service (WTS) tariff, including key rate design elements. The resulting Trade Income arising from Powerex's participation in the U.S. markets has provided ongoing benefits to BC Hydro's ratepayers over the past 20 years.

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
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> 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.

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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.

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.

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

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.**

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
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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.

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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.

2.8.5.2 Please list the OATT amendments since 1998 and describe how they address which "specific OATT rates and rate design issues."

RESPONSE:

BC Hydro provides the requested information in the table below. The table includes the BCUC Orders that were listed in BC Hydro's response to BCUC IR 1.162.1. Please note that all BCUC Orders that are relevant to the way the Transmission Revenue Requirement is allocated to the OATT rates were included in BC Hydro's response to BCUC IR 1.162.1. BC Hydro has not included previous revenue requirements applications in the table below, each of which resulted in amendment to the OATT rates.

Application and Rates Established	BCUC Order No.
1997 BC Hydro Wholesale Transmission Service Tariff Application **Established BC Hydro's tariff for Wholesale Transmission Service (WTS) based on FERC Order No. 888.** **Established key rate design concepts including:** • **Network Integration Transmission Service (NITS) rate design;** • **Point-To-Point Transmission Service (PTP) rate design;** • **Functionalization of Generation Related Transmission Assets; and** • **Functionalization of demand side management**	**G-43-98**
1998 BC Hydro Locationally Efficient Price Signals **Established locationally efficient price signals for PTP in response to BCUC Letter No. L-76-98 based on a declaratory order from FERC that such pricing signals would be acceptable.** • **Amended Long-Term and Short-Term rates based on locationally efficient price signals.**	**G-116-98**
2004 British Columbia Transmission Corporation (BCTC) Application for an Open Access Transmission Tariff and BC Hydro Interconnected Operations Services to BCTC **Established the OATT and key rate design concepts including:** • **BCTC as transmission provider under the OATT;** • **Postage stamp rates for Long Term Firm PTP service;** • **Affirmed the PTP and NITS rate design; and** • **Use of the Maximum Capacity Supply billing determinant to establish the Long Term PTP rate.**	**G-58-05**
2004 BC Hydro/ BCTC – Standards of Conduct Application • **Established Standards of Conduct provisions for Transmission related information as originally described in FERC Order No. 889.**	**G-13-05**
2005 BCTC Dynamic Scheduling Application • **Established that dynamic scheduling could be used to schedule exports on Long-Term PTP reservations.**	**G-12-06**

Application and Rates Established	BCUC Order No.
2006 BCTC Loss Compensation Service Application • **Established Loss Compensation Service under OATT Rate Schedule 09 by which customers could opt to purchase an ancillary service to compensate for real power losses under Rate Schedule 10, instead of self-supplying losses.** • **Approved Rate included an expiry provision requiring ongoing re-approval.**	**G-18-06** **G-38-07** **G-13-09** **G-33-10** **G-192-10** **G-33-11** **G-16-12** **G-59-13**
2006 BCTC Network Economy and Open Access Transmission Tariff Application • **Approval of a Negotiated Settlement that established Network Economy Service used to supply Network Load from non-designated resources.**	**G-127-06**
2007 BCTC Application for Contingency and Spinning Reserve Tariff and Mixed Wheelthrough Tariff **Established:** • **Spinning Reserve transmission service;** • **Contingency Reserve transmission service; and** • **Mixed Class Wheelthrough transmission service (Attachment Q-4).**	**G-89-07**
2008 BCTC OATT Amendments Application **Addressed major reforms to the FERC *pro forma* OATT in FERC Order No. 890, including:** • **Established time of use Short Term PTP pricing principles;** • **Established 480 MW Firm Transmission Service limit on BCHA - AESO Path;** • **Established Attachment K Transmission Planning Principles; and** • **Additional housekeeping amendments.**	**G-102-09** **G-103-09**
2009 BCTC Application for a Certificate of Public Convenience and Necessity (CPCN) for the Market Operations and Development (MOD) Project • **Approved the implementation of a consolidated business system to allow BC Hydro to meet evolving customer service needs, and technological and regulatory changes in the delivery of its services under the OATT.**	**C-6-09A**

Application and Rates Established	BCUC Order No.
2010 BC Hydro Open Access Transmission Tariff Application **Amended the OATT, tariff supplements and rate schedules to reflect the integration of BC Hydro and BCTC.** • **Established BC Hydro as Transmission Provider under the OATT; and** • **Additional amendments as required due to the adoption of Mandatory Reliability Standards in British Columbia.**	**G-192-10**
2011 BC Hydro Tariff Supplement No. 81 AltaGas Northwest Projects Umbrella Agreement. • **Established a rate based on BC Hydro / AltaGas Northwest Projects Umbrella Agreement related to the construction of the Northwest Transmission Line under section 7(1) of the *Clean Energy Act.***	**G-20-11**
2011 BC Hydro Amendment of Attachment C of the Open Access Transmission Tariff • **Established the methodology for calculation of Available Transfer Capability on the BC Hydro system in accordance with reliability standards.**	**G-185-11**
2011 BC Hydro Revised OATT Attachment K - Transmission Planning Process • **Amended the Transmission Planning Process for BC Hydro's Transmission System.**	**G-43-12**
2013 BC Hydro 2013 OATT Amendments Application • **Amendments to Transmission Planning Process in response to FERC Order No. 1000; and** • **Additional housekeeping amendments.**	**G-59-13**
2013 BC Hydro FERC Order No. 764 Amendments Application **Amended the OATT to reflect FERC Orders No. 764 and 764-A which were intended to remove barriers to the integration of variable energy resources (VER).** • **Established intra-hour scheduling of energy on Firm and Non-Firm PTP Transmission Services; and** • **Amendments to the Standard Generator Interconnection Procedures to define VERs and require VERs to provide certain meteorological data for the purpose of power production forecasting.**	**G-180-13**

Application and Rates Established	BCUC Order No.
2013 BC Hydro Application to Replace S&P Dow Jones Mid-Columbia Indices **Amended the Mid-Columbia index used as a market proxy in the establishment of certain OATT rates due to discontinuation of the Standard and Poors Dow Jones index:** • **Rate Schedule 06: Energy Imbalance Service;** • **Rate Schedule 09: Loss Compensation Service;** • **Tariff Supplement 80: Network Economy;** • **Attachment A: Umbrella Agreement for Short-Term Firm or Non-Firm Point-To-Point Transmission Service; and** • **Attachment B: Form of Service Agreement for Long-Term Firm Point-To-Point Transmission Service.**	**G-214-13**
2015 BC Hydro Application to Replace Mid-Columbia Electricity Price Indices **Amended the Mid-Columbia index used as a market proxy in the establishment of certain OATT rates to replace the Platts, McGraw Hill Financial Mid-Columbia index with the equivalent Intercontinental Exchange Inc. index:** • **Rate Schedule 06: Energy Imbalance Service;** • **Rate Schedule 09: Loss Compensation Service;** • **Tariff Supplement 80: Network Economy; and** • **Application included similar changes to Mid-Columbia index used in electric tariff rate schedules and tariff supplements.**	**G-36-15**
BC Hydro Tariff Supplement No. 80 Amendments Application **Amended the OATT Network Economy Service provisions due to the decommissioning of Burrard Generating Station. Included additional housekeeping amendments to the OATT:** • **Amended trigger price economic test established in TS 80;** • **Amended the time of day that the market price is extracted for the economic test so that it could be accomplished before close of business;** • **RS 07 Spinning Reserve Service - aligned reserve quantities with reliability standards; and** • **RS 08 Supplemental Reserve Service - aligned reserve quantities with reliability standards.**	**G-158-15**

Application and Rates Established	BCUC Order No.
2017 BC Hydro Application to Amend Foreign Exchange Rates for Electric Tariff and Open Access Transmission Tariff **Amended the Foreign Exchange rate references in the OATT due to the discontinuation of the Bank of Canada Noon Rate.** • **Attachment A - Umbrella Agreement for Short-Term Firm** • **Non-Firm Point-To-Point Transmission Service**	**G-54-17**
2017 BC Hydro Application for Approval of Amended Reassignment Agreements **Implemented previously approved agreements and established a single form of agreement for all reassignments of PTP Transmission service:** • **Eliminated Attachment A-1 which applied to reassignment of Short-Term PTP Transmission Service.** • **Amended Attachment B-1 to make it applicable to reassignment of both Long-Term and Short-Term PTP Transmission Service.**	**G-197-17**
2017 Dynamic Scheduling Amendments Application **Established the use of Dynamic Scheduling on all PTP import and export reservations to allow customers to participate in new and growing markets.** • **Amended Attachment Q-1 to allow dynamic scheduling on any priority of transmission reservations for both imports and exports of energy.**	**G-20-18**
2018 BC Hydro Application to Amend Rate Schedule 09 – Loss Compensation Service • **Amended RS 09 to remove expiry date to improve regulatory efficiency by not requiring ongoing re-approval.**	**G-111-18**

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."

2.8.6 Please generally describe how BC Hydro's transmission system has changed since 1998. As part of your response, please address the following topics: reliability, capacity, number of customers.

RESPONSE:

BC Hydro interprets this information request to be related to its use and build-out of the transmission system to serve its domestic load customers under the electric tariff, and provides the requested customer and reliability information on this basis. BC Hydro remains the only Network Integration Transmission Service (NITS) customer and reserves the transmission capacity required for it to serve domestic load customers from designated network resources using the NITS provisions of the OATT as discussed in BC Hydro's response to BCUC Panel IR 2.12.1.1. The use of total dependable capacity including planned resources that is used to establish the Maximum Capacity Supply billing determinant for Point-To-Point Transmission Service was discussed in BC Hydro's response to BCUC IRs 1.166.3 and 1.166.4. Growth in the dependable capacity requires changes to the Transmission system in order to accommodate overall growth in BC Hydro's system. The Point-To-Point Transmission Service rate determination is reflective of this overall growth, and hence remains valid.

Physical Changes to the BC Hydro Transmission System

Since 1998 there have been changes to the BC Hydro transmission system to meet the following system needs:

- **Increasing inter-region bulk transmission capability, for example through the Interior to Lower Mainland (ILM) Transmission Project;**
- **Accommodating new generation interconnections, including IPPs, for example by adding the new Upper Harrison Terminal Station; and**
- **Reliably serving forecasted load growth in the regional transmission systems, for example through completing the Central Vancouver Island (CVI) Transmission Project.**

Generally, the changes to the transmission system since 1998 resulted in:

- **Increased line length of the transmission system to 20,385 kilometres in 2019 from 17,811 kilometres in 1998; and**
- **A total of 42 new substations (60 kilovolt to 500 kilovolt) connected to the BC Hydro transmission system since 1998.**

These transmission changes were implemented through major transmission reinforcements, including the addition of new transmission circuits, the addition of new substations (including series capacitor stations) and other system upgrades such as installing new station devices in the existing substations, reconfiguring transmission circuits and uprating circuits.

The major transmission reinforcements were implemented through a number of capital projects with BCUC approval as part of revenue requirement applications or Certificates of Public Convenience and Necessity (CPCN) applications or applications under Section 44.2 of the *Utilities Commission Act* (e.g., Dawson Creek – Chetwynd Area Transmission (DCAT) Project CPCN application), except for projects that were exempt from BCUC review (e.g., Northwest Transmission Line (NTL) Project, which was exempt from BCUC review under the *Clean Energy Act)*.

Table 1 lists some of the major transmission projects completed since 1998.

Table 1: Major Transmission Projects from 1998 to 2019 (230 kV and above)

In Service Year	Transmission Project Description
2004	230 kV Cathedral Square to Horne Payne Cable Project
2008	Vancouver Island Transmission Reinforcement (VITR) Project
2010	Central Vancouver Island (CVI) Transmission Project
2012	Columbia Valley Transmission (CVT) Project
2014	Vancouver City Central Transmission (VCCT) Project
2014	Northwest Transmission (NTL) Project
2015	Interior to Lower Mainland (ILM) Transmission Project
2016	Dawson Creek – Chetwynd Area Transmission (DCAT) Project

In addition, a 500 kilovolt transmission circuit clearance upgrading project on the B.C.-U.S. inter-tie, 5L51/5L52 Thermal Upgrade, was completed in 2010 to increase the Western Electricity Coordinating Council Path 3 Ratings.

Table 2 provides a list of the major new substations (230 kilovolts and above) added to BC Hydro transmission system since 1998:

Table 2: Major New Substations Added from 1998 (230 kV and above)

In-Service Year	Station Code	Station Description
2005	VAS	500 kV Vaseux Terminal Station
2006	FCN	230 kV Function Junction Substation
2006	GUI	500 kV Guichon Capacitor Station
2007	MLE	230 kV Mount Lehman Substation
2009	BMT	230 kV Bear Mountain Terminal Station

In-Service Year	Station Code	Station Description
2009	UHT	360 kV Upper Harrison Terminal Station
2010	DKT	230 kV Dokie Terminal Station
2010	HWW	230 kV Harewood West Substation
2012	KHS	230 kV Kicking Horse Substation
2013	SYA	500 kV Seymour Arm Capacitor Station
2014	BQN	287 kV Bob Quinn Substation
2014	TAT	287 kV Tatogga Substation
2014	MPT	230 kV Mount Pleasant Substation
2015	SGB	230 kV Shell Groundbirch Switching Station
2015	SLS	230 kV Sundance Lake Substation
2015	RYC	500 kV Ruby Creek Capacitor Station
2016	FLW	230 kV Fleetwood Substation
2016	MKT	230 kV Meikle Terminal Station

Transmission Capacity of the BC Hydro Transmission System

From a customer service perspective, the transmission system is typically designed to reliably serve the forecasted system peak load demand while meeting performance requirements in terms of transmission planning reliability standards. While it is possible to determine the transfer capacity of a specific transmission reinforcement project, it is not feasible to quantify the overall transmission capacity of an integrated transmission system that serves both geographically spread-out generation resources and system loads. However, transmission system capacity can be implicitly reflected by the changes in actual peak load served reliably over a period of time by that transmission system while at the same time meeting the performance requirements.

The BC Hydro transmission system served an integrated system peak load of 8,243 megawatts in 1998 compared to 10,045 megawatts in 2019. On January 13, 2020 the integrated system peak load served reached an all-time high of 10,302 megawatts.

Another indicator that could reflect the changes in transmission capacity over time is the number of customers reliably served by the system. The BC Hydro transmission system facilitated service to a total of 1.53 million customer accounts in 1998 and this increased to 2.05 million customer accounts by 2019. Among them, the number of customers served at transmission voltages increased from 91 to 195 over the same period.

The industry accepted reliability measurement Transmission – System Average Interruption Frequency Index (T-SAIFI) is another indicator that reflects the change in transmission system capacity. T-SAIFI is the average number of interruptions that a delivery point[1] experienced during a given period (e.g., one year in general). Statistical analysis indicates that BC Hydro's T-SAIFI has been reduced from 1.95 in 1998 to 1.20 in 2019 and T-SAIDI has averaged 1.44 over the past five years (2015 to 2019). This reduction in T-SAIFI indicates improving reliability due to fewer transmission outages in recent years.

[1] **For T-SAIDI and T-SAIFI, a delivery point is defined as the point where the energy from transmission system is transferred to the distribution system or to the transmission voltage customer.**

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
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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."

2.8.7 Please explain the intent and purpose behind the harmonization tariff.

RESPONSE:

As described in Recital of Commission Order No. G-12-99, "The objective of harmonization is to eliminate rate stacking or "pancaking" - that is, the payment by customers of two transmission wheeling tariffs on transactions where power is moved between utility service areas". "Wheeling tariffs" refers to Point-To-Point Transmission Service tariffs similar to that provided under Part II of BC Hydro's OATT.

With respect to BC Hydro's OATT, rate harmonization is only available between the service areas of BC Hydro and FortisBC Inc. Specifically, it is available where Point-To-Point Transmission Services is required from both BC Hydro and FortisBC Inc. in order to transfer energy from a point in BC Hydro's service area to a load located in FortisBC Inc.'s area (i.e., non-network load). Although the customer must reserve Point-To-Point Transmission Service on both sides of the Point of Interconnection, it is only charged for this service on the FortisBC system and the rate charged on BC Hydro's system is zero per OATT Rate Schedule 01. The Transmission Customer must, however, pay for applicable Ancillary Services on both Systems. FortisBC Inc. has reciprocal provisions in its tariff relating to transfers into BC Hydro's system.

The intent of Rate Harmonization is to allow generators on either the BC Hydro or FortisBC Inc. system to reach potential customers on either the BC Hydro or FortisBC Inc. system in an economically comparable manner. As noted in the original rate harmonization decision, so long as the opportunities were roughly symmetric, then ratepayers of both FortisBC Inc. and BC Hydro would be roughly neutral with respect to cost shifting.

The Note to Table 2 on page five of BC Hydro's Posting of Transmission Service Offerings business practice provided as Attachment 3 to BC Hydro's response to BCUC IR 1.163.1 provides further information regarding how BC Hydro implements the rate harmonization provision contained in the OATT.

8.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

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2.8.8 Please explain the difference between the OATT and the harmonization tariff.

RESPONSE:

The Open Access Transmission Tariff (OATT) defines all terms and conditions for the provision of transmission service on BC Hydro's transmission system, and it includes the rate harmonization provision referred to as the harmonization tariff. Specifically, the rate harmonization provision is included in the OATT Rate Schedule 01 (Point-To-Point Transmission Service).

For further discussion with regards to how the rate harmonization provision is applied, please refer to BC Hydro's response to BCUC Panel IR 2.8.7.

9.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-12, BCUC IR 266.2, 266.2.1 266.2.2, 266.5;
Exhibit B-19, Appendix A, Schedule 3.4
Point-to-Point Transmission Service

Responses to BCUC IRs 266.2 and 266.2.1 identify that there are 22 external OATT customers that have executed Point-to-Point (PTP) Umbrella Agreements to use BC Hydro’s PTP transmission service.

2.9.1 How many of the 22 external OATT customers with Umbrella Agreements are for short-term (ST) PTP transmission service, and how many are for Long-Term (LT) PTP transmission service?

RESPONSE:

All of the 22 external Customer Umbrella Agreements are for Short-Term Point-To-Point Transmission Service.

Per Attachment A of the OATT, Umbrella Agreements are only for Short-Term Firm or Non-Firm Point-To-Point Transmission Service. OATT customers receiving Long-Term Firm Point-To-Point Transmission Service are required to have a Service Agreement per Attachment B of the OATT and cannot receive Long-Term Firm Point-To-Point transmission service under an Umbrella Agreement. OATT customers can have both Umbrella Agreements and Service Agreements, and currently three customers have both types of Agreement in place.

9.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-12, BCUC IR 266.2, 266.2.1 266.2.2, 266.5;
Exhibit B-19, Appendix A, Schedule 3.4
Point-to-Point Transmission Service

BCUC IR 266.2.2 provides the table below that reflects the location of customers that use BC Hydro's PTP transmission service, excluding BC Hydro and Powerex:

Location	Number of OATT Customers
Within BC Hydro's service area	0
Outside of BC Hydro's service area, but within B.C.	1
Outside of BC Hydro's service area and outside of B.C.	21

2.9.2 Please discuss where (i.e. province / state) outside BC Hydro's service area these external OATT customers are based.

RESPONSE:

The external OATT customers listed in the table included in BC Hydro's response to BCUC IR 2.266.2.2 are based in British Columbia, Alberta, Saskatchewan, Quebec, Washington, Texas, Pennsylvania, New York, and North Dakota.

9.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-12, BCUC IR 266.2, 266.2.1 266.2.2, 266.5;
Exhibit B-19, Appendix A, Schedule 3.4
Point-to-Point Transmission Service

BC Hydro's response to BCUC IR 266.5 provides the below table and states the following:

Fiscal Year	Number of Umbrella Agreements from New Customers	Number of Signed Service Agreements from New Customers	Number of Signed Service Agreements from Existing Customers
F2017	0	0	3
F2018	1	0	2
F2019	0	0	4

2.9.3 Please confirm, or otherwise explain, that there are zero IPPs within BC Hydro's service area that are also OATT customers.

RESPONSE:

Confirmed. There are no IPPs that currently have an OATT Attachment A, Umbrella Agreement for Short-Term Firm or Non-Firm Point-To-Point Transmission Service or an OATT Attachment B, Service Agreement for Long-Term Firm Point-To-Point Transmission Service with BC Hydro. However, an IPP does not require either type of agreement in its own name in order to facilitate an export of electricity. An IPP could contract with an entity that is a Transmission Customer, such as a power marketer, to act on its behalf and facilitate an export of the electricity.

9.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

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Exhibit B-12, BCUC IR 266.2, 266.2.1 266.2.2, 266.5;
Exhibit B-19, Appendix A, Schedule 3.4
Point-to-Point Transmission Service

BC Hydro's response to BCUC IR 266.5 provides the below table and states the following:

Fiscal Year	Number of Umbrella Agreements from New Customers	Number of Signed Service Agreements from New Customers	Number of Signed Service Agreements from Existing Customers
F2017	0	0	3
F2018	1	0	2
F2019	0	0	4

2.9.3 Please confirm, or otherwise explain, that there are zero IPPs within BC Hydro's service area that are also OATT customers.

2.9.3.1 If confirmed, please clarify how IPP generation could be exported to the US or Alberta by either of BC Hydro or Powerex. In your response, please identify who pays for PTP transmission used in exporting electricity from the IPP.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.163.1 which includes a description of how an eligible customer can become a transmission customer and use BC Hydro's Transmission System to export electricity. The eligible customer could be an IPP or an entity contracted by the IPP to act on its behalf, such as a power marketer.

IPP generation could be exported by Powerex or any other power marketer, if the IPP contracted with Powerex or any other entity to act as its power marketer. Any power marketer that is an eligible transmission customer could procure PTP Transmission Service under the OATT to schedule IPP energy for export.

BC Hydro does not export power to jurisdictions outside of B.C. BC Hydro transacts with Powerex who engages in import and export activity with other jurisdictions.

In all cases, the charges for PTP Transmission Service used to export electricity, as well as any ancillary services that are attracted by the reservation, would be paid by the Transmission Customer that purchases the Transmission reservation.

9.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-12, BCUC IR 266.2, 266.2.1 266.2.2, 266.5;
Exhibit B-19, Appendix A, Schedule 3.4
Point-to-Point Transmission Service

BC Hydro's response to BCUC IR 266.5 provides the below table and states the following:

Fiscal Year	Number of Umbrella Agreements from New Customers	Number of Signed Service Agreements from New Customers	Number of Signed Service Agreements from Existing Customers
F2017	0	0	3
F2018	1	0	2
F2019	0	0	4

2.9.4 Please clarify how many of the nine Service Agreements with existing customers signed since 2019 are with internal customers (BC Hydro and Powerex), and how many are with external OATT customers.

RESPONSE:

Out of the nine Service Agreements executed between fiscal 2017 to fiscal 2019, eight are with internal customers and one is with an external OATT customer.

9.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-12, BCUC IR 266.2, 266.2.1 266.2.2, 266.5;
Exhibit B-19, Appendix A, Schedule 3.4
Point-to-Point Transmission Service

Schedule 3.4 of Appendix A to the Evidentiary Update shows forecast LT PTP Volumes for both Internal and External customers.

	Reference	F2019			F2020			F2021		
		RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
Long-Term PTP Volumes (GWh)										
Internal		8,042	8,609	568	8,567	8,567	0	8,567	8,567	0
External		1,314	876	(438)	1,314	1,314	0	1,314	1,314	0
Total		9,356	9,485	130	9,881	9,881	0	9,881	9,881	0

2.9.5 Please confirm, or otherwise explain, that forecast LT PTP Volumes with external customers during the F2020 and F2021 test periods reflect the four new Service Agreements for LT PTP transmission service signed by existing Transmission Customers in F2019.

RESPONSE:

Confirmed. Forecast Long-Term Point-To-Point Volumes comprise all known service agreements and any expected changes in service agreements during the test period.

9.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-12, BCUC IR 266.2, 266.2.1 266.2.2, 266.5;
Exhibit B-19, Appendix A, Schedule 3.4
Point-to-Point Transmission Service

Schedule 3.4 of Appendix A to the Evidentiary Update shows forecast LT PTP Volumes for both Internal and External customers.

		F2019			F2020			F2021		
	Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
Long-Term PTP Volumes (GWh)										
Internal		8,042	8,609	568	8,567	8,567	0	8,567	8,567	0
External		1,314	876	(438)	1,314	1,314	0	1,314	1,314	0
Total		9,356	9,485	130	9,881	9,881	0	9,881	9,881	0

2.9.6 Please discuss whether capacity constraints on BC Hydro's transmission system are a consideration for the provision of LT PTP transmission service.

RESPONSE:

Yes. Long-Term Point-To-Point Transmission Service is based on Long-Term Available Transfer Capability (ATC) on the transmission path requested through a Transmission Service Request. The Long-Term ATC is determined through System Impact Studies, which include consideration of transmission system capacity constraints.

9.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-12, BCUC IR 266.2, 266.2.1 266.2.2, 266.5;
Exhibit B-19, Appendix A, Schedule 3.4
Point-to-Point Transmission Service

Schedule 3.4 of Appendix A to the Evidentiary Update shows forecast LT PTP Volumes for both Internal and External customers.

		F2019			F2020			F2021		
	Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
Long-Term PTP Volumes (GWh)										
Internal		8,042	8,609	568	8,567	8,567	0	8,567	8,567	0
External		1,314	876	(438)	1,314	1,314	0	1,314	1,314	0
Total		9,356	9,485	130	9,881	9,881	0	9,881	9,881	0

2.9.7 Please identify the most recent year in which a new entity that applied to become a BC Hydro transmission customer executed a Service Agreement for LT PTP transmission service.

RESPONSE:

2007 was the most recent year in which a new entity became an eligible BC Hydro transmission customer and executed a Long-Term Point-To-Point Service Agreement.

9.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-12, BCUC IR 266.2, 266.2.1 266.2.2, 266.5;
Exhibit B-19, Appendix A, Schedule 3.4
Point-to-Point Transmission Service

Schedule 3.4 of Appendix A to the Evidentiary Update shows forecast LT PTP Volumes for both Internal and External customers.

	Reference	F2019			F2020			F2021		
		RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
Long-Term PTP Volumes (GWh)										
Internal		8,042	8,609	568	8,567	8,567	0	8,567	8,567	0
External		1,314	876	(438)	1,314	1,314	0	1,314	1,314	0
Total		9,356	9,485	130	9,881	9,881	0	9,881	9,881	0

2.9.8 Please identify the most recent year in which BC Hydro exercised its right to rollover its service for LT PTP transmission.

RESPONSE:

In 2019, BC Hydro exercised its right to rollover its Long-Term Point-To-Point Transmission Service.

9.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-12, BCUC IR 266.2, 266.2.1 266.2.2, 266.5;
Exhibit B-19, Appendix A, Schedule 3.4
Point-to-Point Transmission Service

Schedule 3.4 of Appendix A to the Evidentiary Update shows forecast LT PTP Volumes for both Internal and External customers.

		F2019			F2020			F2021		
	Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
Long-Term PTP Volumes (GWh)										
Internal		8,042	8,609	568	8,567	8,567	0	8,567	8,567	0
External		1,314	876	(438)	1,314	1,314	0	1,314	1,314	0
Total		9,356	9,485	130	9,881	9,881	0	9,881	9,881	0

2.9.9 Please discuss if a Service Agreement identifies the type of LT PTP transmission service(s) to be accommodated (i.e. firm or conditional firm service).

RESPONSE:

Yes. A Service Agreement, OATT Attachment B, is offered to a customer who receives firm or conditional firm service. The amount of firm or conditional firm transmission capacity will be specified on the Specifications for Long-Term Firm Point-To-Point Transmission Service, which is an appendix to Attachment B.

9.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-12, BCUC IR 266.2, 266.2.1 266.2.2, 266.5;
Exhibit B-19, Appendix A, Schedule 3.4
Point-to-Point Transmission Service

Schedule 3.4 of Appendix A to the Evidentiary Update shows forecast LT PTP Volumes for both Internal and External customers.

		F2019			F2020			F2021		
	Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
Long-Term PTP Volumes (GWh)										
Internal		8,042	8,609	568	8,567	8,567	0	8,567	8,567	0
External		1,314	876	(438)	1,314	1,314	0	1,314	1,314	0
Total		9,356	9,485	130	9,881	9,881	0	9,881	9,881	0

2.9.9 Please discuss if a Service Agreement identifies the type of LT PTP transmission service(s) to be accommodated (i.e. firm or conditional firm service).

2.9.9.1 Please discuss how many of the nine signed Service Agreements from existing customers between F2017 and F2019 were for firm PTP transmission service or Conditional Firm Service.

RESPONSE:

Out of the nine signed Service Agreements, four were for Firm Point-To-Point Transmission Service and five were for Conditional Firm Service.

10.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-5, BCUC IR 165.1, 168.1; Exhibit B-13, AMPC IR 46.3, Attachment 1, p. 19; Exhibit B-19, Appendix A, Schedule 3.4
PTP Transmission Service – Internal Customers

BC Hydro’s response to BCUC IR 165.1 states:

> BC Hydro allocates a portion of its Point-To-Point costs to Powerex consistent with the Transfer Pricing Agreement. This allocation is performed monthly and does not separate Long-Term Point-To-Point charges from Short-Term Point-To-Point charges. The total monthly Point-To-Point costs are allocated based on each entity’s activity within the month. Specifically, BC Hydro is the transmission customer under the OATT and reserves all Point-To-Point transmission required on its transmission system to meet its requirements.

BC Hydro’s response to BCUC IR 168.1 states:

> BC Hydro is the entity that reserves both the Network Integration and the Point-To-Point transmission services as the customer under the OATT. BC Hydro, as customer, is then charged for these services, plus other required services such as scheduling and dispatch services, by BC Hydro as Transmission Provider, just as any other customer is charged for these services under the OATT.

2.10.1 Please clarify that BC Hydro, as a transmission customer, holds service agreements with BC Hydro in the same manner that external OATT customers hold service agreements for PTP transmission service.

RESPONSE:

Confirmed. BC Hydro, as a Transmission Customer, is governed by the provisions of the OATT and holds service agreements in the same manner that external OATT customers hold service agreements for Point-To-Point Transmission Service.

10.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-5, BCUC IR 165.1, 168.1; Exhibit B-13, AMPC IR 46.3, Attachment 1, p. 19; Exhibit B-19, Appendix A, Schedule 3.4
PTP Transmission Service – Internal Customers

Page 19 of Attachment 1 of BC Hydro's response to Association of Major Power Customers of British Columbia (AMPC) IR 46.3 states:

> B.C. Hydro shall pay for all transmission charges and shall self-supply all losses and ancillary services charges, on the Transmission System for electricity transactions under this Agreement [Transfer Pricing Agreement]. Unless otherwise determined by B.C. Hydro, acting reasonably, Powerex will pay to B.C. Hydro an amount equal to the parties' reasonable estimate of:
>
> - 9.2.1. the point-to-point transmission costs incurred by B.C. Hydro presently under Rate Schedule 3000 and 3001 in respect of transactions under this Agreement other than sales by B.C. Hydro to Powerex of Surplus Hydro Electricity under Section 5 .1, excluding
> - 9.2.2. the point-to-point transmission costs incurred by B.C. Hydro in respect of transactions under any Interutility Agreements, to fulfill any of B.C. Hydro's treaty obligations and transactions in respect of the Canadian Entitlement,

Line 18 of Schedule 3.4 of Appendix A to the Evidentiary Update reflects Powerex PTP charges in each of fiscal 2020 and fiscal 2021 to be $41.5M and $34.0M, respectively.

2.10.2 Please explain any differences between the OATT and the Transfer Pricing Agreement, as they relate to energy, capacity, wheeling and other OATT related charges.

RESPONSE:

The Open Access Transmission Tariff (OATT) and the Transfer Pricing Agreement (TPA) serve two different purposes. The OATT allows for parties, including BC Hydro, to reserve transmission capacity on BC Hydro's transmission system for the purpose of separately transmitting energy. The TPA is an enabling agreement that governs the terms under which energy is transferred between BC Hydro and Powerex, including the allocation of transmission costs that may be incurred in transmitting energy under the TPA.

Please refer to BC Hydro's response to BCUC Panel IR 2.10.3 for more details on the allocation of transmission charges under the TPA.

10.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-5, BCUC IR 165.1, 168.1; Exhibit B-13, AMPC IR 46.3, Attachment 1, p. 19; Exhibit B-19, Appendix A, Schedule 3.4
PTP Transmission Service – Internal Customers

Page 19 of Attachment 1 of BC Hydro's response to Association of Major Power Customers of British Columbia (AMPC) IR 46.3 states:

> B.C. Hydro shall pay for all transmission charges and shall self-supply all losses and ancillary services charges, on the Transmission System for electricity transactions under this Agreement [Transfer Pricing Agreement]. Unless otherwise determined by B.C. Hydro, acting reasonably, Powerex will pay to B.C. Hydro an amount equal to the parties' reasonable estimate of:
>
> - 9.2.1. the point-to-point transmission costs incurred by B.C. Hydro presently under Rate Schedule 3000 and 3001 in respect of transactions under this Agreement other than sales by B.C. Hydro to Powerex of Surplus Hydro Electricity under Section 5 .1, excluding
> - 9.2.2. the point-to-point transmission costs incurred by B.C. Hydro in respect of transactions under any Interutility Agreements, to fulfill any of B.C. Hydro's treaty obligations and transactions in respect of the Canadian Entitlement,

Line 18 of Schedule 3.4 of Appendix A to the Evidentiary Update reflects Powerex PTP charges in each of fiscal 2020 and fiscal 2021 to be $41.5M and $34.0M, respectively.

2.10.3 Please explain the process for how PTP transmission service is allocated by BC Hydro to Powerex under the TPA. As part of your response, please elaborate on how PTP transmission used to export electricity from each of an IPP or from BC Hydro's generation resources could be identified.

RESPONSE:

BC Hydro allocates to Powerex a portion of its annual PTP charges to reflect the portion of charges associated with imports and exports under the TPA for trade purposes. All remaining PTP charges not allocated to Powerex are incurred by BC Hydro, reflecting (i) BC Hydro sales to Powerex of surplus hydroelectricity; (ii) transactions under BC Hydro's inter-utility agreements; and (iii) transactions pursuant to BC Hydro's Skagit Valley Treaty obligations and Columbia River

Treaty obligations (i.e., Canadian Entitlement transactions between BC Hydro and Powerex).

In addition to Transmission Service for TPA activity, Powerex may also, from time to time, transact electricity directly with third-parties in British Columbia outside of the TPA and may reserve Point-to-Point wholesale transmission service in its own right to support the transmission of electricity in B.C. associated with those transactions. Powerex may also, from time to time, reserve in its own right Point-to-Point transmission service between the B.C.-A.B. border and the B.C.-U.S. border (wheelthrough service). In such circumstances, Powerex is the transmission customer that directly incurs the wholesale transmission service charges for PTP Transmission Services for its own account. BC Hydro is not a party involved in such transactions and, accordingly, these transactions are not included in the TPA allocation process.

With respect to PTP transmission service used for export, under the TPA BC Hydro makes Surplus Energy and Surplus System Capability available to Powerex to export from its aggregated system of resources (which may include BC Hydro purchases of IPP supply under Electricity Purchase Agreements). The PTP transmission reservation itself does not indicate a specific generation resource. BC Hydro uses transmission reservations at generic points on the transmission system for export purposes. The delivery points for the export transmission may either be the B.C.-U.S. border, the B.C.-A.B. border or the Kootenay Interconnection (for transfers to FortisBC Inc.). Generally for exports there is no ability to distinguish IPP generation and BC Hydro generation since the source generation is based on the aggregate system capability. In limited instances, such as when wind output is sold in the export market as a renewable energy product, specific BC IPP generation resources may be registered with the North American Energy Standards Board Electric Industry Registry as a Source so that the specific IPP resource can be identified in the applicable energy schedule.

10.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-5, BCUC IR 165.1, 168.1; Exhibit B-13, AMPC IR 46.3, Attachment 1, p. 19; Exhibit B-19, Appendix A, Schedule 3.4
PTP Transmission Service – Internal Customers

Page 19 of Attachment 1 of BC Hydro's response to Association of Major Power Customers of British Columbia (AMPC) IR 46.3 states:

> B.C. Hydro shall pay for all transmission charges and shall self-supply all losses and ancillary services charges, on the Transmission System for electricity transactions under this Agreement [Transfer Pricing Agreement]. Unless otherwise determined by B.C. Hydro, acting reasonably, Powerex will pay to B.C. Hydro an amount equal to the parties' reasonable estimate of:
>
> - 9.2.1. the point-to-point transmission costs incurred by B.C. Hydro presently under Rate Schedule 3000 and 3001 in respect of transactions under this Agreement other than sales by B.C. Hydro to Powerex of Surplus Hydro Electricity under Section 5 .1, excluding
> - 9.2.2. the point-to-point transmission costs incurred by B.C. Hydro in respect of transactions under any Interutility Agreements, to fulfill any of B.C. Hydro's treaty obligations and transactions in respect of the Canadian Entitlement,

Line 18 of Schedule 3.4 of Appendix A to the Evidentiary Update reflects Powerex PTP charges in each of fiscal 2020 and fiscal 2021 to be $41.5M and $34.0M, respectively.

2.10.4 Please clarify whether Powerex holds any service agreements with BC Hydro in the same manner that external OATT customers hold service agreements for PTP transmission service. As part of your response, please identify the total PTP transmission capacity associated with those service agreements held by Powerex.

RESPONSE:

No, Powerex does not presently hold any service agreements with BC Hydro under the OATT and therefore zero megawatts of transmission capacity are reserved by Powerex using service agreements. Powerex does hold an umbrella agreement for short-term transmission service with BC Hydro under the OATT in the same manner that external OATT customers hold umbrella agreements for Point-To-Point Transmission Service. However, volumes of transmission service procured under this umbrella agreement are short-term and variable in nature.

10.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-5, BCUC IR 165.1, 168.1; Exhibit B-13, AMPC IR 46.3, Attachment 1, p. 19; Exhibit B-19, Appendix A, Schedule 3.4
PTP Transmission Service – Internal Customers

Page 19 of Attachment 1 of BC Hydro's response to Association of Major Power Customers of British Columbia (AMPC) IR 46.3 states:

> B.C. Hydro shall pay for all transmission charges and shall self-supply all losses and ancillary services charges, on the Transmission System for electricity transactions under this Agreement [Transfer Pricing Agreement]. Unless otherwise determined by B.C. Hydro, acting reasonably, Powerex will pay to B.C. Hydro an amount equal to the parties' reasonable estimate of:
>
> - 9.2.1. the point-to-point transmission costs incurred by B.C. Hydro presently under Rate Schedule 3000 and 3001 in respect of transactions under this Agreement other than sales by B.C. Hydro to Powerex of Surplus Hydro Electricity under Section 5 .1, excluding
> - 9.2.2. the point-to-point transmission costs incurred by B.C. Hydro in respect of transactions under any Interutility Agreements, to fulfill any of B.C. Hydro's treaty obligations and transactions in respect of the Canadian Entitlement,

Line 18 of Schedule 3.4 of Appendix A to the Evidentiary Update reflects Powerex PTP charges in each of fiscal 2020 and fiscal 2021 to be $41.5M and $34.0M, respectively.

2.10.4 Please clarify whether Powerex holds any service agreements with BC Hydro in the same manner that external OATT customers hold service agreements for PTP transmission service. As part of your response, please identify the total PTP transmission capacity associated with those service agreements held by Powerex.

2.10.4.1 If confirmed, please discuss whether any of the OATT service agreements Powerex holds are outside the transmission charges payable to BC Hydro through the Transfer Pricing Agreement, as described in the preamble.

RESPONSE:

Please refer to BC Hydro's response to BCUC Panel IR 2.10.4 in which BC Hydro stated that Powerex does not currently hold any service agreements with BC Hydro under the OATT.

If Powerex did hold a Service Agreement under the OATT, any charges associated with this transmission service would be charged directly to Powerex in accordance with the OATT and not included in the TPA allocation.

11.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, pp. 4-23, 4-39; Exhibit B-12, BCUC IR 234.1; Exhibit B-19, Appendix A, Schedule 3.4, Schedule 4.0, Schedule 15.0
BC Hydro F2017 to F2019 Revenue Requirements Application (F2017-F2019 RRA), Exhibit B-14, BCUC IR 308.2
Internal and External OATT revenues

BC Hydro's response to BCUC IR 234.1 states:

> The table below lists the items that are not eligible for deferral to regulatory accounts:

Forecast Item	Appendix A Reference
Miscellaneous Revenues	Schedule 15.0, line 42 less lines 4 and 9
Operating costs	Schedule 5.0, line 15[(1)]
Provision and Other Costs	Schedule 5.0, lines 65 to 71[(2)]
Amortization (DSM and Existing Capital Assets) – Excludes Amortization on Capital Additions during the Test Period	Schedule 7.0, line 32 Less: Schedule 7.0, line 28 Schedule 7.0, line 30 Schedule 13.0, line 35
First Nations Negotiations Costs	Schedule 5.0, line 54[(3)]
Taxes	Schedule 6.0, line 24
Asset Retirement Obligation Accretion	Schedule 8.0, line 16
Powertech Net Income	Schedule 1.0, line 18

1. Except for the variances between forecast and actual Storm Restoration Costs and Current Service Costs.
2. Lines 65 to 71 include asset retirements and gains/losses on asset disposals.

Line 4 in Schedule 15.0 of Appendix A to the Evidentiary Update reflects External OATT revenues, which are included in the TRR.

			F2019			F2020			F2021		
		Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
	Transmission										
4	External OATT	3.4 L73	14.0	15.4	1.4	15.4	15.9	0.5	15.4	15.9	0.5
5	FortisBC Wheeling Agreement		5.0	5.2	0.2	5.2	5.2	0.0	5.3	5.3	0.0
6	Secondary Revenue		5.0	8.7	3.6	6.0	6.0	0.0	6.2	6.2	0.0
7	Interconnections		1.9	4.9	3.0	2.2	2.2	0.0	2.2	2.2	0.0
8	Amortization of Contributions	11.0 L18:L19-L14	14.4	21.1	6.8	14.8	14.6	(0.3)	15.3	15.0	(0.3)
9	NTL Supplemental Charge		2.0	2.3	0.2	2.3	2.3	0.0	2.3	2.3	0.0
10	Total		42.4	57.6	15.3	45.9	46.1	0.2	46.6	46.8	0.2

2.11.1 Please explain why revenues from external OATT customers are eligible for deferral treatment. In your response, please explain the effect these variances have on both short-term (i.e. the next TRR) and long-term (i.e. beyond the next TRR) rates as paid by external OATT customers.

RESPONSE:

When BCTC was integrated with BC Hydro in fiscal 2011, BC Hydro sought approval to continue to defer variances between the forecast and actual transmission services revenues, including external OATT revenues, to the Non-Heritage Deferral Account. They were previously captured in the BCTC Deferral Account before its termination upon BCTC's integration into BC Hydro. The Commission approved BC Hydro's request in BCUC Order No. G-16-11.

Accordingly, external OATT revenue variances are deferred to the Non-Heritage Deferral Account (NHDA) and since the amortization of NHDA balance falls under "Customer Care" (and not Transmission), these variances have no impact, either in the short-term or long-term, on Transmission Revenue Requirement (TRR) rates.

11.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, pp. 4-23, 4-39; Exhibit B-12, BCUC IR 234.1; Exhibit B-19, Appendix A, Schedule 3.4, Schedule 4.0, Schedule 15.0
BC Hydro F2017 to F2019 Revenue Requirements Application (F2017-F2019 RRA), Exhibit B-14, BCUC IR 308.2
Internal and External OATT revenues

BC Hydro's response to BCUC IR 308.2 in the F2017-F2019 RRA states that:

> Variances between forecast and actual Point-to-Point charges (inter-segment revenues) are deferred to the Non-Heritage Deferral Account. Inter-segment revenues include charges to Powerex for Point-to-Point and charges to BC Hydro for BC Hydro's obligations under the Skagit Valley Treaty as well as charges associated with surplus sales.
>
> BC Hydro records the related costs for Point-to-Point charges in Heritage cost of energy (Appendix A, Schedule 4.0, line 30). Variances between forecast and actual amounts are deferred to the Heritage Deferral Account.

2.11.2 Please confirm that variances between forecast and actual PTP transmission allocated to the Cost of Heritage Energy are captured in the Heritage Deferral Account.

RESPONSE:

Confirmed.

11.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, pp. 4-23, 4-39; Exhibit B-12, BCUC IR 234.1; Exhibit B-19, Appendix A, Schedule 3.4, Schedule 4.0, Schedule 15.0
BC Hydro F2017 to F2019 Revenue Requirements Application (F2017-F2019 RRA), Exhibit B-14, BCUC IR 308.2
Internal and External OATT revenues

Page 4-23 of the Application states "The costs included under Domestic Transmission – Other…include approximately $16 million per year for wholesale transmission in British Columbia, to deliver energy to the B.C./US. Border."

Page 4-39 of the Application states the following:

- The use of BC Hydro's transmission system for export related to Surplus Sales pursuant to the OATT is referred to as Domestic Transmission – Export.
- Domestic Transmission – Export costs are expected to be $17.4 million in fiscal 2020 and $21.0 in fiscal 2021.

2.11.3 Please confirm that variances between forecast and actual PTP transmission used for exporting surplus sales are captured in the Non-Heritage Deferral Account.

RESPONSE:

Not confirmed. Point-To-Point (PTP) transmission costs used for surplus sales are shown as Domestic Transmission – Export on line 37, Schedule 4.0 of Appendix A of the Evidentiary Update as part of Market Energy. Variances between forecast and actual PTP transmission costs used for surplus sales are deferred to the Heritage Deferral Account as shown on line 60, Schedule 4.0 of Appendix A of the Evidentiary Update.

11.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, pp. 4-23, 4-39; Exhibit B-12, BCUC IR 234.1; Exhibit B-19, Appendix A, Schedule 3.4, Schedule 4.0, Schedule 15.0
BC Hydro F2017 to F2019 Revenue Requirements Application (F2017-F2019 RRA), Exhibit B-14, BCUC IR 308.2
Internal and External OATT revenues

Schedule 3.4 of Appendix A to the Evidentiary Update reflects the following Inter-segment revenues for PTP transmission allocated between BC Hydro and Powerex:

			F2019			F2020			F2021		
		Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
	Inter-Segment Revenue										
18	Powerex PTP Charges		(16.6)	(26.4)	(9.8)	(32.5)	(41.5)	(9.0)	(32.5)	(34.0)	(1.5)
19	BC Hydro PTP Charges		(45.9)	(34.3)	11.6	(33.6)	(19.1)	14.5	(37.2)	(35.0)	2.2
20	Total		(62.5)	(60.7)	1.8	(66.1)	(60.6)	5.5	(69.7)	(69.0)	0.7
21	**Total Current Costs**		828.3	824.5	(3.8)	931.9	971.6	39.7	930.3	969.0	38.7

Schedule 4.0 of Appendix A to the Evidentiary Update reflects the following allocations of PTP transmission to the Cost of Energy:

		F2019			F2020			F2021		
		RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Line	Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
	Cost of Energy ($ million)									
	Heritage Energy									
23	Water Rentals	356.4	363.1	6.7	343.1	329.3	(13.8)	349.1	323.2	(25.9)
24	Natural Gas for Thermal Generation	10.7	7.6	(3.1)	8.1	7.5	(0.6)	8.5	8.5	(0.0)
25	Domestic Transmission - Other	22.1	22.3	0.2	22.5	24.5	2.0	22.4	24.4	2.0
26	Non-Treaty Storage and Libby Coordination Ag	(7.2)	(181.9)	(174.7)	3.3	15.0	11.7	(2.5)	(11.7)	(9.3)
27	Remissions and Other	(33.1)	(33.9)	(0.8)	(26.1)	(25.2)	0.9	(26.8)	(26.7)	0.1
28	Total	349.0	177.2	(171.8)	350.9	351.2	0.3	350.8	317.7	(33.1)
	Market Energy									
34	Market Electricity Purchases	35.9	125.0	89.1	40.0	211.6	171.5	18.2	43.7	25.4
35	Surplus Sales	(129.2)	(115.0)	14.2	(97.1)	(0.4)	96.7	(111.4)	(97.0)	14.4
36	Net Purchases (Sales) from Powerex	0.7	25.0	24.3	(0.5)	33.1	33.6	0.5	6.1	5.6
37	Domestic Transmission - Export	29.9	18.5	(11.4)	17.4	1.1	(16.3)	21.0	17.0	(4.0)
38	Total	(62.6)	53.5	116.1	(40.2)	245.3	285.5	(71.7)	(30.3)	41.4

2.11.4 Please explain why BC Hydro PTP charges in Line 19 of Schedule 3.4 do not reconcile to allocations of domestic transmission as reflected in Schedule 4.0, and as provided in the Evidentiary Update and summarized in the below BCUC staff table:

(in $ million)	F2020		F2021	
	Plan	Update	Plan	Update
Schedule 3.4				
BC Hydro PTP Charges (Line 19)	$33.6	$19.1	$37.2	$35.0
Schedule 4.0				
Domestic Transmission – Other* (Line 25)	$16.0	$16.0	$16.0	$16.0
Domestic Transmission – Export (Line 37)	$17.4	$1.1	$21.0	$17.0
Total	$33.4	$17.1	$37.0	$33.0
Difference	$0.2	$2.0	$0.2	$2.0

**~$16.0 million is described in the preamble as wholesale transmission in B.C. to deliver energy to the B.C. U.S. border, and comprises part of the total reflected in Line 25 of Schedule 4.0.*

RESPONSE:

BC Hydro PTP charges on line 19 of Schedule 3.4 of Appendix A do reconcile with the domestic transmission costs shown in Schedule 4.0 of Appendix A. This is shown in the table below.

The difference between the table below and the BCUC staff table in the preamble to the question is the portion of Point-To-Point charges included in Domestic Transmission – Other total provided on line 25 of Schedule 4.0 of Appendix A.

On page 4-23 of Chapter 4 of Appendix A, BC Hydro states that the portion of Point-To-Point charges included in Domestic Transmission – Other is “approximately $16 million”. This approximate value is the one used in the BCUC staff table. In the table below, BC Hydro provides the actual values from the Application and the Evidentiary Update.

	($ Million)	Appendix A Reference	F2020 Plan	F2020 Update	F2021 Plan	F2021 Update
	Schedule 3.4					
1	BC Hydro PTP Charges	3.4L19	33.6	19.1	37.2	35.0
	Schedule 4.0					
2	Domestic Transmission - Other[1]		16.2	18.0	16.2	18.0
3	Domestic Transmission - Export	4.0L37	17.4	1.1	21.0	17.0
4	Total	L2+L3	33.6	19.1	37.2	35.0
5	Difference	L1–L4	-	-	-	-

1. Wholesale transmission in B.C. to deliver energy to B.C./U.S. border, and comprises part of the total reflected in line 25 of Schedule 4.0

12.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-5, BCUC IR 163.1, 163.5.1, 164.1, 164.1.1
NITS and PTP Allocation to Distribution

In Exhibit B-5, BC Hydro's response to BCUC IR 163.1 states:

> BC Hydro notes that Network Load in BC Hydro's service area would not be served using PTP but instead is served by BC Hydro as the Network Customer using Network Integration Transmission Service in accordance with Part I (Common Service Provisions) and Part III (Network Integration Transmission Service) of the OATT.

BC Hydro's response to BCUC IR 164.1 states:

> Point-To-Point Allocation to Distribution on Appendix A, schedule 3.4, line 12 represents the cost to use Point-To-Point transmission service to serve domestic load customers. It is a cost borne by BC Hydro domestic load customers and is recovered through BC Hydro's bundled sales rates.

BC Hydro's response to BCUC IR 164.1.1 states:

> …Point-To-Point transmission costs are allocated to domestic load customers as they benefit from the use of the transmission system to move energy from generation facilities to their point of interconnection (e.g. on the distribution system).

2.12.1 Please explain the difference between "Point-to-Point Allocation to Distribution" and Network Integrated Transmission Service as it relates to providing service to domestic load customers.

RESPONSE:

BC Hydro has corrected its response to BCUC IR 164.1 in Exhibit B-5-2 to clarify that the Point-To-Point (PTP) Allocation to Distribution is the PTP costs associated with the re-export of the Canadian Entitlement plus associated scheduling and dispatch fees. While these costs are recovered from domestic load customers, they are not used to serve domestic load directly. Domestic load customers are served under the electric tariff and the required transmission capacity is reserved through the Network Integration Transmission Service (NITS) provisions of the OATT.

Network Integration Transmission Service (NITS) is a type of Transmission Service provided under Part III of the OATT that is only available to serve a NITS Customer's Network Load from designated network generation resources or from non-designated resources that have been nominated under the secondary service provisions of section 28.4 of the OATT. Please refer to the response to BCUC Panel IR 2.12.1.1 for a more detailed description of NITS.

BC Hydro is currently the only NITS Customer. Accordingly, NITS can only be used to serve BC Hydro's domestic load customers. To supply any other customer requires the use of Point-To-Point Transmission Service.

The PTP Allocation to Distribution is the remaining "internal" Point-To-Point charges (Appendix A, Schedule 3.4, line 52 plus line 61) after accounting for Powerex PTP Charges (Appendix A, Schedule 3.4, line 18) and the BC Hydro PTP Charges that support exports (Appendix A, Schedule 3.4, line 19). This is shown in the table below.

($ Million)	Appendix A Reference	F2020 Plan	F2020 Update	F2021 Plan	F2021 Update
Long-Term PTP Revenue	3.4 L52	76.7	79.9	76.7	79.8
Short-Term PTP Revenue	3.4 L61	24.2	24.2	25.2	25.2
Total PTP Revenue - Internal	3.4 L67	100.9	104.2	101.9	105.0
Powerex PTP Charges	3.4 L18	32.5	41.5	32.5	34.0
BC Hydro PTP Charges	3.4 L19	33.6	19.1	37.2	35.0
Total Intersegment Revenue	3.4 L20	66.1	60.6	69.7	69.0
Remaining PTP Charges (to Distribution)	3.4 L12	34.8	43.6	32.2	36.0

12.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-5, BCUC IR 163.1, 163.5.1, 164.1, 164.1.1
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> BC Hydro notes that Network Load in BC Hydro's service area would not be served using PTP but instead is served by BC Hydro as the Network Customer using Network Integration Transmission Service in accordance with Part I (Common Service Provisions) and Part III (Network Integration Transmission Service) of the OATT.

BC Hydro's response to BCUC IR 164.1 states:

> Point-To-Point Allocation to Distribution on Appendix A, schedule 3.4, line 12 represents the cost to use Point-To-Point transmission service to serve domestic load customers. It is a cost borne by BC Hydro domestic load customers and is recovered through BC Hydro's bundled sales rates.

BC Hydro's response to BCUC IR 164.1.1 states:

> …Point-To-Point transmission costs are allocated to domestic load customers as they benefit from the use of the transmission system to move energy from generation facilities to their point of interconnection (e.g. on the distribution system).

2.12.1 Please explain the difference between "Point-to-Point Allocation to Distribution" and Network Integrated Transmission Service as it relates to providing service to domestic load customers.

2.12.1.1 Please provide an example of how Network Integration Transmission Service (NITS) is used to serve domestic load.

RESPONSE:

Network Integration Transmission Service (NITS) is an Open-Access Transmission Tariff (OATT) service designed to allow a customer to use the Transmission System to deliver energy from multiple resources to multiple loads under one transmission contract.

NITS is defined by Part III of the OATT. Section 28.1 of the OATT defines the scope of NITS as follows:

> **Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.**

BC Hydro as Network Customer uses NITS to deliver electricity from its own generating plants and from contracted Independent Power Producers (IPPs) to serve its domestic load, to fulfill its obligations to supply FortisBC under the Power Purchase Agreement (PPA), and to supply other small loads like Port Roberts. BC Hydro as Network Customer defines its NITS capacity requirements by specifying (a) the capacities and locations of its Network Resources (the BC Hydro and IPP generating plants used to supply BC Hydro's domestic load); and (b) the locations and magnitudes of its forecasted BC Hydro domestic loads and other load obligations (like the PPA).

As described in section 28.3 of the OATT, BC Hydro as Transmission Provider is obligated to provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from the Network Customer's designated Network Resources to service its Network Loads. Further, as described in section 28.2 of the OATT, BC Hydro as Transmission Provider is obligated to plan, construct, operate and maintain its Transmission System to provide the Network Customer with NITS over the Transmission System.

BC Hydro as Network Customer can also nominate energy from secondary sources under section 28.4 of the OATT, which is commonly referred to as Network Economy service. Network Economy is used for imports, as described in BC Hydro's response to BCUC Panel IR 2.12.3, or generators not designated as Network Resources. The scheduling priority for Network Economy is lower than for NITS from designated Network Resources, which is a firm service, and firm PTP service.

In summary, NITS allows BC Hydro to use the Transmission System to meet its instantaneous domestic demand requirements by dispatching sufficient generation from multiple designated Network Resources, supplemented by non-designated resources through the use of Network Economy, to balance its domestic loads and load obligations.

12.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-5, BCUC IR 163.1, 163.5.1, 164.1, 164.1.1
NITS and PTP Allocation to Distribution

In Exhibit B-5, BC Hydro's response to BCUC IR 163.1 states:

> BC Hydro notes that Network Load in BC Hydro's service area would not be served using PTP but instead is served by BC Hydro as the Network Customer using Network Integration Transmission Service in accordance with Part I (Common Service Provisions) and Part III (Network Integration Transmission Service) of the OATT.

BC Hydro's response to BCUC IR 164.1 states:

> Point-To-Point Allocation to Distribution on Appendix A, schedule 3.4, line 12 represents the cost to use Point-To-Point transmission service to serve domestic load customers. It is a cost borne by BC Hydro domestic load customers and is recovered through BC Hydro's bundled sales rates.

BC Hydro's response to BCUC IR 164.1.1 states:

> …Point-To-Point transmission costs are allocated to domestic load customers as they benefit from the use of the transmission system to move energy from generation facilities to their point of interconnection (e.g. on the distribution system).

2.12.2 Please confirm, or otherwise explain, whether domestic load customers pay for both NITS and PTP transmission allocated to Distribution through bundled sales rates.

RESPONSE:

Confirmed.

12.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-5, BCUC IR 163.1, 163.5.1, 164.1, 164.1.1
NITS and PTP Allocation to Distribution

BC Hydro's response to BCUC IR 163.5.1 states:

> Delivering energy from a non-designated resource on an as-available basis means transmitting energy to serve Network Load from a generation resource that has not been designated as being fully committed to serve Network Load per section 30 of the OATT. For example, imports from resources in the U.S. that are not owned or controlled by BC Hydro would constitute the delivery of energy from a non-designated generation resource on an as-available basis.
>
> The Transmission Customer must reserve Short-Term (including Network Economy) or Long-Term Transmission Service before it can schedule (deliver) energy from non-designated resources.

2.12.3 Please clarify whether PTP transmission service or Network Integration Transmission service is used when imports of (energy / capacity) are used to serve domestic load customers.

RESPONSE:

Both PTP transmission service and Network Integration Transmission service may be used when imports of energy are used to serve domestic load customers.

In most circumstances, Network Economy Service (which is part of Network Integration Transmission Service) is used when imports of energy are used to serve domestic load customers from non-designated resources. Network Economy is used, for example, when there are imports to the BC Hydro system from generators located outside of British Columbia. Network Integration Transmission Service is also used to serve domestic load customers from designated network resources, including generators in FortisBC service area with which BC Hydro has an electricity supply agreement.

However, there may be circumstances in which firm Point-To-Point reservations are required to facilitate the import of energy. For example, in circumstances where import transmission capacity is constrained, firm Point-to-Point service may be preferable to ensure sufficient import energy can be delivered to the system, as Network Economy Service has a lower curtailment priority.

13.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, p. 9-27; Exhibit B-5; Exhibit B-19, Appendix A, Schedule 3.4; Rate Schedule 1 of BC Hydro's OATT
LT PTP Transmission Rates

Page 9-27 of the Application states "The long-term PTP revenue is derived from the forecast long-term PTP volumes and the proposed long-term PTP rates. The forecasts of long-term PTP volumes are based on committed long-term transmission contracts."

Line 41 in Schedule 3.4 of Appendix A to the Evidentiary Update states that proposed rates for LT PTP transmission service in fiscal 2020 and fiscal 2021 are $81,695/MW/year and $81,546/MW/year, respectively.

Lines 55–57 of Schedule 3.4 state that the average price for LT PTP transmission service in fiscal 2020 and fiscal 2021 are $9.33/MWh and $9.31/MWh.

Rate Schedule 1 of BC Hydro's OATT states "The Reserved Capacity Charge for the Long-Term Firm Service Rate will be up to a maximum price as set out below except where the POD is a point of interconnection between the Transmission System and the transmission system of Fortis BC, Inc., in which case the rate shall be zero ($0.00)."

2.13.1 Please clarify that the proposed OATT rates for LT PTP transmission are "maximum prices" i.e. the rate agreed upon between BC Hydro and an OATT customer could be lower than the proposed rates of $81,695/MW/year and $81,546/MW/year in fiscal 2020 and fiscal 2021, respectively.

RESPONSE:

BC Hydro's practice is to charge the maximum rate for Long-Term Point-To-Point Transmission Service, as required to recover expected costs. BC Hydro currently only offers a discount rate for Hourly and Daily Short-Term Transmission Service per OATT Rate Schedule 01. Please refer to BC Hydro's response to BCUC Panel IR 2.13.2 for a discussion of why BC Hydro believes it is not appropriate to discount the rate for Long-Term Point-To-Point Transmission Service.

13.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, p. 9-27; Exhibit B-5; Exhibit B-19, Appendix A, Schedule 3.4; Rate Schedule 1 of BC Hydro's OATT
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2.13.1 Please clarify that the proposed OATT rates for LT PTP transmission are "maximum prices" i.e. the rate agreed upon between BC Hydro and an OATT customer could be lower than the proposed rates of \$81,695/MW/year and \$81,546/MW/year in fiscal 2020 and fiscal 2021, respectively.

2.13.1.1 Please clarify why the hourly equivalent price for LT PTP transmission, as stated on lines 55–57 of Schedule 3.4 is considered an "average price" when Rate Schedule 1 states that "The Reserved Capacity Charge…will be up to a maximum…".

RESPONSE:

The hourly equivalent prices shown on lines 55 through 57 of Schedule 3.4 of Appendix A are considered average prices because they are calculated by dividing Long-Term PTP Revenue on Appendix A, Schedule 3.4 lines 52 through 54 by Long-Term PTP volume (GWh) on Appendix A, Schedule 3.4 lines 49

through 51. Long-Term Point-To-Point Transmission Service is available for terms of one-year or longer and cannot be purchased on an hourly basis, hence these are equivalent hourly prices and not actual hourly prices for Long-Term service.

The maximum hourly rate on Rate Schedule 01 applies to undiscounted Short-Term Point-To-Point Transmission Service and is calculated by dividing the Long-Term Firm PTP Rate ($/MW/year) on Appendix A, Schedule 3.4, line 41 by 8,760 (hours/year). This value is the same as the hourly equivalent prices discussed above for the Fiscal 2020 and Fiscal 2021 Plan and Update, but the hourly equivalent prices may change when Actuals are determined for these years due to contract sales between internal and external customers, which cannot be forecast.

13.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, p. 9-27; Exhibit B-5; Exhibit B-19, Appendix A, Schedule 3.4; Rate Schedule 1 of BC Hydro's OATT
LT PTP Transmission Rates

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Lines 55–57 of Schedule 3.4 state that the average price for LT PTP transmission service in fiscal 2020 and fiscal 2021 are $9.33/MWh and $9.31/MWh.

Rate Schedule 1 of BC Hydro's OATT states "The Reserved Capacity Charge for the Long-Term Firm Service Rate will be up to a maximum price as set out below except where the POD is a point of interconnection between the Transmission System and the transmission system of Fortis BC, Inc., in which case the rate shall be zero ($0.00)."

2.13.2 Please explain how long-term rates on point to point contracts are established, i.e. could OATT customers negotiate an LT rate that was less than the maximum price as set out in Rate Schedule 1 at that time?

RESPONSE:

No. BC Hydro's practice is to charge the maximum rate for all Long-Term Firm Service under Rate Schedule 01 with the exception where rate harmonization with FortisBC Inc., as discussed in BC Hydro's response to BCUC Panel IR 2.8.7, is applicable. The Long-Term Firm Service Rate is established based on the Transmission Revenue Requirement and is the key rate that is intended to recover BC Hydro's costs for the provision of Point-To-Point Transmission Service. Thus, a discounted Long-Term Firm Service rate has not been taken into consideration in the Transmission Revenue Requirement. Where discounting is applicable for Short-Term rates, these rates are designed to contribute towards BC Hydro's fixed costs of service and to maximize use of transmission system capacity by providing Transmission Customers with an incentive to utilize Available Transfer Capability on unconstrained paths that might otherwise remain unused.

13.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, p. 9-27; Exhibit B-5; Exhibit B-19, Appendix A, Schedule 3.4; Rate Schedule 1 of BC Hydro's OATT
LT PTP Transmission Rates

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Line 41 in Schedule 3.4 of Appendix A to the Evidentiary Update states that proposed rates for LT PTP transmission service in fiscal 2020 and fiscal 2021 are $81,695/MW/year and $81,546/MW/year, respectively.

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2.13.2 Please explain how long-term rates on point to point contracts are established, i.e. could OATT customers negotiate an LT rate that was less than the maximum price as set out in Rate Schedule 1 at that time?

2.13.2.1 Please discuss whether service agreements for LT PTP transmission service set a fixed price for the term of each agreement, or if the price changes over the term of each contract.

RESPONSE:

The price for Long-Term Point-To-Point Transmission Service under a service agreement will change only if a new rate is approved by the Commission and comes into effect during the term of the service agreement.

14.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, pp. 9-23, 9-24; Decision and Order G-43-98 to BC Hydro's Application for Wholesale Transmission Services, dated April 23, 1998 (BC Hydro WTS Decision), p. 31
NITS and PTP Transmission Service – Calculations

Page 9-23 of the Application states:

> The NITS charge is designed to recover the TRR, less any revenues from PTP and Ancillary services, as illustrated in the following equation:

$$\text{Monthly NITS Charge} = \frac{\text{TRR} - (\text{PTP Revenue} + \text{Ancillary Services Revenue})}{12 \text{ months}}$$

Page 31 of the BC Hydro WTS Decision states:

> The Network Transmission Revenue Requirement is equal to BC Hydro's total Transmission Revenue Requirement less forecast revenues from Point-to-Point Transmission Service, grandfathered contracts and certain other small adjustments (Exhibit 2, BCUC IR 1, Question 35). Accordingly, it is the residual Transmission Revenue Requirement.

Page 9-24 of the Application states:

> PTP service is the reservation and transmission of capacity and energy, on a firm or non-firm basis, from point A to point B, on the transmission system.
>
> The PTP service rate is designed to recover the cost of the TRR if PTP transmission service were used to transfer the maximum capacity supply on the system. In theory, if there were no NITS customer, the PTP charge would recover the TRR, less ancillary service revenue. Specifically, based on the approved rate design, the PTP Transmission Service rate is based on the following:

$$\text{PTP Rate} = \frac{(\text{TRR - Ancillary Services Revenue})}{(\text{Maximum Capacity Supply})}$$

2.14.1 Please clarify whether PTP transmission service involves the reservation of capacity and energy, as stated in the preamble, and if so, why the formula to calculate the PTP rate is only based on capacity.

RESPONSE:

Point-To-Point Transmission Service involves the reservation of transmission capacity only. BC Hydro clarifies that the statement on page 9-24 of the Application quoted in the preamble above “PTP service is the reservation and transmission of capacity and energy” should have stated “PTP service is the reservation of capacity for the transmission of energy”.

The Transmission Customer that purchases the transmission service has the right to schedule energy on that capacity reservation, up to the amount of transmission reserved (megawatts), and service increment of the transmission reservation (i.e., hourly, monthly). For example, the customer pays for 100 MW of Hourly Firm PTP transmission service (the reservation capacity), and can then schedule up to 100 MW of energy during the hour for which the PTP service was reserved.

For this reason, the formula to calculate the PTP rate is only based on the capacity reserved because the Transmission Customer is paying for the capacity reserved under the appropriate OATT rate schedules, regardless of the amount of energy the customer schedules on the reservation.

14.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, pp. 9-23, 9-24; Decision and Order G-43-98 to BC Hydro's Application for Wholesale Transmission Services, dated April 23, 1998 (BC Hydro WTS Decision), p. 31
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$$\text{Monthly NITS Charge} = \frac{\text{TRR} - (\text{PTP Revenue} + \text{Ancillary Services Revenue})}{\text{12 months}}$$

Page 31 of the BC Hydro WTS Decision states:

> The Network Transmission Revenue Requirement is equal to BC Hydro's total Transmission Revenue Requirement less forecast revenues from Point-to-Point Transmission Service, grandfathered contracts and certain other small adjustments (Exhibit 2, BCUC IR 1, Question 35). Accordingly, it is the residual Transmission Revenue Requirement.

Page 9-24 of the Application states:

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>
> The PTP service rate is designed to recover the cost of the TRR if PTP transmission service were used to transfer the maximum capacity supply on the system. In theory, if there were no NITS customer, the PTP charge would recover the TRR, less ancillary service revenue. Specifically, based on the approved rate design, the PTP Transmission Service rate is based on the following:

$$\text{PTP Rate} = \frac{(\text{TRR - Ancillary Services Revenue})}{(\text{Maximum Capacity Supply})}$$

2.14.2 For the equation on page 9-24, please clarify whether the "PTP Rate" is for long term or short term PTP service.

RESPONSE:

The PTP Rate referred to in the equation on page 9-24 of the Application is for all point-to-point service unless discounted. As discussed on page 9-27 of the Application, the only discounted rates are the Short-Term PTP rates for export and wheel-through transactions.

14.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, pp. 9-23, 9-24; Decision and Order G-43-98 to BC Hydro's Application for Wholesale Transmission Services, dated April 23, 1998 (BC Hydro WTS Decision), p. 31
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Page 31 of the BC Hydro WTS Decision states:

> The Network Transmission Revenue Requirement is equal to BC Hydro's total Transmission Revenue Requirement less forecast revenues from Point-to-Point Transmission Service, grandfathered contracts and certain other small adjustments (Exhibit 2, BCUC IR 1, Question 35). Accordingly, it is the residual Transmission Revenue Requirement.

Page 9-24 of the Application states:

> PTP service is the reservation and transmission of capacity and energy, on a firm or non-firm basis, from point A to point B, on the transmission system.
>
> The PTP service rate is designed to recover the cost of the TRR if PTP transmission service were used to transfer the maximum capacity supply on the system. In theory, if there were no NITS customer, the PTP charge would recover the TRR, less ancillary service revenue. Specifically, based on the approved rate design, the PTP Transmission Service rate is based on the following:

$$\text{PTP Rate} = \frac{(\text{TRR} - \text{Ancillary Services Revenue})}{(\text{Maximum Capacity Supply})}$$

2.14.3 Please reconcile the two equations as stated in the preamble, which appear to be circular. Specifically, please address the assumption that "if there were no NITS customer, the PTP charge would recover the TRR, less ancillary service revenue," however, the NITS charge is a residual calculation that recovers the TRR, "less any revenues from PTP and Ancillary Services".

RESPONSE:

The two equations are not circular. Both the PTP Rate and the Monthly NITS Charge are derived from the Transmission Revenue Requirement, but are not calculated in the order presented in the preamble to the question.

The forecast Ancillary Services Revenue (including scheduling and dispatch) is first determined based on an estimate of the volume of Transmission reservations that attract the various Ancillary Services and the Ancillary Services Rates. This forecast revenue must be excluded from the calculation of both the PTP Rate and the Monthly NITS Charge to avoid double-recovery. Accordingly, it is included in both equations.

The PTP Rate is then determined using the PTP Rate formula (i.e., second equation in the preamble above), with ancillary services excluded. This calculates the Long-Term Firm Rate, but not the forecast revenue. To calculate the forecast revenue, the Long-Term Firm Rate is applied to an estimate of the forecast volume of Long-Term Point-To-Point during the Test Period. This is then added to the estimate of the Short-Term Point-To-Point revenue, which results in the total forecast PTP Revenue that is used in the Monthly NITS Charge equation.

Both the Ancillary Services Revenue forecast and the PTP Revenue forecast are then excluded from the calculation of the Monthly NITS Charge, which is the residual Transmission Revenue Requirement after exclusion of PTP Revenue and Ancillary Services Revenue.

Together, these steps recover the entire Transmission Revenue Requirement with no double recovery.

This approach to calculating the NITS rate was approved by the BCUC by Order No. G-58-05, dated June 19, 2005. In its Decision, the BCUC stated (at pages 14 to 15):[1]

> **BCTC proposes to maintain the format and method of calculating the NITS rate that was approved as part of the WTS Tariff. NITS allows a Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load (Exhibit B1-1,**

1 BCUC Order No. G-58-05 relating to BCTC's 2004 OATT Application, Decision p 14-15. Available at: https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/111671/1/document.do.

Appendix A, Section III, p. 62). Currently BC Hydro is BCTC's only Network Customer.

The rates for NITS collect the Network TRR, which is equal to the total BCTC TRR, net of scheduling and dispatch and engineering services, less forecast point to point revenue (Exhibit B1-4, BCUC IR 10.1). The forecast PTP revenue includes both Long Term Firm and Short Term PTP revenues.

…

The Commission Panel accepts BCTC's proposal that the total forecast ST PTP revenue be used to offset the Network TRR in the calculation of the NITS rate, given Network Customers are ultimately responsible for recovering the entire revenue requirement for the transmission system including any unused capacity that is not sold for LT or ST PTP use. The Commission Panel also supports this in light of the fact this is consistent with the FERC Order No. 888 Pro Forma tariff. …

The Commission Panel approves the proposed approach to calculate the rate for NITS.

BC Hydro has maintained this approach to calculating the NITS rate and it remains consistent with FERC's *pro forma* tariff.

15.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-5, BCUC IR 163.1, Attachment 6, p. 2
Allocation of long-term firm Available Transfer Capability (ATC)

Page 2 of Attachment 6 to BC Hydro's response to BCUC IR 163.1 states:

> If long-term firm ATC becomes available from constructing Network Upgrades in response to long-term transmission service request with the Transmission Customer subsequently executed a Service Agreement, the ATC associated with those Network Upgrades will be awarded to that Transmission Customer first.

2.15.1 Please discuss how OATT customers would be notified when long-term firm ATC along any transmission line is increased or becomes available. As part of the response, please indicate when OATT customers can begin submitting bids for LT firm ATC along any transmission path where construction projects increase ATC (i.e. are requests made during the planning phase, during construction, once construction is complete, etc.).

RESPONSE:

A Long-Term Firm Transmission Service request (TSR) can be submitted at any time on BC Hydro's Open Access Same Time Information System (OASIS). BC Hydro keeps a queue of all TSRs submitted.

When Long-Term Firm Available Transfer Capability (ATC) is increased or becomes available, BC Hydro as Transmission Provider will publish a bulletin to notify OATT customers of the increase and the amount of ATC available. If the increase in ATC is due to upgrades completed in response to a System Impact Study and/or Facilities Study that was triggered by a TSR submitted by an OATT customer(s), the Long-Term Point-To-Point Transmission Service (LT PTP) capacity will be granted first to the customer or customers that triggered and paid for the studies. Any remaining LT PTP capacity will be offered to requests in the LT PTP queue on a first-come, first-serve basis.

16.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, p. 9-27; Exhibit B-5, BCUC IR 166.6
ST PTP Transmission Service

Page 9-27 of the Application states:

> The short-term PTP (including non-firm PTP) revenue forecast reflects the discounting of short-term PTP rates on export and wheel-through transactions. The applicable rates are $3.00/MWh during High (Heavy) Load Hours and $1.00/MWh during Low (Light) Load Hours, Sundays and North American Electricity Reliability Corporation (NERC) holidays.

BC Hydro's response to BCUC IR 166.6 states:

> In its September 10, 2009 Decision on the 2008 Application, issued with BCUC Order G-102-09, the BCUC approved the Short-Term rate design proposal as filed.
>
> BC Hydro believes that the rationale provided for the Short-Term rate design in the 2008 Application remains valid.

2.16.1 Please explain whether the ST PTP rates, as established in Order G-102-09 were discounted based on LT PTP transmission rates at that time. If not, please explain how ST PTP rates were established and why.

RESPONSE:

The discounted ST PTP rates are not based on the LT PTP transmission rates at the time the discount rates were designed. The discount rates were designed through an analysis of the impact of fixed time of use prices on revenues and trade blocking. The rationale for the discounted rates is summarized on page 117 of the British Columbia Transmission Corporation (BCTC) 2008 Application to Amend the OATT, and approved through Order No. G-102-09, as follows:

> **5.5 BCTC's Proposed ST PTP Design**
>
> **Based on the analysis presented in Section 5.3, BCTC seeks to replace the existing design with a simple TOU rate design with a $3/MWh HLH rate and a $1/MWh LLH rate for the following reasons:**

(a) The proposed TOU design strikes the right balance between the competing goals of assuring that all transmission customers make positive contributions to fixed costs while continuing to promote economically-efficient levels of trade.

(b) The proposed TOU rate design with a $3/MWh HLH rate and a $1/MWh LLH rate provides for a more balanced cost contribution across all paths than would a $2/MWh HLH rate and a $1/MWh LLH rate.

(c) The proposed TOU design creates stable ST PTP rates that are not formula based, or connected to Alberta energy prices that have recently become extremely volatile. Although it is conceptually appealing to charge more for transmission during high-value hours, BCTC's assessment of its formula-based design indicates that it is difficult to do so in practice.

(d) Since the firm vs. non-firm service distinction is meaningful only in the presence of a capacity shortage, and the discounted TOU rates are only available at times where capacity is available, the proposed simple TOU design does not vary between firm and non-firm service. BCTC should not be offering ST PTP discounting during times of capacity shortages.

(e) Finally, a TOU design is easier to understand than formula-based rates and can be readily implemented on BCTC's system.

16.0 B. CHAPTER 9 – TRANSMISSION REVENUE REQUIREMENT

Reference: TRANSMISSION REVENUE REQUIREMENT
Exhibit B-1, p. 9-27; Exhibit B-5, BCUC IR 166.6
ST PTP Transmission Service

Page 9-27 of the Application states:

> The short-term PTP (including non-firm PTP) revenue forecast reflects the discounting of short-term PTP rates on export and wheel-through transactions. The applicable rates are $3.00/MWh during High (Heavy) Load Hours and $1.00/MWh during Low (Light) Load Hours, Sundays and North American Electricity Reliability Corporation (NERC) holidays.

BC Hydro's response to BCUC IR 166.6 states:

> In its September 10, 2009 Decision on the 2008 Application, issued with BCUC Order G-102-09, the BCUC approved the Short-Term rate design proposal as filed.
>
> BC Hydro believes that the rationale provided for the Short-Term rate design in the 2008 Application remains valid.

2.16.1 Please explain whether the ST PTP rates, as established in Order G-102-09 were discounted based on LT PTP transmission rates at that time. If not, please explain how ST PTP rates were established and why.

2.16.1.1 Please explain why ST PTP rates as established in Order G-102-09 remain valid. As part of your response, please discuss the conditions under which the ST PTP rates were established, and why the ST PTP rates and rate design continue to be valid in the test period.

RESPONSE:

The current ST PTP discount rates were established in response to the poor price prediction accuracy of the formula-based Short Term Point-To-Point (ST PTP) rates that were in place previously, and resulting decline in ST PTP revenue. The formula-based ST PTP rates were replaced with fixed Time-of-Use (TOU) rates as approved by Order No. G-102-09 and as discussed in BC Hydro's response to BCUC Panel IR 2.16.1.

The ST PTP rate design continues to be valid as the main markets that border British Columbia (Alberta and the Pacific Northwest) are still fundamentally the same as at the time of Order No. G-102-09, and the fixed time-of-use rates continue to be simple, easy to understand, stable, and help balance the objectives of promoting use of the transmission system and cost recovery.

BC Hydro would consider revisiting the ST PTP rate if the main electricity markets that border B.C. change, and BC Hydro foresees an opportunity to increase revenues associated with ST PTP transmission service. BC Hydro does not currently see an opportunity to increase the contribution of ST PTP revenues toward cost recovery.

17.0 C. DEBT MANAGEMENT REGULATORY ACCOUNT

Reference: Debt Management Regulatory Account
Exhibit B-11, Appendix D, p. 2; Table D-2, p. 4; Exhibit B-17, AMPC IR 3.14.4, Attachment 1 to AMPC IR 3.14.2, 3.14.6, 3.14.7.2; BC Hydro 2019/2020 Second Quarter Report, Note 9 to the unaudited condensed consolidated interim financial statements for the three and six months ended September 30, 2019[1]
Forecast account balances

Table D-2 in Appendix D to the Evidentiary Update provides the historical actual and forecast balances of the Debt Management Regulatory Account for F2017 to F2024. For the actual F2019 balance and the F2020 forecast balance, they are shown as $163 million and $276 million, respectively.

BC Hydro's F2020 second quarter financial statements show the September 30, 2019 balance of the Debt Management Regulatory Account as $592 million.

2.17.1 Please explain the $429 million[2] change in the Debt Management Regulatory Account from the end of F2019 to September 30, 2019.

RESPONSE:

The $429 million change in the Debt Management Regulatory Account from March 31, 2019 to September 30, 2019 was due to a decrease in forward interest rates. Forward interest rates are the market's estimate of future interest rates at the time the hedge is to be settled and are required to be used to value the future debt hedges under accounting rules. The change in future estimated interest rates result in unrealized gains/(losses). As forward interest rates are constantly changing, the unrealized value will continue to change until settlement occurs.

Once the interest rate hedge is settled, the realized gain (loss) is a result of the actual difference between the market interest rates and the hedge rate on the date of settlement. For additional clarity and for the purposes of answering this series of questions, the table below shows the components and balance of the Debt Management Regulatory Account balance at various points in time.

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1 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/quarterly-reports/F20-Q2-Report.pdf.

2 $429 million = $592 million - $163 million

$ millions	September 30, 2018 (Application & Q2 Financial Statements)	March 31, 2019 (Annual Financial Statements)	May 31, 2019 (Evidentiary Update)	September 30, 2019 (Q2 Financial Statements)	December 31, 2019
Realized Gains/(Losses)	122	122	96	73	71
Unrealized Gains/(Losses)	138	(285)	(360)	(659)	(320)
Amortization	nil	nil	(2)	(6)	(9)
Total DMRA	260	(163)	(266)	(592)	(258)
Increase/ (Decrease) From Prior Value	nil	(423)	(103)	(326)	334

The above table illustrates the following:

- **The Debt Management Regulatory Account is sensitive to changes in forward interest rates;**
- **The balance in the Debt Management Regulatory Account continues to fluctuate as forward rates move up or down and should be expected to continue to fluctuate; and**
- **Most gains/losses are not yet realized.**

In accordance with BCUC Order No. G-42-16, realized and unrealized gains/(losses) are added to the Debt Management Regulatory Account. However, also in accordance with that Order, only realized gains/(losses) are amortized starting in the test period following settlement (i.e., realization). As a result, any fluctuations in the form of unrealized gains/losses, and any realized gains and losses on settled debt hedges in the Test Period as well as the corresponding impacts to the Debt Management Regulatory Account, will not impact rates in the Test Period.

17.0 C. DEBT MANAGEMENT REGULATORY ACCOUNT

Reference: Debt Management Regulatory Account
Exhibit B-11, Appendix D, p. 2; Table D-2, p. 4; Exhibit B-17, AMPC IR 3.14.4, Attachment 1 to AMPC IR 3.14.2, 3.14.6, 3.14.7.2; BC Hydro 2019/2020 Second Quarter Report, Note 9 to the unaudited condensed consolidated interim financial statements for the three and six months ended September 30, 2019[1]
Forecast account balances

Table D-2 in Appendix D to the Evidentiary Update provides the historical actual and forecast balances of the Debt Management Regulatory Account for F2017 to F2024. For the actual F2019 balance and the F2020 forecast balance, they are shown as $163 million and $276 million, respectively.

BC Hydro's F2020 second quarter financial statements show the September 30, 2019 balance of the Debt Management Regulatory Account as $592 million.

2.17.2 Given that the balance in the Debt Management Regulatory Account has increased to $592 million as at the end of the second quarter of F2020, please discuss whether BC Hydro's current forecast ending balances for F2020 to F2024 are different from the balances provided in the Evidentiary Update.

RESPONSE:

BC Hydro's current forecast ending balances in the Debt Management Regulatory Account (DMRA) for fiscal 2020 to fiscal 2024 are slightly lower than the balances in the Evidentiary Update.

The updated forecast ending balances based on the actual balance as at December 31, 2019 are shown in the table below:

1 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/quarterly-reports/F20-Q2-Report.pdf

DMRA Ending Balance, $ millions	F2020	F2021	F2022	F2023	F2024
Based on December 31, 2019 DMRA balance	261.1	273.5	282.6	286.0	284.9
Evidentiary Update	276.5	288.9	296.5	297.6	293.6
Variance	(15.4)	(15.4)	(13.9)	(11.5)	(8.7)

BC Hydro notes the following in respect of the above:

- **The forecast balance for fiscal 2020 is lower than the $592 million actual balance at September 30, 2019 as losses have been reduced since then, due to an increase in forward interest rates. Forecast and actual balances are expected to continue to fluctuate as a result of changing forward interest rates;**
- **Unrealized gains/losses do not impact ratepayers until the hedges are settled, at which time gains/losses become realized. Unrealized gains/losses captured in the DMRA will constantly change with fluctuations in market forward rates but ratepayers will not be immediately impacted by such changes in the DMRA balance; and**
- **Fluctuations since the Evidentiary Update do not impact Test Period rates as only <u>realized</u> gains/losses impact rates via amortization of the account balance, and this starts in the next test period in accordance with BCUC Order No. G-42-16. Please refer to BC Hydro's response to BCUC Panel IR 2.17.1 for further information on the amortization of gains and losses from the DMRA.**

17.0 C. DEBT MANAGEMENT REGULATORY ACCOUNT

Reference: Debt Management Regulatory Account
Exhibit B-11, Appendix D, p. 2; Table D-2, p. 4; Exhibit B-17, AMPC IR 3.14.4, Attachment 1 to AMPC IR 3.14.2, 3.14.6, 3.14.7.2; BC Hydro 2019/2020 Second Quarter Report, Note 9 to the unaudited condensed consolidated interim financial statements for the three and six months ended September 30, 2019[1]
Forecast account balances

Table D-2 in Appendix D to the Evidentiary Update provides the historical actual and forecast balances of the Debt Management Regulatory Account for F2017 to F2024. For the actual F2019 balance and the F2020 forecast balance, they are shown as $163 million and $276 million, respectively.

BC Hydro's F2020 second quarter financial statements show the September 30, 2019 balance of the Debt Management Regulatory Account as $592 million.

2.17.2 Given that the balance in the Debt Management Regulatory Account has increased to $592 million as at the end of the second quarter of F2020, please discuss whether BC Hydro's current forecast ending balances for F2020 to F2024 are different from the balances provided in the Evidentiary Update.

2.17.2.1 If so, please provide the updated forecast ending balances of the Debt Management Regulatory Account for each of F2020 to F2024.

RESPONSE:

Please refer to BC Hydro's response to BCUC Panel IR 2.17.2.

1 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/quarterly-reports/F20-Q2-Report.pdf.

17.0 C. DEBT MANAGEMENT REGULATORY ACCOUNT

Reference: Debt Management Regulatory Account
Exhibit B-11, Appendix D, p. 2; Table D-2, p. 4; Exhibit B-17, AMPC IR 3.14.4, Attachment 1 to AMPC IR 3.14.2, 3.14.6, 3.14.7.2; BC Hydro 2019/2020 Second Quarter Report, Note 9 to the unaudited condensed consolidated interim financial statements for the three and six months ended September 30, 2019[1]
Forecast account balances

Table D-2 in Appendix D to the Evidentiary Update provides the historical actual and forecast balances of the Debt Management Regulatory Account for F2017 to F2024. For the actual F2019 balance and the F2020 forecast balance, they are shown as $163 million and $276 million, respectively.

BC Hydro's F2020 second quarter financial statements show the September 30, 2019 balance of the Debt Management Regulatory Account as $592 million.

2.17.2 Given that the balance in the Debt Management Regulatory Account has increased to $592 million as at the end of the second quarter of F2020, please discuss whether BC Hydro's current forecast ending balances for F2020 to F2024 are different from the balances provided in the Evidentiary Update.

2.17.2.2 If not, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to BCUC Panel IR 2.17.2 where we explain that the forecast ending balances of Debt Management Regulatory Account for fiscal 2020 to fiscal 2024 are forecast to be different from the Evidentiary Update.

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[1] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/quarterly-reports/F20-Q2-Report.pdf.

17.0 C. DEBT MANAGEMENT REGULATORY ACCOUNT

Reference: Debt Management Regulatory Account
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Forecast account balances

In response to AMPC IR 3.14.4, BC Hydro provided an Excel worksheet labelled "FDH EU," which shows the details by individual hedge that make up the additions to the Debt Management Regulatory Account fiscal 2020 in the Evidentiary Update.

As part of the response, BC Hydro stated that the forecast F2020 balance of the Debt Management Regulatory Account is based on the realized and unrealized hedge values as of May 31, 2019.

Note 9 to BC Hydro's F2020 second quarter financial statements show $423 million of additions to the Debt Management Regulatory Account from the end of F2019 to September 30, 2019.

2.17.3 Please update the "FDH EU" worksheet to show the calculation of the $423 million addition to the Debt Management Regulatory Account for the six-month period ending in September 30, 2019.

RESPONSE:

Please refer to the "FDH September 2019" working Excel worksheet which is provided as Attachment 1 to this response for an updated version of the "FDH EU" worksheet, showing the $423 million addition to the Debt Management Regulatory Account for the six-month period ending September 30, 2019. In the attachment to this response, the $423 million is seen at the bottom right of the second page under the column heading "Fiscal 2020 Addition to DMRA".

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[1] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/quarterly-reports/F20-Q2-Report.pdf.

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17.0 C. DEBT MANAGEMENT REGULATORY ACCOUNT

Reference: Debt Management Regulatory Account
Exhibit B-11, Appendix D, p. 2; Table D-2, p. 4; Exhibit B-17, AMPC IR 3.14.4, Attachment 1 to AMPC IR 3.14.2, 3.14.6, 3.14.7.2; BC Hydro 2019/2020 Second Quarter Report, Note 9 to the unaudited condensed consolidated interim financial statements for the three and six months ended September 30, 2019[1]
Forecast account balances

In response to AMPC IR 3.14.4, BC Hydro provided an Excel worksheet labelled "FDH EU," which shows the details by individual hedge that make up the additions to the Debt Management Regulatory Account fiscal 2020 in the Evidentiary Update.

As part of the response, BC Hydro stated that the forecast F2020 balance of the Debt Management Regulatory Account is based on the realized and unrealized hedge values as of May 31, 2019.

Note 9 to BC Hydro's F2020 second quarter financial statements show $423 million of additions to the Debt Management Regulatory Account from the end of F2019 to September 30, 2019.

2.17.3 Please update the "FDH EU" worksheet to show the calculation of the $423 million addition to the Debt Management Regulatory Account for the six-month period ending in September 30, 2019.

2.17.3.1 For the Evidentiary Update, BC Hydro used the hedge values as at May 31, 2019. Please identify the date that the realized and unrealized hedge values were based on to produce the financial statements for the six months ended September 30, 2019.

RESPONSE:

The realized hedge values reported in the September 30, 2019 financial statements were as at the date that the hedges were settled (i.e., the settlement date) and the unrealized hedge values were as at September 30, 2019.

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1 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/quarterly-reports/F20-Q2-Report.pdf.

The unrealized hedged values in the Evidentiary Update were based on the rates available at the time the forecast inputs were finalized, which was May 31, 2019. However, even if more current rates were used to value the future debt hedges, there would not be an impact to the current test period as only realized gains/(losses) are collected from/returned to ratepayers via amortization and this does not occur until starting in the test period following settlement (i.e., realization), in accordance with BCUC Order No. G-42-16.

Please refer to BC Hydro's response to BCUC Panel IR 2.17.1 for additional details.

17.0 C. DEBT MANAGEMENT REGULATORY ACCOUNT

Reference: Debt Management Regulatory Account
Exhibit B-11, Appendix D, p. 2; Table D-2, p. 4; Exhibit B-17, AMPC IR 3.14.4, Attachment 1 to AMPC IR 3.14.2, 3.14.6, 3.14.7.2; BC Hydro 2019/2020 Second Quarter Report, Note 9 to the unaudited condensed consolidated interim financial statements for the three and six months ended September 30, 2019[1]
Forecast account balances

In response to AMPC IR 3.14.4, BC Hydro provided an Excel worksheet labelled "FDH EU," which shows the details by individual hedge that make up the additions to the Debt Management Regulatory Account fiscal 2020 in the Evidentiary Update.

As part of the response, BC Hydro stated that the forecast F2020 balance of the Debt Management Regulatory Account is based on the realized and unrealized hedge values as of May 31, 2019.

Note 9 to BC Hydro's F2020 second quarter financial statements show $423 million of additions to the Debt Management Regulatory Account from the end of F2019 to September 30, 2019.

2.17.3 Please update the "FDH EU" worksheet to show the calculation of the $423 million addition to the Debt Management Regulatory Account for the six-month period ending in September 30, 2019.

2.17.3.2 Of the $592 million ending balance in the Debt Management Regulatory Account, please identify the hedges that have been realized.

RESPONSE:

Please refer to the first page of the working Excel worksheet, which is provided as Attachment 1 to this response, for all hedges that have been realized (i.e., settled). The total line at the bottom of the page shows that as at September 30, 2019, $4.575 billion of the $10.0 billion of future debt hedges had been realized with a net gain of $73 million. This information is a compilation of the realized hedges included in Attachment 1 of BCUC Panel IR 2.17.3 (which are shown in that response in blue).

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[1] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/quarterly-reports/F20-Q2-Report.pdf.

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17.0 C. DEBT MANAGEMENT REGULATORY ACCOUNT

Reference: Debt Management Regulatory Account
Exhibit B-11, Appendix D, p. 2; Table D-2, p. 4; Exhibit B-17, AMPC IR 3.14.4, Attachment 1 to AMPC IR 3.14.2, 3.14.6, 3.14.7.2; BC Hydro 2019/2020 Second Quarter Report, Note 9 to the unaudited condensed consolidated interim financial statements for the three and six months ended September 30, 2019[1]
Forecast account balances

In response to AMPC IR 3.14.4, BC Hydro provided an Excel worksheet labelled "FDH EU," which shows the details by individual hedge that make up the additions to the Debt Management Regulatory Account fiscal 2020 in the Evidentiary Update.

As part of the response, BC Hydro stated that the forecast F2020 balance of the Debt Management Regulatory Account is based on the realized and unrealized hedge values as of May 31, 2019.

Note 9 to BC Hydro's F2020 second quarter financial statements show $423 million of additions to the Debt Management Regulatory Account from the end of F2019 to September 30, 2019.

2.17.3 Please update the "FDH EU" worksheet to show the calculation of the $423 million addition to the Debt Management Regulatory Account for the six-month period ending in September 30, 2019.

2.17.3.3 If applicable, please provide an updated "FDH EU" worksheet with the most current realized and unrealized hedge values to show the current forecast F2020 additions to the Debt Management Regulatory Account.

RESPONSE:

Please refer to the "FDH December 2019" worksheet in Attachment 1 to this response for the most current updated version of the "FDH-EU" worksheet. In the hardcopy attachment to this response, the balance at the bottom right of the second page under the column heading "Fiscal 2020 Addition to DMRA" shows the $86 million year-to-date addition to the Debt Management Regulatory Account

[1] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/quarterly-reports/F20-Q2-Report.pdf

(DMRA) for realized and unrealized losses during the nine-month period ending December 31, 2019.

The DMRA balance at December 31, 2019 (i.e., balance of $258 million) changed from September 30, 2019 (i.e., balance of $592 million) due to an increase in forward interest rates which resulted in an increase in the value of the future debt hedges. Please refer to BC Hydro's response to BCUC Panel IR 2.17.1 for a summary of the fluctuations in the DMRA at various points in time.

Changes in the value of future debt hedges within a test period do not impact ratepayers in the current test period as any changes in value are transferred to the DMRA and only recovered once realized via amortization starting in the next test period in accordance with BCUC Order No. G-42-16. Please refer to BC Hydro's response to BCUC Panel IR 2.17.1 for additional details.

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17.0 C. DEBT MANAGEMENT REGULATORY ACCOUNT

Reference: Debt Management Regulatory Account
Exhibit B-11, Appendix D, p. 2; Table D-2, p. 4; Exhibit B-17, AMPC IR 3.14.4, Attachment 1 to AMPC IR 3.14.2, 3.14.6, 3.14.7.2; BC Hydro 2019/2020 Second Quarter Report, Note 9 to the unaudited condensed consolidated interim financial statements for the three and six months ended September 30, 2019[1]
Forecast account balances

On page 2 of Appendix D to the Evidentiary Update, BC Hydro states the following regarding the forecast F2020 and F2021 balance in the Debt Management Regulatory Account:

> The increase is mostly non-cash (only a small portion relates to hedges that have realized and were settled in cash) and will be offset by lower finance charges when the hedged future debt is issued at lower interest rates.

In response to AMPC IR 3.14.7.2, BC Hydro states:

> Over the life of hedged bond issuances (10-years and 30-years), the gains or losses on hedging and the related higher or lower interest rates on the associated debt issuances largely offset. Therefore, although the decrease to long-term and short-term debt costs in the test years appears to be small relative to the additions to the DMRA, if the comparison is made over the entire term of the associated debt issuances, increases to the DMRA will be largely offset by lower interest costs on the associated debt issuances.

2.17.4 Please clarify how the gains or losses on hedging and the related higher or lower interest rates on the associated debt issuances largely offset. Please provide an illustrative example as part of the explanation.

RESPONSE:

Future Debt Hedges (FDHs) fluctuate in value before they are settled as forward interest rates change. If forward interest rates increase/decrease relative to the hedged rate then the FDHs will incur an unrealized gain/loss. However, any actual

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1 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/quarterly-reports/F20-Q2-Report.pdf.

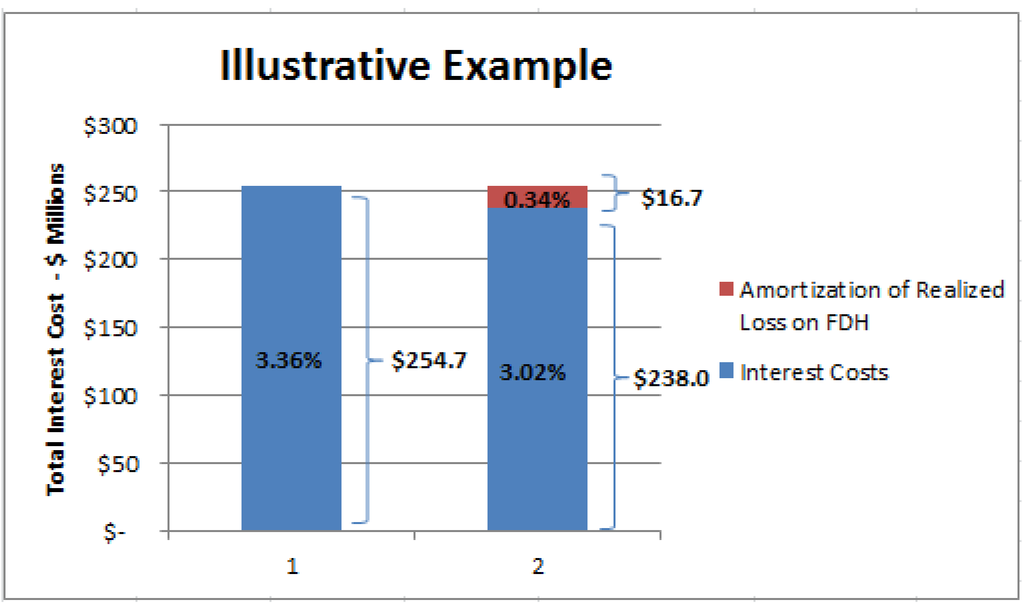
gain/loss on the FDHs will be offset by higher/lower interest costs when the associated future debt is issued.

As an illustrative example, on September 28, 2017 BC Hydro entered into a 30-year FDH to fix the interest rate at approximately 3.36 per cent on a $250.0 million forecast debt issuance in September 2018. As a result, BC Hydro locked in total future interest costs of $254.7 million.

When the $250.0 million debt was issued on August 24, 2018, market interest rates had decreased to 3.02 per cent. This decrease in interest rates resulted in a loss on the FDH of $16.7 million that was recognized in the Debt Management Regulatory Account (please refer to the "FDH September 2019" worksheet in Attachment 1 to BC Hydro's response to BCUC Panel IR 2.17.3 (the second page of the attachment) which shows the $16.7 million loss in the "Settlement Value" column). However, BC Hydro was able to issue the debt at an effective interest rate of 3.02 per cent for total interest costs of $238.0 million which was $16.7 million ($254.7 million less $238.0 million) lower than originally forecast. It is this savings of $16.7 million in interest costs on the debt issue that will offset the $16.7 million loss on the FDH.

As a result, the $16.7 million FDH loss is offset by $16.7 million in lower interest costs on the debt and ratepayers pay the net cost of $254.7 million over the life of the associated debt issue which is equivalent to the hedged interest rate of 3.36 per cent, which was the objective of the interest rate hedge - to lock in the interest rate for cost certainty purposes.

A graphical representation of this is shown in the chart below.



17.0 C. DEBT MANAGEMENT REGULATORY ACCOUNT

Reference: Debt Management Regulatory Account
Exhibit B-11, Appendix D, p. 2; Table D-2, p. 4; Exhibit B-17, AMPC IR 3.14.4, Attachment 1 to AMPC IR 3.14.2, 3.14.6, 3.14.7.2; BC Hydro 2019/2020 Second Quarter Report, Note 9 to the unaudited condensed consolidated interim financial statements for the three and six months ended September 30, 2019[1]
Forecast account balances

In response to AMPC IR 3.14.6, BC Hydro describes its current hedging strategy and states:

> BC Hydro reviews and updates its debt management strategy on an annual basis as part of the formulation of the upcoming year's Liability Risk Management Annual Strategic Plan. BC Hydro monitors the strategy on an ongoing basis, updating it when and as appropriate.

2.17.5 Please discuss whether the balance in the Debt Management Regulatory Account impacts BC Hydro's debt management strategy. If so, please explain how the debt management strategy has been updated as a result of the increase in the Debt Management Regulatory Account balance in F2020.

RESPONSE:

The balance in the Debt Management Regulatory Account does not impact BC Hydro's debt management strategy. As discussed in BC Hydro's responses to AMPC IRs 3.14.6, 3.14.7.1, and 3.14.7.2, the purpose of the hedging component of BC Hydro's debt management strategy is to achieve increased cost certainty, given BC Hydro's significant capital plan and borrowing requirements, which the hedging program has achieved. BC Hydro has been able to lock-in low interest rates to the benefit of ratepayers – these rates have been lower than future interest rates forecast by the Government of B.C. and lower than BC Hydro's weighted average cost of debt.

The balance of the Debt Management Regulatory Account is driven by the change in market interest rates relative to hedged rates.

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1 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/quarterly-reports/F20-Q2-Report.pdf.

BC Hydro reviews and updates its debt management strategy on an annual basis as part of the formulation of the upcoming year's Liability Risk Management Annual Strategic Plan. BC Hydro monitors the strategy on an ongoing basis, updating it when and as appropriate.

18.0 D. PRESCRIBED UNDERTAKINGS UNDER THE CLEAN ENERGY ACT AND GREENHOUSE GAS REDUCTION (CLEAN ENERGY) REGULATION

Reference: CHAPTER 10 – DEMAND SIDE MANAGEMENT
Exhibit B-1, Appendix Y, pp. 3, 8, 10–11; Exhibit B-1, Appendix BB, pp. 1–4, 10, 16 Prescribed undertakings

Page 3 of Appendix Y to BC Hydro's Application states:

> **…** the Low Carbon Electrification (LCE) Demand-Side Management (DSM) Projects/Programs that we have undertaken and plan to undertake over fiscal 2019, fiscal 2020 and fiscal 2021. All of our LCE DSM Projects/Programs are within one or more class of undertakings prescribed under the Greenhouse Gas Reduction (Clean Energy) Regulation, issued under section 18 of the Clean Energy Act.

Table 2-1 on page 8 of Appendix Y outlines BC Hydro's expenditures for the Initial LCE Projects for 2018 - 2022, at a total cost of $29.71M.

Table 3-2 on page 11 of Appendix Y outlines BC Hydro Funded Low Carbon Electrification Program Expenditures for 2018 – 2022, at a total cost of $16.65M.

Pages 1–4 of Appendix BB, Attachment 2 - Fiscal 2018 Annual Report No. 1 state:

> The GGRR Reporting Requirements also requests a report by a Fairness Advisor on the competitiveness of any call process held during the reporting period. BC Hydro confirms that in Fiscal 2018 it did not hold any call processes in regard to its LCE DSM Project/Programs or its LCE Infrastructure Projects.

Table 2 in Appendix BB sets out Electrification Information for LCE DSM Projects/Programs for Year Ending March 31, 2018 and shows the actual cost at $0.22M. Table 5 in Appendix BB sets out the LCE Infrastructure Projects Results as of March 31, 2018.

2.18.1 Has BC Hydro prepared a Fiscal 2019 GGRR Annual Report?

RESPONSE:

Yes. Attachment 1 to this response provides the Greenhouse Gas Reduction (Clean Energy) Regulation Fiscal 2019 Annual Report that was submitted to the Ministry of Energy, Mines and Petroleum Resources and filed with the BCUC on June 28, 2019.

The public version of this attachment redacts customer-specific information. An un-redacted version is being made available to the BCUC only.

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

June 28, 2019

GHG Reduction (Clean Energy) Regulation Reporting
Director, Communities and Transportation
Electricity and Alternative Energy Division
Ministry of Energy, Mines and Petroleum Resources
Email: GGRRReporting@gov.bc.ca

British Columbia Utilities Commission
GHG Reduction (Clean Energy)
Regulation Reporting

Email: commission.secretary@bcuc.com

RE: Ministry of Energy, Mines and Petroleum Resources (MEMPR or Ministry)
British Columbia Hydro and Power Authority (BC Hydro)
Greenhouse Gas Reduction (Clean Energy) Regulation Reporting
Fiscal 2019 Annual Report

BC Hydro writes to submit the Business Information and Declaration (Attachment 1), the Fiscal 2019 Greenhouse Gas Reduction Regulation (**GGRR**) Annual Report (**Report**) (Attachment 2) and LCE Program Results in an excel format (Attachment 3). The Report includes results for the period from April 1, 2018 to March 31, 2019 (**Fiscal 2019**) for BC Hydro's prescribed undertakings as defined in section 4 of the GGRR.

Under section 18 of the *Clean Energy Act*, a public utility implementing prescribed undertakings defined in the GGRR, must submit to the MEMPR a report respecting the prescribed undertaking. Specifically, section 18(5) states that "a report to be submitted under section (4) must include the information the minister specifies and be submitted in the form and by the time the minister specifies."

In April 2018, Ministry staff issued the GGRR reporting requirements. The reporting requirements state that an annual report is due by June 30 of each year and prescribed the form of the report.

BC Hydro is redacting customer-specific information in this version of the Report. An un-redacted version of the Report is being filed with the Ministry and BCUC only under separate cover.

BC Hydro
Power smart

For further information, please contact Geoff Higgins at 604-623-4121 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

cu/ma

Enclosures (3)

Greenhouse Gas Reduction (Clean Energy) Regulation Reporting

Attachment 1
Business Information and Declaration

BC Hydro
Power smart

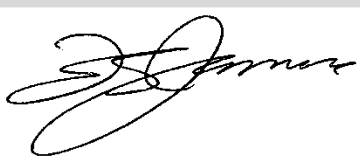
Attachment 1
Business Information and Declaration

Business Information and Declaration

<table>
<tr><th>Full Legal and Operating Name</th><th>Address Including Postal Code and Email</th><th>Telephone</th></tr>
<tr><td>British Columbia Hydro and Power Authority</td><td>333 Dunsmuir Street,
Vancouver BC V6B 5R3</td><td>604-623-4046</td></tr>
<tr><td>Reporting Period:</td><td colspan="2">April 1, 2018 to March 31, 2019 (Fiscal 2019)</td></tr>
<tr><td colspan="3">I understand that the information in this report is collected for the purposes of administering the Greenhouse Gas Reduction (Clean Energy) Regulation under the authority of the Clean Energy Act and section 26 of the Freedom of Information and Protection of Privacy Act.

I certify that records evidencing each matter reported under the Greenhouse Gas Reduction (Clean Energy) Regulation (the Regulation) Reporting Requirements are available on request.

I certify that a record evidencing my authority to submit this report on behalf of the public utility is available on request.

I certify that the information in this report is true and complete to the best of my knowledge and I understand that I may be required to provide to the Ministry of Energy, Mines and Petroleum Resources or the Commission records evidencing the truth of that information.</td></tr>
<tr><th>Signature of Authorized Signing Authority</th><th>Name and Title of Authorized Signing Authority (please print)</th><th>Date Signed YYYY/MM/DD</th></tr>
<tr><td></td><td>Fred James
Chief Regulatory Officer</td><td>June 28, 2019</td></tr>
</table>

Greenhouse Gas Reduction (Clean Energy) Regulation Reporting

Attachment 2

Fiscal 2019 Annual Report No. 2

April 2018 to March 2019

PUBLIC

Table of Contents

List of Tables

1 Executive Summary

This is BC Hydro's second annual report regarding its programs and projects that are "prescribed undertakings" as defined in the Greenhouse Gas Reduction (Clean Energy) Regulation (**GGRR**) for the purposes of section 18 of the *Clean Energy Act* (**CEA**). It is provided in response to the December 2018 "British Columbia Greenhouse Gas Reduction (Clean Energy) Regulation Reporting Requirements" (**Reporting Requirements**) provided to BC Hydro by the Ministry of Energy, Mines and Petroleum Resources. The report covers the annual period from April 1, 2018 to March 31, 2019 (**Fiscal 2019**).

In Fiscal 2019, BC Hydro provided supporting resources for two new Low Carbon Electrification (**LCE**) studies and two new LCE projects as further described in section 3.2 below. In addition to these studies and projects, BC Hydro undertook public awareness campaign activities that are also undertakings prescribed under section 4(3)(a) of the GGRR. Collectively, BC Hydro refers to these undertaking activities that fall within a class of undertakings prescribed under sections 4(3)(a)(i), 4(3)(a)(ii), 4(3)(b)(i), 4(3)(b)(ii), 4(3)(c) and 4(3)(d) of the GGRR as LCE Programs. The expenditure for the LCE Programs in Fiscal 2019 is $7.1 million.

BC Hydro also made significant progress on the Peace Region Electricity Supply (**PRES**) Project, which is an undertaking under section 4(2) of the GGRR. In Fiscal 2019, actual expenditure on the PRES Project was $48.4 million, with a cumulative cost of $69.9 million as of the end of the reporting period. It is premature to report any avoided greenhouse gas emissions for the PRES Project as it is not in-service. Total expenditures of $1.6 million were incurred in Fiscal 2019 with respect to a [redacted] generation agreement BC Hydro entered into with [redacted] to ensure the provision of reliable electricity service from the transmission system [redacted] until the PRES Project is placed in service. This is also an undertaking under section 4(2) of the GGRR.

2 State of the Market and Program Planning

2.1 Background

In December 2018, the Government of B.C. launched the CleanBC Plan, which set out a pathway to enable the government to meet its 2030 greenhouse gas (**GHG**) emission targets. The CleanBC Plan calls for BC Hydro to continue to make investments in our transmission system to make it easier for large industrial operations to access clean electricity.

In February 2019, the Minister's Mandate Letter to BC Hydro included an expectation for BC Hydro to continue to provide leadership in advancing the government's climate action strategies, including through electrification, fuel switching, and energy efficiency initiatives in the built environment, transportation, oil and gas, and other sectors.

Section 18(1) of the CEA empowers the Lieutenant Governor in Council to prescribe, by regulation, classes of undertakings for the purpose of reducing GHG emissions. Public utilities that choose to engage in undertakings that are within one or more prescribed class of undertaking are assured of being able to recover the costs of the undertaking in their rates, and may not be prevented by the British Columbia Utilities Commission from engaging in the undertaking. The GGRR was first issued in 2012, and amended in 2017 to include eight new classes of electrification undertakings. Together, CEA section 18 and the GGRR provide one of the statutory pillars of the Government of B.C.'s GHG emission reduction policy.

The eight new classes of electrification undertaking prescribed by GGRR section 4 can be divided into two broad categories: (i) those that are program based, similar to BC Hydro's demand-side management programs;[1] and (ii) those that are infrastructure based.[2] BC Hydro refers to its undertakings that fall within one of the classes in the former category as LCE Programs, and to its undertakings that fall within one of the classes in the latter category as LCE Infrastructure Projects. This nomenclature corresponds to the "Electrification Programs" referred to in subsection 6.8 of the GGRR Reporting Requirements, and "Transmission, Distribution and Generation" referred to in subsection 6.9 of the GGRR Reporting Requirements, respectively.

As noted, one of the legal consequences of the public utility program or project being a "prescribed undertaking" is that the public utility is entitled to recover the costs of the program or project in its rates. That legal consequence is meaningful only if the costs associated with particular programs and projects that are prescribed undertakings can be identified and thus are accounted for by the public utility.[3] Accordingly, the prescribed undertakings described in this Fiscal 2019 GGRR Annual Report are those programs and projects with recorded costs in Fiscal 2019.

2.2 State of the Market Discussion

This section presents an overview of the LCE market with respect to BC Hydro's activities in Fiscal 2019. Detailed information on the LCE Programs and LCE Infrastructure Projects is set out in section 3 and section 4 respectively below.

1 Being the classes of undertaking prescribed by subsections 4(3)(a)(i), 4(3)(a)(ii), 4(3)(b)(i), 4(3)(b)(ii), 4(3)(c) and 4(3)(d) of the GGRR. Under section 4(3)(c) and (d) of the GGRR, undertakings can be both projects or programs. For simplicity, BC Hydro may refer to projects under these sections as programs as well or use projects/program interchangeably.

2 Being the classes of undertaking prescribed by subsections 4(2) and 4(3)(e) of the GGRR.

3 BC Hydro notes that the costs it incurs with regard to its LCE programs are all deferred to the DSM Regulatory Account, pursuant to Order in Council No. 100, issued March 1, 2017. Generally, the costs it incurs in regard to its LCE Infrastructure Projects are capitalized.

BC Hydro is forecast to be in an energy surplus position for an extended period of time. During this surplus period, the LCE-driven incremental electricity sales will increase BC Hydro's revenues and can make rates lower than they otherwise would have been to the extent there is a positive differential between domestic electricity rates and forecast export prices. Such incremental electricity sales are also expected to reduce GHG emissions from what they otherwise would have been, thus having an environmental benefit.

Pursuant to the Reporting Requirements, a report by a Fairness Advisor must be provided on the competitiveness of any call process held during the reporting period. BC Hydro confirms that in Fiscal 2019 it did not hold any call processes in regard to its LCE Programs or its LCE Infrastructure Projects. Accordingly, no Fairness Advisor report is required.

2.3 Government Program

In Fiscal 2019, BC Hydro became responsible for delivering the CleanBC Better Buildings program (initially called EfficiencyBC) on behalf of the Government of B.C. The CleanBC Better Buildings program is a $24 million program funded by the provincial and federal governments that provides financial incentives to help households and businesses save energy and reduce GHG emissions by switching to high efficiency heating equipment and making building envelope improvements. BC Hydro is delivering the component of the CleanBC Better Buildings program that helps customers switch from fossil fuels to clean electricity. While activities under this program are funded by the Government of B.C. and are not part of BC Hydro's LCE Programs, the CleanBC program influences what programs BC Hydro funds as it seeks to align with the programs and projects funded by the CleanBC program. BC Hydro's programs that complement the CleanBC Better Buildings program are discussed in section 3 below.

3 LCE Programs

3.1 Overview

In Fiscal 2019, BC Hydro spent $7.1 million for its LCE Programs, including two new studies under section 4(3)(c) of the GGRR, two new projects under section 4(3)(a) of the GGRR, and public awareness campaign activities under section 4(3)(a) of the GGRR. These LCE undertakings are discussed in section 3.2.

In Fiscal 2019, there were a further five individual LCE projects for which BC Hydro made new funding commitments of approximately $1.3 million, but there are no expenditures in BC Hydro's financial reporting for Fiscal 2019 for these projects. Similarly, funding commitments of $22.7 million made in the previous reporting period (Fiscal 2018) are not expected to have expenditures until after the Fiscal 2019 reporting period. As such, all of these expenditures will not be reported in this document and will be detailed in future GGRR reports.

In Fiscal 2019, as mentioned above, the government established the CleanBC Better Buildings program and BC Hydro delivers that program on behalf of the government. To complement the government's program, in Fiscal 2019, BC Hydro developed and advanced a new multi-year BC Hydro funded LCE program which was designed to reach customers and to enable opportunities not covered by GHG emissions reduction programs funded by the provincial government and/or federal government.[4] BC Hydro approved expenditures of $16.6 million for this multi-year program, focusing on opportunities in industrial process, transportation, and new construction. BC Hydro is currently working with government to determine if we should make adjustments to the multi-year BC Hydro LCE Program to support government initiatives being planned as part of CleanBC. As part of this multi-year program, in Fiscal 2019, BC Hydro undertook public awareness campaign activities

[4] This multi-year program may sometimes be referred to as "BC Hydro LCE Program" to distinguish it from the government-funded program.

which are defined as prescribed undertakings under section 4(3)(a) of the GGRR, and an LCE study (Wild Sight) which is defined as a prescribed undertaking under section 4(3)(c) of the GGRR. These undertakings are discussed in section 3.2 below.

3.2 Fiscal 2019 LCE Programs

The following provides details on individual projects and activities within the LCE Programs that incurred expenditures in Fiscal 2019.

(i) [redacted] (Project 3 in Table 2): This project is interconnected to BC Hydro transmission line [redacted] in Northeastern B.C. It is an undertaking within the class of prescribed undertakings set out in section 4(3)(a) of the GGRR. There are multiple project phases. The first phase achieved Facility Commercial Operation Date (**COD**)[5] in Fiscal 2019 pursuant to the terms of the LCE Incentive Agreement. Other project phases are expected to achieve Facility COD in subsequent fiscal years. The purpose of the supporting funds from BC Hydro is to assist [redacted] in the acquisition, installation, and use of equipment that will use BC Hydro's electricity instead of natural gas to power natural gas extraction, processing and production operations.

[redacted] (Project 4 in Table 2): BC Hydro also has an LCE Incentive Agreement for the [redacted] site. This project is interconnected to BC Hydro transmission line [redacted] in Northeastern B.C. There are two project phases. Similar to Project 3, this project is an undertaking within the class of prescribed undertakings set out in section 4(3)(a) of the GGRR. Project 4 was energized in Fiscal 2019, but has not yet achieved Facility COD in accordance with the LCE Incentive Agreement. Accordingly, no supporting funds were provided

[5] Under the Incentive Agreement, Facility COD is required before an incentive fund payment can be made to the customer.

to the customer in Fiscal 2019. For this reason, Table 2 recognizes Project 4, but does not include any incentive expenditure, energy, demand, or GHG emission reduction values. Results of both phases will be provided in future reports when incentive funding is paid to the customer.

(ii) Thompson Rivers University Project: This project was carried out at the customer site in Kamloops, B.C. The supporting funds were used by Thompson Rivers University in the acquisition, installation, and use of equipment that uses electric boilers in place of natural gas boilers in a new building. The Thompson Rivers University Project is an undertaking within the class of prescribed undertakings set out in section 4(3)(a) of the GGRR.

(iii) Copper Mountain Project: This is one of the studies carried out by the customer in Fiscal 2019. BC Hydro provided funding to enable the customer to complete research to compare two material waste handling options for its operations in Southern B.C. The status quo option of using diesel-fueled trucking was compared to options that would utilize electric conveying technology for waste haul. The objective of the study was to determine the economic value of pursuing the conveyor option beyond the conceptual stage. The study determined that there were no 'Life of Mine' economic advantages in electrification of the waste rock transportation by conveyor from the pit to the waste rock dump. This study scope did not include measuring the impact of utilizing electric conveying technology on ore haulage which may be investigated in a future study. The Copper Mountain Project is an undertaking within the class of prescribed undertakings set out in section 4(3)(c) of the GGRR.

(iv) Wild Sight Project (with support from Columbia Basin Trust): BC Hydro provided supporting funds for a study to examine the feasibility of conducting a truck stop electrification pilot project in the town of Golden in Southeastern B.C. Truck stop electrification (**TSE**) technology allows those in the long haul trucking industry the opportunity to connect to the electrical grid rather than idle their truck engines while stopped or 'overnighting'. Idle time reduction saves significant diesel fuel combustion, therefore avoiding CO_2 emissions. This study was part of the multi-year BC Hydro LCE Program discussed in section 3.1. Fiscal 2019 expenditures for this study are reflected in the BC Hydro LCE Program No. 2 line in Table 2. The Wild Sight project is an undertaking within the class of prescribed undertakings set out in section 4(3)(c) of the GGRR.

(v) Public Awareness Campaign: Also as part of the multi-year BC Hydro LCE Program, in Fiscal 2019, we implemented a public awareness campaign program to help make the concept of LCE, in particular with respect to owning and using an electric vehicle (**EV**), more tangible to our customers. Fiscal 2019 expenditures for this public awareness campaign are reflected in the BC Hydro LCE Program No. 1 line in Table 2. This included tools to help customers understand the cost of owning an EV in B.C. and displays and materials to support BC Hydro's community outreach team in educating customers on the EV as part of community and retail events. The public awareness campaign program is an undertaking within the class of prescribed undertakings set out in section 4(3)(a) of the GGRR.

Ratepayer impacts and estimated GHG emission reductions respecting these undertakings are shown in Table 2 below.

3.3 Methodology and Verification Methods

Depending on individual projects or programs within the LCE Programs, there can be up to four distinct activities that BC Hydro may use to review and verify estimates of incremental electrical load and emission reductions arising from electrification. These are: (i) technical review; (ii) site inspection; (iii) measurement and verification; and (iv) evaluation. Results from each area may be used in project or program management to ensure that BC Hydro receives the expected benefits. BC Hydro will be selective in the use of these processes, and focus its efforts where warranted to improve the accuracy of estimates and reduce exposure to risk. This approach mirrors BC Hydro's current approach to demand-side management electricity savings, and provides estimates for both additional electricity demand and greenhouse-gas emission reductions.

The GHG emission reduction estimates are developed as part of the technical review for each project or program application and may be adjusted based on the outcome of site inspections and the electricity demand findings resulting from the measurement and verification activities.

The methodology BC Hydro has used to estimate GHG emission reductions involves developing engineering estimates of the amount of carbon-based fuel that will be offset by electricity, and quantifying the associated GHG emission reductions using the 2017 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions. The calculation nets out the GHG emissions associated with BC Hydro's electricity, which are also quantified using the 2017 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions.

BC Hydro notes that this estimate may differ from actual GHG emission reductions as determined by the customer and which are specific to their unique electrification project(s). Where an actual value has been provided to BC Hydro by the customer, or reported by the customer to the government through an Industrial Emissions Report, BC Hydro will show the customer-reported value in Column H of Table 2.

BC Hydro may also conduct a technical review of baselines, calculations, and assumptions used to determine the GHG reductions in the Industrial Emissions Report. Any changes to the value reported in a previous reporting period will be reflected in the cumulative values in Column H (ii) of Table 2.

The methodology used for typical electrical energy impact calculations for LCE projects is as follows: The total annual energy consumption = facility baseline electricity consumption + incremental LCE electricity consumption +/- baseline energy adjustments. The total average monthly electrical demand = baseline average monthly electrical demand + incremental LCE average monthly electrical demand +/- baseline demand adjustments. Baseline adjustments are determined based on any net baseline energy consumption impacts that may be a result of the LCE project.

The two LCE projects (Project 3 and Thompson River University Project) completed in Fiscal 2019 have gone through a technical review and had a site specific measurement and verification plan for the estimated additional electricity consumption and demand. The plan was developed and included as part of the funding agreement between BC Hydro and the recipient. The respective methodology used for these two projects is as follows:

- Project 3: The measurement and verification approach applied to this project generally follows Option B, Retrofit Isolation: All Parameter Measurement, as set out in the International Performance Measurement & Verification Protocol (IPMVP) – Core Concepts October 2016 EVO 10000 – 1:2016; and
- Thompson Rivers University Project: The measurement and verification approach applied to this project generally follows Option D, Calibrated Simulation, as set out in the International Performance Measurement & Verification Protocol (IPMVP) - Core Concepts, October 2016 EVO 10000 - 1:2016.

3.4 Performance Metrics

BC Hydro outlines separately the different performance metrics used for the projects, studies, and public awareness campaigns described in section 3.2 above.

3.4.1 LCE Projects

For the two projects (Project 3 and the Thompson Rivers University project) completed in Fiscal 2019, using above mentioned methodologies for electricity consumption, demand and GHG emission reductions, BC Hydro will consider the following to verify project performance:

1. Project completion – has the project progressed as described in the application?;
2. Electrical energy consumption – did the project consume the amount of electrical energy as described in the LCE Agreement?; and
3. GHG emission reduction – was fossil fuel consumption replaced with BC Hydro electricity? Was an associated GHG emission reduction realized?

Measurement and verification activities for the projects are underway.

3.4.2 LCE Studies

As discussed in section 3.2 above, BC Hydro provided funding to support two studies, the Copper Mountain project and the Wild Sight project. BC Hydro supported studies are critical in enabling customers to build the business case for project implementation as well as providing key inputs on barriers, costs, and benefits into program development and design.

Performance metrics for LCE studies consider whether the study/project may yield the following information, such as

1. information which could inform and improve accuracy of the project modeling assumptions;
2. information which could inform and improve understanding of market barriers and customer drivers;
3. site specific investigation and engineering analysis at a level sufficient to determine if advancing the project would provide tangible benefits that would make business sense for the customer and BC Hydro to continue supporting the project; and

4. learnings that may inform future BC Hydro programs and customer opportunities.

The two studies completed in Fiscal 2019 met their performance metrics.

3.4.3 Public Awareness Campaign

For public awareness campaigns, BC Hydro may track the performance of awareness activities through measures such as:

- Reach measures that are volume-based and support building awareness through impressions (TV, out of home advertising, online), video views, and media pickups;
- Traction measures that are sentiment-based and support receptiveness such as favourability, likability, changes pre to post; and
- Action measures that drive participation through clicks, sessions, contest entries, social engagement, and customer intercepts at events or program participation.

3.5 Cost-Effectiveness

As required under section 4(4) of the GGRR, undertakings are in the class of undertakings prescribed by sections 4(3)(a) to 4(3)(b) of the GGRR only if they satisfy a cost-effectiveness test. That cost-effectiveness test is defined in section 4(1) of the GGRR and requires that each undertaking that is an undertaking within the class of undertakings prescribed by subsections 4(3)(a) or 4(3)(b) of the GGRR have a positive net present value (**NPV**), with the measure of a program's NPV being that of all of the programs that fall within the class of undertakings described in subsections 4(3)(a) and 4(3)(b) of the GGRR. The GGRR cost-effectiveness test is measured only at the time BC Hydro decides to carry out the program.

Table 2 shows the GGRR NPV of LCE projects/programs prescribed under section 4(3)(a) and 4(3)(b) of the GGRR. The total GGRR NPV of these undertakings is $134.7 million which includes actual and committed expenditures and benefits from past, current, and future reporting periods. The GGRR NPV indicates that these undertakings are cost-effective.

3.6 Results Table - Explanation of Terms

Table 1 includes a description of the information provided in Table 2 below with regard to the LCE Programs.

1 **Table 1 LCE Programs Results Table:**
2 **Explanation of Terms**

Column	Heading	Descriptions
A	GGRR	Applicable section of the GGRR
B	Project / Program/Contract / Expenditure	Low-carbon electrification activities to encourage or enable the use of electricity in place of other sources of energy that produce more greenhouse gas emissions.
$C_{(i)}$	Actual Expenditure ($ million)	Costs incurred at the end of the current reporting fiscal year
$C_{(ii)}$	Cumulative: Actual Expenditures ($ million)	The sum of successive costs incurred as at the end of the reporting fiscal year.
D	Cost Effectiveness ($ million): NPV to 2030 (Fiscal 2031)	The present value of the costs and benefits are determined using a discount rate equal to BC Hydro's weighted average cost of capital. The present value of the costs are subtracted from the present value of the benefits from the project start year to last year in the calculation period (Fiscal 2031) to determine the net present value for the project.
E	Cost Effectiveness ($ million): GGRR NPV to 2030 (Fiscal 2031)	The calculation of the GGRR NPV is based on costs and benefits as defined in the GGRR as of Fiscal 2018. Per that definition, benefits mean all revenues BC Hydro expects to earn as a result of implementing LCE programs falling under subsections 4(3)(a) or 4(3)(b), less revenues that would have been earned from the sale of that electricity to export markets. Costs mean all the costs BC Hydro expects to incur to implement LCE programs falling under subsections 4(3)(a) or 4(3)(b), including development and administration costs. For clarity, costs includes historic and future cost, committed expenditures and benefits from past, current and future reporting periods.
$F_{(i)}$	Actual: Additional Energy Consumption (MWh/year)	The average annual additional energy consumption estimated to be delivered from the project in the current reporting fiscal period.
$F_{(ii)}$	Cumulative: Additional Energy Consumption (MWh/year)	The sum of the successive average annual additional energy consumption estimated to be delivered from the project as at the end of the reporting fiscal period.
$G_{(i)}$	Actual: Additional Capacity Demand (MW)	The total energy demand added
$G_{(ii)}$	Cumulative: Additional Capacity Demand (MW)	Sum of the successive energy demand addition
$H_{(i)}$	Actual: Estimated GHG Emission Reductions (tonnes CO_2e/year)	The average annual tonnes per year of carbon dioxide equivalent reductions from the project in the current reporting fiscal period.
$H_{(ii)}$	Cumulative: Estimated GHG Emission Reductions (tonnes CO_2e/year)	The sum of the successive additional average annual tonnes per year of carbon dioxide equivalent reductions from the project as at the end of the reporting fiscal period.

3.7 Results Table

Table 2 summarizes information regarding the LCE Programs that are undertakings prescribed by sections 4(3)(a)(i), 4(3)(a)(ii), 4(3)(b)(i), 4(3)(b)(ii), 4(3)(c) and 4(3)(d) of the GGRR. The indications of "n/a" in Table 2 are due to: (1) the nature of the project, study or program, such that requested information cannot be obtained; or (2) the project, study, or program are prescribed by sections 4(3)(c) and 4(3)(d) of the GGRR and thus the cost-effectiveness test does not apply. BC Hydro provides as Attachment 3 an excel spreadsheet with annual expenditures, in total and by project/study/program, as outlined in the Reporting Requirements.

The GGRR Reporting Requirements also request graphical depictions (e.g., pie charts or bar charts) of the distribution by region in the Province and the distribution by customer sector where possible. Given that the Fiscal 2019 LCE Programs volume consisted of four completed projects, it was determined that a graphical depiction may not be meaningful and as such was not included in this report.

Table 2 LCE Programs Results for Year Ending March 31, 2019

	A	B	C		D	E	F		G		H	
	GGRR	**Project/Program/Contract/Expenditure**	**Expenditure ($ million)**		**Cost Effectiveness ($ million)**		**Additional Energy Consumption[2] (MWh/year)**		**Additional Demand (MW)**		**GHG Emission Reductions (tonnes CO_2e/year)**	
			Actual (i)	**Cumulative (ii)**	**NPV to 2030 (Fiscal 2031)**	**GGRR NPV to 2030 (Fiscal 2031)[1]**	**Actual (i)**	**Cumulative (ii)**	**Actual (i)**	**Cumulative (ii)**	**Actual (i)**	**Cumulative (ii)**
1	4(3)(c)	Vancouver Fraser Port Authority	0.00	0.07	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2	4(3)(c)	[redacted] (Project 1)[4]	0.00	0.01	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
3	4(3)(c)	[redacted] (Project 2)	0.00	0.01	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4	4(3)(c)	BC Hydro Program Staff Labour	0.00	0.12	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
5	4(3)(a)	[redacted] (Project 3)	6.35	6.35	64.3	64.3	104,244	104,244	14.0	14.0	62,329[3]	62,329
6	4(3)(a)	[redacted] (Project 4)	0.00	0.00	45.9	110.2	n/a	n/a	n/a	n/a	n/a	n/a
7	4(3)(a)	Thompson Rivers University	0.28	0.28	0.3	110.5	2,737	2,737	0.0	0.0	562	562
8	4(3)(c)	Copper Mountain Mine	0.07	0.07	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9	4(3)(c)	Translink	0.00	0.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10	4(3)(a)	BC Hydro LCE Program No.1	0.41	0.41	24.2	134.7	0	0	0.0	0.0	0	0
11	4(3)(c)	BC Hydro LCE Program No. 2	0.00	0.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
		Total	**7.11**	**7.32**	**134.7**	**134.7**	**106,981**	**106,981**	**14.0**	**14.0**	**62,891**	**62,891**

[1] Where a project/program has no actual or cumulative expenditures, but has an NPV, this means that the decision to go ahead with that project/program was made in this (or previous) reporting periods, but that the project/program is not expected to be implemented until a future year.

[2] Values reported in column F represent the 'run rate' or annualized rate of additional energy consumption.

[3] The GHG emission reductions shown are associated with the electrification of Project 3 and they represent estimates based on engineering calculations at the time BC Hydro made the decision to carry out offering incentive funding to the project. The GHG emission reductions associated with this project are also referenced in section 4 - LCE Infrastructure Projects of this report.

[4] Project 1 and 2 were described in the Fiscal 2018 Annual Report.

REDACTED in PUBLIC VERSION

4 LCE Infrastructure Projects

4.1 Overview

In this section 4, we describe the LCE Infrastructure Projects (i.e., being projects within the classes of undertaking prescribed by subsections 4(2) or 4(3)(e) of the GGRR) and available evaluation results.

Northeast British Columbia is forecasted to experience a significant increase in natural gas production and processing capacity, primarily in the Montney region. In the absence of adequate electricity supply, much of this development will be powered by natural-gas fired production processes. Meanwhile, BC Hydro's transmission system in this region is constrained. Further, the transmission system's ability to supply new loads in the South Peace region at all, even with a reduced level of reliability, is expected to be exceeded in summer 2021. Accordingly, BC Hydro will construct and operate new transmission and distribution facilities, and/or provide for [redacted] generation until such system upgrades are completed. These LCE Infrastructure Projects will enable the provision of reliable electricity service as a power supply alternative to carbon-based fuels. This will enable the reduction of existing GHG emissions or avoidance of future incremental GHG emissions.

4.2 Fiscal 2019 LCE Infrastructure Projects

In Fiscal 2019, BC Hydro incurred expenditures of $50.0 million in regard to two LCE Infrastructure Projects. Expenditures incurred and recorded in future fiscal years will be described in the applicable future GGRR annual report.

4.2.1 Peace Region Electricity Supply (PRES) Project

The PRES Project was introduced in Fiscal 2018 GGRR Annual Report. As explained in the Fiscal 2018 report, the PRES Project will enable natural gas producers and processors to electrify their existing and new operations, rather than self-supplying with natural gas. This includes natural gas producers and processors as defined in GGRR paragraphs 4(2)(a)(i) and (ii). The PRES Project is expected to reduce GHG emissions in B.C. from any existing plant or from any prospective new plant that elects to take supply from BC Hydro rather than self-supply using natural gas.

The PRES Project was approved by BC Hydro's Board of Directors for implementation in June 2018. When BC Hydro's Board of Directors approved the PRES project, BC Hydro reasonably expected that the PRES project would have an in-service date no later than December 31, 2022. As of this report, the PRES Project has an expected in-service date of October 31, 2021. Therefore, the PRES Project is a prescribed undertaking pursuant to GGRR section 4(2).

The PRES Project is currently in the Implementation Phase and has an estimated total capital cost of $285 million. As of the end of Fiscal 2019, BC Hydro has incurred $69.9 million in total capital expenditures on developing the PRES Project, of which $48.4 million was incurred in Fiscal 2019.

During Fiscal 2019, BC Hydro made progress on the detailed design work for the PRES Project, and started material and equipment procurement. BC Hydro also secured the required licences and permits to be able to advance the PRES Project to the construction stage, started clearing and access road construction for the new transmission line right-of-way, and have started construction work.

BC Hydro will report on performance metrics and environmental benefits of undertaking the PRES Project when it is in-service, and existing and new natural gas producing or processing plant operations are connected to the BC Hydro's system.

4.2.2 [redacted] Generation Agreement

As reported in the Fiscal 2018 GGRR Annual Report, BC Hydro entered into a Generation Agreement with [redacted] to provide [redacted] generation as a [redacted] mechanism until the PRES Project is in service.

During periods of actual or anticipated system constraint, under the Generation Agreement, BC Hydro has the right to direct [redacted] to [redacted] its facilities in Northeast B.C. ([redacted] and [redacted]) from the grid and self-supply with electricity produced by [redacted] on-site generating units. BC Hydro treats [redacted] generation as a system resource, such that any self-generated electricity temporarily replaces electricity that would otherwise be provided from the BC Hydro transmission system. The Generation Agreement achieves the purpose of providing reliable electricity supply to electrified[redacted] facilities during events of system constraint until the PRES Project comes into service.

The total forecast nominal value of the Agreement is $12.0 million. Total expenditures incurred in Fiscal 2019 with respect to this [redacted] agreement are $1.6 million.[6]

4.3 Quantitative Data – Methodology & Assumptions

BC Hydro has developed criteria to qualify customer loads for inclusion in its estimates for GHG emissions reduced or avoided due to the PRES Project.

For the customer load to be included:

- Must be a new natural gas processing plant (including associated gas gathering and wellpad facilities) or existing plant converting to take grid service which

[6] An additional expenditure of $0.3 million was incurred for [redacted] generation dispatched as an energy resource over 11 days in March 2019. BC Hydro does not consider the associated dispatch costs to be reportable GGRR costs because they were incurred for a purpose ancillary to proving reliable network service.

takes, or commits to take, electricity service from BC Hydro in Fiscal 2018 or later;

- Would have used natural gas for power supply in the absence of BC Hydro's commitment to construct and operate new facilities; and
- Will be served by the PRES Project once it is placed in service.

These criteria thus include: (i) existing "brownfield" loads which fuel-switch from carbon-based fuel to grid electricity; and (ii) new "greenfield" loads that make the investment decision to take grid electricity as an alternative to carbon-based fuels for power supply.

BC Hydro notes that these criteria differ from the current British Columbia Greenhouse Gas Offset Protocol (*Fuel Switch Version 1.0, dated August 16, 2018*) which is specific to the replacement of existing gas-powered turbines with electrical grid power. Under the current protocol, GHG emission reductions would only arise where an existing customer facility fuel switches from a carbon-based fuel (such as natural gas) to low-carbon grid electricity and would not apply to any new plant that elects to be served with grid electricity in the first instance.

4.4 Performance Metrics

The GGRR performance metrics for the PRES Project are listed in Table 3 below.

Table 3 PRES Project: GGRR Performance Metrics

Type of Facility	Project(s)	Performance Metrics
Transmission & Distribution	PRES Project	1. New load served 2. GHG emissions reduction
[redacted] Generation	[redacted] Generation Agreement	3. New load served 4. GHG emissions reduction

A key purpose of the PRES Project is to provide a clean, reliable source of electrical power supply to existing and new natural gas processing operations. In the absence of the PRES Project, there would be no grid service alternative. These plant operations would otherwise need to use natural gas (or other fossil fuels) for power supply. Since greenhouse gases are emitted when fossil fuels are burned to create power, the PRES Project will reduce GHG emissions in British Columbia for any existing plant that elects to take grid service rather than self-supply using natural gas.

GHG Emission Reduction Methodology

BC Hydro will estimate the impact the PRES Project will have on GHG emission reductions in British Columbia based on the assumptions and methodology set out in section 3.3 of this report. BC Hydro will apply these same assumptions and methodology to estimate the impact that temporary generation will have on GHG emission reductions in British Columbia until the PRES Project is in-service. For Fiscal 2019, the GHG emissions intensity factors determined in accordance with this methodology are listed below for convenience:

- Average emissions intensity factor for natural gas turbine: [redacted].[7]
- Less emissions intensity factor for BC Hydro grid electricity: [redacted].[8]
- Net emissions intensity factor for electrified loads: [redacted].

Determination of Eligible Loads for GHG Emission Reduction

In Fiscal 2019, certain [redacted] facilities were electrified pursuant to the support provided through the Generation Agreement (to ensure reliable electricity supply) and the Incentive Agreement (to provide supporting funds for investment in electrical infrastructure) described in the previous sections. Absent these agreements,

---

7 The efficiency assumption of 29.5 per cent for gas turbines was developed by calculating the weighted average efficiency from metered data of two customer operated gas turbine electrical generation units.

8 *Source: British Columbia Government: 2017 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions, page 17.*

BC Hydro considers that the [redacted] loads would not have connected to the BC Hydro transmission system and taken grid service.

As discussed in section 3.2 above, [redacted] has two sites which are relevant to the prescribed undertakings, the [redacted] site and the [redacted] Site.

The [redacted] site was energized from the BC Hydro transmission system in April 2018. This site comprises three discrete load centres: two gas processing plants and one field/gathering system. The load from one of the gas plants is not eligible for GHG emission calculation because it was previously served from the BC Hydro distribution system. The other gas plant load and field/gathering system loads were new loads to the BC Hydro system in Fiscal 2019. For Fiscal 2019, total new load served by BC Hydro was 90,958 MWh, with an estimated GHG emission reduction of 54,393 tonnes CO_2e.

[redacted]

The [redacted] site was energized from the BC Hydro transmission system in September 2018. This site comprises two gas processing plants, one of which was operational in Fiscal 2019 while the other was under construction. For Fiscal 2019, total new load served by BC Hydro was 39,163 MWh, with an estimated GHG emission reduction of 23,420 tonnes CO_2e.

[redacted]

BC Hydro notes that for each site, electrical energy consumption arising from the electrification of new loads is used to determine associated GHG emission reductions pursuant to the methodology described in section 3.3. These values have been incorporated into Table 5.

4.5 Results Table - Explanation of Terms

Table 4 includes a description of the information provided in the results table for LCE Infrastructure Projects. The reason for the indications of "n/a's" is due to the nature of the PRES Project as of March 31, 2019, as described above.

Table 4 LCE Infrastructure Projects Results Table: Explanation of Terms

Column	Heading	Descriptions
A	Prescribed Undertaking	Type of prescribed undertaking.
B	Name	Project, program, or customer name.
C (i)	Actual ($ million)	Actual costs in millions incurred at the end of the current reporting fiscal.
C (ii)	Cumulative Costs ($ million)	Cumulative actual costs in millions incurred from first year of expenditure to the end of the current reporting fiscal.
C (iii)	Forecast Total ($ million)	Approved Anticipated Total Capital Cost of Project
D	Capacity of Facility (MW)	Planned facility capacity in megawatts at N-1 and N-0.
E	Total Capacity Committed/Secured (MW)	Cumulative total capacity committed and secured until the end of the current fiscal year in megawatts.
F	Total Customer Load(s) Served (MW)	Cumulative total customer loads served as at the end of the current fiscal year in megawatts.
G	Total Energy Provided to Customers (MW/h)	Cumulative total energy provided to customers as at the end of the current fiscal year in megawatts per hour.
H (i)	Actual: GHG Emissions Reduction Estimates (tonnes CO_2e/year)	Actual GHG Emissions Reduction at the end of the current fiscal period in tonnes of carbon dioxide equivalent per year.
H (ii)	Cumulative: GHG Emissions Reduction Estimates (tonnes CO_2e/year)	Cumulative GHG Emissions Reduction as at the end of the current fiscal period in tonnes of carbon dioxide equivalent per year.
I (i)	Type: Fossil Fuel(s) Avoided Or Displaced	Type of fossil fuels avoided or displaced or likely to be avoided or displaced.
I (ii)	Amount: Fossil Fuel(s) Avoided Or Displaced	Amount of fossil fuels avoided or displaced or likely to be avoided or displaced.

4.6 Results Table

Table 5 provides the results for LCE Infrastructure Projects with expenditures in Fiscal 2019.

Table 5 LCE Infrastructure Projects Results for Year Ending March 31, 2019

	A	B	C			D	E	F	G	H		I	
	Prescribed Undertaking	**Name**	**Cost**			**Capacity of Facility (MW)**	**Total Capacity Committed/ Secured (MW)**	**Total Customer Load(s) Served (MW)**	**Total Energy[1] Provided to Customers (MW/h)**	**GHG Emissions Reduction Estimates[2] (tonnes CO_2e/ year)**		**Fossil Fuel(s) Avoided or Displaced**	
			Actual ($ million) (i)	**Cumulative ($ million) (ii)**	**Forecast Total ($ million) (iii)**					**Actual (i)**	**Cumulative (ii)**	**Type (i)**	**Amount (ii)**
1	T&D	PRES Project	48.4	69.9	285	800 - 950	24	n/a	n/a	n/a	n/a	n/a	n/a
2	[redacted] Generation	[redacted]	1.6	1.6	12	24	24	26	130,121	77,812	77,812	n/a	n/a

[1] Reflects total new facility load served from the BC Hydro transmission system in F2019. 118,252 MWh of load is from existing brownfield facilities that fuel-switched to grid power. 11,869 MWh of load is from new greenfield facilities that electrified.
[2] The GHG Emissions Reduction Estimates are specific to eligible [redacted] and [redacted] plant loads that were served by BC Hydro in Fiscal 2019 in place of natural gas-fired supply.

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REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

18.0 D. PRESCRIBED UNDERTAKINGS UNDER THE CLEAN ENERGY ACT AND GREENHOUSE GAS REDUCTION (CLEAN ENERGY) REGULATION

Reference: CHAPTER 10 – DEMAND SIDE MANAGEMENT
Exhibit B-1, Appendix Y, pp. 3, 8, 10–11; Exhibit B-1, Appendix BB, pp. 1–4, 10, 16 Prescribed undertakings

Page 3 of Appendix Y to BC Hydro's Application states:

> **…** the Low Carbon Electrification (LCE) Demand-Side Management (DSM) Projects/Programs that we have undertaken and plan to undertake over fiscal 2019, fiscal 2020 and fiscal 2021. All of our LCE DSM Projects/Programs are within one or more class of undertakings prescribed under the Greenhouse Gas Reduction (Clean Energy) Regulation, issued under section 18 of the Clean Energy Act.

Table 2-1 on page 8 of Appendix Y outlines BC Hydro's expenditures for the Initial LCE Projects for 2018 - 2022, at a total cost of $29.71M.

Table 3-2 on page 11 of Appendix Y outlines BC Hydro Funded Low Carbon Electrification Program Expenditures for 2018 – 2022, at a total cost of $16.65M.

Pages 1–4 of Appendix BB, Attachment 2 - Fiscal 2018 Annual Report No. 1 state:

> The GGRR Reporting Requirements also requests a report by a Fairness Advisor on the competitiveness of any call process held during the reporting period. BC Hydro confirms that in Fiscal 2018 it did not hold any call processes in regard to its LCE DSM Project/Programs or its LCE Infrastructure Projects.

Table 2 in Appendix BB sets out Electrification Information for LCE DSM Projects/Programs for Year Ending March 31, 2018 and shows the actual cost at $0.22M. Table 5 in Appendix BB sets out the LCE Infrastructure Projects Results as of March 31, 2018.

2.18.1 Has BC Hydro prepared a Fiscal 2019 GGRR Annual Report?

2.18.1.1 If so, please provide a copy of this report.

RESPONSE:

A copy of the report is provided as Attachment 1 to BC Hydro's response to BCUC Panel IR 2.18.1.

18.0 D. PRESCRIBED UNDERTAKINGS UNDER THE CLEAN ENERGY ACT AND GREENHOUSE GAS REDUCTION (CLEAN ENERGY) REGULATION

Reference: CHAPTER 10 – DEMAND SIDE MANAGEMENT
Exhibit B-1, Appendix Y, pp. 3, 8, 10–11; Exhibit B-1, Appendix BB, pp. 1–4, 10, 16 Prescribed undertakings

Page 3 of Appendix Y to BC Hydro's Application states:

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Pages 1–4 of Appendix BB, Attachment 2 - Fiscal 2018 Annual Report No. 1 state:

> The GGRR Reporting Requirements also requests a report by a Fairness Advisor on the competitiveness of any call process held during the reporting period. BC Hydro confirms that in Fiscal 2018 it did not hold any call processes in regard to its LCE DSM Project/Programs or its LCE Infrastructure Projects.

Table 2 in Appendix BB sets out Electrification Information for LCE DSM Projects/Programs for Year Ending March 31, 2018 and shows the actual cost at $0.22M. Table 5 in Appendix BB sets out the LCE Infrastructure Projects Results as of March 31, 2018.

2.18.2 Is the list, description and cost of prescribed undertakings outlined at Appendices Y and BB still accurate and up to date?

RESPONSE:

This response (including Attachment 1 to this response) contains confidential customer-specific information which has been redacted. An un-redacted version is being made available to the BCUC only.

The prescribed undertakings outlined in Appendix Y and BB have been updated.

The Fiscal 2019 Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) annual report is provided as Attachment 1 to BC Hydro's response to BCUC Panel IR 2.18.1, and is the most recent GGRR annual report.

An update to Appendix Y is provided as Attachment 1 to this response, which reflects the most up to date information on Low Carbon Electrification Demand-Side Management Projects/Programs.

There have been no changes to the list or description of LCE infrastructure projects (i.e., projects undertaken under section 4(2) or section 4(3)(e) of the GGRR) since the Fiscal 2019 GGRR annual report. An update of actual expenditures to December 31, 2019 for the LCE infrastructure projects is provided below.

Prescribed Undertaking	Name	Cost ($ million)			
		Actual (F19)	Actual (April to December 2019)	Cumulative to December 31, 2019	Forecast Total
T&D	PRES Project	48.4	64.8	130.6	285
Temporary Generation	[redacted]	1.63	1.64	3.27	12

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LOW CARBON ELECTRIFICATION PROGRAM

Conservation and Energy Management

Updated in ~~February~~ December 2019

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Contents

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1.0 Overview

This appendix was first completed in February 2019 (**February 2019 Report**) and was updated in December 2019 (**December 2019 Updates**) to reflect progress or changes in programs/projects described in the February 2019 Report. The December 2019 Updates are black-lined for ease of reference.

In this appendix, we describe the Low Carbon Electrification (**LCE**) Demand-Side Management (**DSM**) Projects/Programs that we have undertaken and plan to undertake over fiscal 2019, fiscal 2020 and fiscal 2021. All of our LCE DSM Projects/Programs are within one or more class of undertakings prescribed under the Greenhouse Gas Reduction (Clean Energy) Regulation, issued under section 18 of the *Clean Energy Act*.

1.1 Greenhouse Gas Reduction Regulation

Section 18 of the *Clean Energy Act* requires the British Columbia Utilities Commission (the BCUC) to allow BC Hydro to collect sufficient revenue to recover costs incurred for prescribed undertakings. Section 4 of the Greenhouse Gas Reduction (Clean Energy) Regulation (B.C. Reg. 102/2012) (**GGRR**) defines eight classes of electrification prescribed undertakings corresponding to sections 4(2), 4(3)(a)(i), 4(3)(a)(ii), 4(3)(b)(i), 4(3)b)(ii), 4(3)(c), 4(3)(d) and 4(3)(e). Undertakings are in a class of undertakings defined in subsections 4(3)(a) to 4(3)(b) of the GGRR if they satisfy a cost-effectiveness test defined in subsection 4(1) of the GGRR.

The eight new classes of electrification undertakings prescribed by section 4 of the GGRR can be divided into two broad categories: those that are program based, similar to BC Hydro's demand-side management programs,[1] and those that are infrastructure based.[2] BC Hydro refers to its undertakings that fall within one of the classes in the former category as Low Carbon Electrification (**LCE**) Demand-Side Management (**DSM**) Projects/Programs, and to its undertakings that fall within one of the classes in the latter category as LCE Infrastructure Projects.

1 Being the classes of undertaking prescribed by subsections 4(3)(a)(i); 4(3)(a)(ii); 4(3)(b)(i); 4(3)(b)(ii); 4(3)(c) and 4(3)(d) of the GGRR.

2 Being the classes of undertaking prescribed by subsections 4(2) and 4(3)(e) of the GGRR.

1.2 Scope of Appendix Y

Appendix Y focuses only on LCE DSM Projects/Programs BC Hydro has undertaken, or will undertake, that are in one or more classes of undertakings defined in sections 4(3)(a), 4(3)(b), 4(3)(c), and 4(3)(d) of the GGRR.

Since the February 2019 Report~~Previous Application~~, there have been three major ~~a number of~~ developments on LCE DSM Projects/Programs, as outlined below:~~.~~

- In June~~ly~~ 2019~~8~~, BC Hydro submitted its Fiscal 2019~~8~~ Greenhouse Gas Reduction Regulation Annual Report (**Fiscal 2019~~8~~ Annual Report**). This report~~, a copy of which is~~ provided updates on the prescribed undertakings with expenditures incurred in fiscal 2019.

- In fiscal 2020, the Government of B.C. working in co-ordination with BC Hydro made a decision to direct a portion of CleanBC funding to support the design and construction of new high-performance buildings that use high-efficiency electricity in place of fossil fuels in order to reduce greenhouse gas (GHG) emissions. The Government funded program, branded under CleanBC Better Buildings, is being delivered by BC Hydro on Government's behalf. The introduction of the CleanBC funding prompted BC Hydro to re-consider the funding originally included within the BC Hydro Funded Low Carbon Electrification Program. BC Hydro was able to apply funds originally intended to support energy management study and implementation for new construction opportunities to support additional energy management study and implementation opportunities with industrial and large commercial customers.

- Also in fiscal 2020, BC Hydro continued public awareness efforts with respect to owning and using electric vehicles in B.C.. Working in co-ordination with Government, a rebate program for consumer electric vehicle chargers was launched. The program was established to align with existing Government incentive programs, targeting customers looking to charge their electric vehicle at home, or at their workplace.~~as Appendix BB.~~

In section 2.0 below, BC Hydro provides further details on LCE DSM Projects/Programs which were ~~previously~~ first introduced in the Fiscal 2018 Annual Report, later updated in the Fiscal 2019 Annual Report, and are in one or more class of undertakings defined in sections 4(3)(a) and 4(3)(c) of the GGRR. For the purpose of this document, these programs are referred to as "LCE Initial Projects". For this update, the ~~Section 2.0 also provides~~ past and forecast expenditures for these projects provided in section 2.0 were updated where applicable.

In section 3.0 BC Hydro provides details on ~~a new~~the LCE DSM Projects/Program, which w~~h~~as introduced in fiscal 2019. ~~been developed following the Fiscal 2018 Annual Report.~~ For the purpose of this document, this ~~new~~ program is referred to as the "BC Hydro LCE Program". Section 3.0 also provides expenditures for components of the program, including forecast expenditures for the test period.

In section 4.0 BC Hydro will demonstrate the cost-effectiveness of its LCE DSM Projects/Programs that are in the classes of undertakings defined under section 4(3)(a) and 4(3)(b) of the GGRR.

1.3 Overview of LCE DSM Projects/Programs

Beginning in fiscal 2018, BC Hydro moved forward with the Initial LCE Projects to assess and support immediate low carbon electrification opportunities among our customers. These projects are within one (or more) class of undertakings defined in subsections 4(3)(a) and 4(3)(c). These Initial LCE Projects also

- helped us gain a greater understanding of the technology, market, and barriers that customers and BC Hydro would face when developing low carbon electrification options; and
- provided BC Hydro the ability to act early and capture time-sensitive opportunities that could help inform the development of a broader low carbon electrification plan.

The Initial LCE Projects were introduced in the Fiscal 2018 Annual Report. Those included projects where BC Hydro incurred and recorded actual costs in fiscal 2018. Also included in the Fiscal 2018 Annual Report was a forecast of expenditures related to other projects where BC Hydro made preliminary funding commitments but there were no actual costs for those projects in fiscal 2018. The Fiscal 2019 Annual Report provides an update on the status and outcomes of projects introduced in the Fiscal 2018 Annual Report, section 3.2 (located on page 10 of 22 in RRA Appendix BB). In section 2.0 and Table 2-1 and Table 4-1, BC Hydro provides further information on the Initial LCE Projects where BC Hydro will expect to incur expenditures in fiscal 2019 and beyond.

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In early fiscal 2019, Government launched the EfficiencyBC retrofit programs (which are now branded as CleanBC Better Homes for residential programs and CleanBC Better Buildings for commercial buildings) to reduce greenhouse gas emissions in the province. This $24 million, Government funded program provides financial incentives to help households and businesses save energy and reduce greenhouse gas emissions by switching to high-efficiency heating equipment and making building-envelope improvements. BC Hydro is delivering the fuel switching component of the ~~EfficiencyBC~~ CleanBC programs on Government's behalf, within our service territory. This component helps customers switch from fossil fuels to our clean electricity. The expenditures associated with implementing the ~~EfficiencyBC~~ CleanBC programs are borne by Government and not BC Hydro ratepayers.

Coinciding with delivering the fuel switching component of the ~~EfficiencyBC~~ CleanBC retrofit programs and further to the Initial LCE Projects, BC Hydro ~~has~~ developed the BC Hydro LCE Program, a new BC Hydro funded low carbon electrification program. The program ~~has been~~was co-ordinated to align with, and not overlap with, ~~G~~government funded greenhouse gas emissions reduction programs. Specifically, the BC Hydro LCE Program was developed to reach customers not addressed by EfficiencyBC or by Government funded transportation programs.

In fiscal 2020, Government launched their CleanBC Commercial New Construction Program. The program provides funding for the design and construction of new high-performance buildings that use high-efficiency electricity instead of fossil fuels, in order to reduce greenhouse gas (GHG) emissions. BC Hydro is now delivering the fuel switching component of this Government funded program.

The BC Hydro LCE Program is described in section 3.0 and Table 3-1. The BC Hydro LCE Program has components that are within one or more class of undertakings defined by subsections 4(3)(a), 4(3)(b), 4(3)(c), and 4(3)(d) of the GGRR. As shown in Table 4-1 below, the undertakings in the classes defined in section 4(3)(a) and 4(3)(b) of the GGRR are cost-effective.

Should Government bring forward additional programs in the future that would overlap with activities planned or underway with funding from BC Hydro, we can make adjustments to our plans to ensure that any overlap is needed and by design.

BC Hydro expects to develop a future plan for low carbon electrification that is informed by the learning gained through the Initial LCE Projects and the BC Hydro LCE Program as well as Government's CleanBC Plan.

2.0 BC Hydro Funded Initial Low Carbon Electrification Projects

The Initial LCE Projects are in one or more class of undertakings defined in subsections 4(3)(a) and 4(3)(c). The details of these Initial LCE Projects are ~~provided~~ updated below.

Programs Under Subsection 4(3)(a)

- Customer Project 1 [redacted] and Project 2 [redacted] – [redacted] BC Hydro provided funds to [redacted] to assist in the acquisition, installation, and use of equipment that uses electricity to power natural gas production, instead of the customer burning their own gas to power gathering, transport and processing operations. Customer Project 1 has multiple phases, with the first phase achieving Facility Commercial Operation Date (COD) in fiscal 2019. The other phases of Project 1 are expected to achieve Facility COD in subsequent fiscal years. Customer Project 2 has two project phases and not yet achieved Facility COD. Table 2-1 shows forecast of expenditure reflecting the current estimated Facility COD dates for these two projects.
- Customer Project 3 – Thompson Rivers University: BC Hydro provided funding to Thompson Rivers University to assist in the acquisition, installation, and use of equipment that uses electricity (electric boilers) instead of natural gas boilers in a new building. This project is now completed.

Projects/Programs/Expenditures under subsection 4(3)(c)

In general, the projects/programs/expenditures within a class of undertakings defined in this subsection are for researching new applications of technologies that have not been proven in or adopted in BC, or are projects with specific customers researching technology applications where the learnings from the projects will inform future BC Hydro programs and customer opportunities.

- Project 4 - [redacted] The focus of this project was to examine a portion of the customer's industrial process heating requirements and technology alternatives with the intent of determining if a viable fuel switching technology solution may exist specific for the customer. Process heating is typically supplied by natural gas, or propane. This work investigated if an opportunity existed to use electricity in place of fossil fuels for [redacted] and also potentially for other BC Hydro customers. The study is now completed. Further detailed engineering and pilot testing would be required to determine specific sizing, cost, and performance suitability for the identified electric technology option. The decision to proceed with further investigation is currently with the customer.

- Project 5 - [redacted] The focus of this project was to enable the customer to have research completed by comparing two material handling options. The status quo option of using diesel fueled trucking was compared to options that would utilize electric conveying technology. The objective of the research was to determine whether the conveyor option is worth pursuing beyond the conceptual stage. The study is now completed and provided useful information regarding operational considerations and feasibility of utilizing electric conveyors. However, it determined that there were ~~currently~~no economic advantages in electrification of the material handling options studied.
- Project 6 - [redacted] The focus of this project was to examine technology alternatives for the customer to use electricity for [redacted] materials handling. The current materials handling method [redacted] involves use of diesel fueled equipment to remove the [redacted] from the [redacted] and [redacted] trucks (diesel fueled) to transport the [redacted] back into the [redacted] The project examined a potential electrified system [redacted]. The pre-feasibility study is now completed and found that a reduction in carbon dioxide equivalent (CO_2e) could be made. Based on the findings, the study report recommended proceeding with a detailed feasibility study to further develop the concepts and establish a preliminary design and corresponding capital cost estimate. The customer implemented alternative measures within their operations to reduce diesel use and corresponding CO_2e emissions. The measures implemented achieved CO_2e reductions comparable to the electrified system and the project is longer being pursued.
- Project 7 - Translink: Translink, along with the Centre for Urban Transit Research Innovation Consortium and BC Hydro, is conducting a pilot project which replaces four diesel buses with four electric-battery buses and two charging stations. The two year pilot project will evaluate the feasibility of technology using electric battery buses and charging stations on a broader basis. The pilot project is currently underway.

- Project 8 - Vancouver Fraser Port Authority (VFPA): This project focused on low carbon drayage and was the first phase of research into ways low carbon technologies could be introduced into the local heavy duty transportation network to reduce carbon emissions. Drayage referrers to transporting goods a short distance via ground freight. This study is now completed and has helped VFPA explore a range of trucking alternatives against the status quo baseline of a conventional diesel truck. The drayage network is large (over 1800 trucks) and complex. A large-scale implementation of new truck technologies within this network will be difficult and will involve stakeholder consultation. The VFPA is incorporating the information developed in this project into their broader efforts to support reductions in port-related air emissions that can affect air quality and contribute to climate change.
- Project 9 - Integral Group Consulting: This research project is completed. It consists of 6 individual buildings selected to represent a sampling of various building types, building code requirements, technologies, and studies the low carbon electrification opportunities that we may see come forward as implementation projects in these building types. The information gained from this project was used by BC Hydro and Government to inform the development of the CleanBC Better Buildings program.
- Project 10 - Thompson Rivers University: The focus of this project is to research the potential of a five-Year “building by building” retrofit approach, considering a number of technologies that could lead to a new strategy to electrify building systems instead of using other sources of energy that produce more greenhouse gas emissions. This study is underway and forecast to be completed in fiscal 2020.
- Project 11 - Wildsight, with support from Columbia Basin Trust – This project is examining the feasibility of conducting a truck stop electrification pilot project in the Golden area. Truck stop electrification (**TSE**) technology allows those in the long haul trucking industry the opportunity to connect to the electrical grid rather than idling their truck engines while stopped or overnighting. Idle reduction saves significant diesel fuel combustion avoiding CO2 emissions. This project is underway and forecast to be completed in fiscal 2020.

Table 2-1 below outlines BC Hydro's expenditures for the Initial LCE Projects in each fiscal year, including the test period. The updates to expenditures for Project 1, 2, 7 reflect revised project implementation forecasts provided by the customers.

Table 2-1 – Expenditures for Initial LCE Projects

Initial LCE Projects		**Expenditures ($ million)** [3]					
GGRR Regulation Subsection	**Project**	**2018 (Actuals)**	**2019 (Actuals)**	**2020 (Forecast)**	**2021 (Forecast)**	**2022 (Forecast)**	**Total**
4(3)(a)	Project 1	-	6.35~~0~~	1.58	~~2.70~~ 1.13	6.00	15.06~~0~~
	Project 2	-	-	~~13.50~~ 11.25	2.25	-	13.50
	Project 3	-	0.28	-	-	-	0.28
4(3)(c)	Project 4	0.01	-	-	-	-	0.01
	Project 5	-	0.07	-	-	-	0.07
	Project 6	0.00	-	-	-	-	0.00
	Project 7	-	~~0.50~~	0.50	-	-	0.50
	Project 8	0.07	-	-	-	-	0.07
	Project 9	-	0.09	-	-	-	0.09
	Project 10	-	0.06	-	-	-	0.06
	Project 11	-	0.00	-	-	-	0.00
	BC Hydro Program Staff Labour	0.12	-	-	-	-	0.12
Project Total		**0.21**	**~~7.30~~ 6.85**	**~~13.50~~ 13.33**	**~~2.70~~ 3.38**	**6.00**	**~~29.71~~ 29.76**

[3] Expenditure shown in Table 2-1 includes costs recorded in fiscal 2018, fiscal 2019 and fiscal 2020 (up to December 31st, 2019) as well as expenditures forecast for projects which BC Hydro has made preliminary funding commitments.

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3.0 BC Hydro LCE Program

The BC Hydro LCE Program, commenced in fiscal 2019, was developed to focus~~es~~ on opportunities in industrial process, transportation, and new construction, and include components in one (or more) class of undertakings defined in subsections 4(3)(a), 4(3)(b), 4(3)(c), and 4(3)(d). During initial development of the Program, BC Hydro had anticipated some funding to support energy study and implementation of low carbon electrification opportunities in new commercial construction. With Government now funding these opportunities through CleanBC we anticipate BC Hydro funding to allow for additional large commercial and industrial energy study and implementation opportunities.

A component of the BC Hydro LCE Program may be developed to focus on, for instance,

- Providing funds to enable energy management and audit services to our customers or educating and training customers regarding their energy use;
- Carrying out public awareness campaigns respecting energy use;
- Providing financial support to customers to assist them with the acquisition, installation and use of equipment that uses or affects the use of electricity;
- Providing funding to conduct research and pilot projects respecting technology that may enable our customers to use electricity; and
- Supporting standards making bodies in their development of standards respecting technologies that use electricity instead of other sources of energy.

The following Table 3-1 provides a high level overview of the components of the BC Hydro LCE Program and the relevant subsections of the GGRRs.

Table 3-1 –Component Description of the BC Hydro LCE Program

Components	Detailed Description	GGRR Subsection
Energy Management Studies and Incentives	Studies and Assessments – BC Hydro provides funding toward studies and assessments to assist customers, or those who may become customers, to identify and develop project opportunities involving the acquisition, installation, or use of equipment that uses electricity instead of other sources of energy that produce more greenhouse gas emissions. Project Incentives - BC Hydro provides project incentive funding to reduce the cost of projects to assist customers, or those who may become customers, with the acquisition, installation, or use of equipment that uses electricity instead of other sources of energy that produce more greenhouse gas emissions. Funding is provided direct to customers or in some cases direct to persons who -design, manufacture, sell, install or in the course of operating a business, provide advice respecting equipment that uses or affects the use of electricity, -or design, construct, manage or, in the course of operating a business, provide advice respecting energy systems in building or facilities, -or design, construct or manage district energy systems.	4(3)(a), 4(3)(b)
Public Awareness Campaigns	BC Hydro carries out a set of activities that educate and increase public awareness respecting the use of electricity instead of other sources of energy that produce greenhouse gas emissions. These activities cover a variety of channels and leverage specific partners such as retailers and manufacturers who have existing channels available to them that, when combined with BC Hydro's support, can reach a wide cross-section of relevant customers	4(3)(a), 4(3)(b)
Research and Pilots	BC Hydro works with customers and provides funding toward the research and development of technology, or pilot projects, that may enable the customers to use electricity instead of other sources of energy that produce more greenhouse gas emissions.	4(3)(c)
Standards Enabler	BC Hydro works with standards making bodies such as various levels of government, who are responsible for land use, building codes, product and equipment standards, policies, bylaws, and community plans, to advance standards for technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions, or technologies that affect the use of electricity by other technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions.	4(3)(d)

Components	Detailed Description	GGRR Subsection
Education & Training	BC Hydro delivers education and training to the BC Hydro Alliance of Energy Professionals (Alliance) members to ensure they are educated with respect to energy use and greenhouse gas emissions as well as trained on the details of the BC Hydro LCE Program. The Alliance is a network of contractors, consulting engineers, distributors and registered experts that provide energy management solutions to our customers. This group designs, manufactures, sells, and installs equipment that uses or affects the use of electricity. BC Hydro leverages the Alliance members' ability to sell and promote products, services, and our programs to our customers to encourage them to use electricity instead of other source of energy that produce more greenhouse gas emissions.	4(3)(b)

Table 3-2 below outlines an updated view of expenditures for the BC Hydro LCE Program components in each fiscal year, including the test period, to reflect changes related to the Government funded commercial new construction offer and customer project timing.

Table 3-2 – BC Hydro Funded Low Carbon Electrification Program Expenditures

BC Hydro LCE Program		Expenditures ($ million)[4]						
GGRR Regulation Subsection	**Program Component**	**2018**	**2019 (Actual)**	**2020 (Forecast)**	**2021 (Forecast)**	**2022 (Forecast)**	**2023 (Forecast)**	**Total**
4(3)(a), 4(3)(b)	Energy Management Studies and Incentives[5]	-	~~1.51~~ 0.23	~~3.10~~ 2.88	~~7.00~~ 3.66	~~2.49~~ 3.13	4.20	~~14.11~~ 14.10
4(3)(a)	Public Awareness	-	~~0.60~~ 0.25	~~0.91~~ 1.41	-0.02	~~0.00~~-	-	~~1.51~~ 1.68
4(3)(b)	Education & Training	-	~~0.01~~ -	~~0.04~~ -	-	-	-	~~0.05~~ 0.00
4(3)(c)	Research and Pilots	-	~~0.01~~ -	~~0.10~~ -	-	-	-	~~0.11~~ 0.00
4(3)(d)	Standards Enabler	-	~~0.23~~ -	~~0.65~~ 0.20	-0.68	-	-	0.88
Program Total		**-**	**~~2.35~~ 0.48**	**~~4.80~~ 4.49**	**~~7.00~~ 4.36**	**~~2.49~~ 3.13**	**4.20**	**~~16.65~~ 16.66**

[4] Expenditure shown in Table 3-2 include costs recorded in fiscal 2019 and fiscal 2020 (up to December 31st, 2019) as well as expenditures forecast for the remainder of fiscal 2020, 2021, 2022, and 2023.
[5] Labour for the BC Hydro Funded Low Carbon Electrification Program is included within the expenditure shown for Energy Management Studies and Incentives.

4.0 Cost Effectiveness

As shown in Table 2-1 and Table 3-2 included in section 2.0 and section 3.0, respectively, BC Hydro has chosen to engage in undertakings that are within one (or more) class of undertakings defined in sections 4(3)(a), 4(3)(b), 4(3)(c) or 4(3)(d) of the GGRR. Undertakings are in a class of undertakings defined in section 4(3)(a) and 4(3)(b) of the GGRR if they meet the cost-effective test. The cost-effectiveness test requires that each undertaking that is an undertaking within the class of undertakings defined by subsections 4(3)(a) or 4(3)(b) of the GGRR have a positive net present value (**NPV**), with the measure of a program's NPV being that of all of the programs that fall within the class of undertakings described in subsections 4(3)(a) and 4(3)(b) of the GGRR. Specifically, benefits mean all revenues BC Hydro expects to earn as a result of implementing LCE projects/programs falling under subsections 4(3)(a) or 4(3)(b), less revenues that BC Hydro expects to earn from the sale of that electricity to export markets. Costs mean all the costs BC Hydro expects to incur to implement LCE projects/programs falling under subsections 4(3)(a) or 4(3)(b), including development and administration costs. Furthermore, the GGRR cost-effectiveness test is measured only at the time BC Hydro decides to carry out a projects/programs. There is no other cost-effectiveness test applicable to prescribed undertakings.

The Table 4-1 below shows the NPV of all BC Hydro's projects/programs prescribed under section 4(3)(a) and 4(3)(b) of the GGRR including BC Hydro's proposed low carbon electrification expenditures for fiscal 2020 and fiscal 2021. ~~The NPV $134.7m indicates that these undertakings are cost-effective.~~

For the December 2019 Update, BC Hydro has updated Table 4-1 to reflect revisions made to the BC Hydro LCE Program since the February 2019 Report. The result of these revisions is a change in the NPV from $134.7 million in the February 2019 Report to $118.6 million in the December 2019 Update. While the NPV has reduced, these undertakings remain cost-effective.

The primary factors that drive the changes in NPV of BC Hydro LCE Program include the following:

- Changes in BC Hydro rate increases;
- Changes in the forecast timing of customer projects, which includes moving a large mining electrification opportunity out of the project forecast period based on updated customer information; and

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- No longer assuming participation of Commercial New Construction projects. These projects are now part of the program offer funded by Government through CleanBC. Instead, available BC Hydro funding will allow for additional opportunities from large industrial and commercial customers.

Table 4-1 – Cost Effectiveness

A	B	C	D	E		F		G	
GGRR	**Project/ Program/ Contract/ Expenditure**	**Expenditure ($ million)**	**Cost Effectiveness (F18 $million)**	**Additional Energy Consumption (MWh/year)**		**Additional Demand (MW)**		**Estimated GHG Emission Reductions (tonnes CO2e/year)**	
		Total	**GGRR NPV to 2030 (F2031)**	**Incremental**	**Cuml.**	**Incremental**	**Cuml.**	**Incremental**	**Cuml.**
4(3)(a)	Project 1	16.20	64.32	268,056	268,056	36.0	36.0	~~158,090~~ 160,274	~~158,090~~ 160,274
4(3)(a)	Project 2	13.50	110.20	223,380	491,436	30.0	66.0	~~131,742~~ 133,562	~~289,832~~ 293,836
4(3)(a)	Project 3	0.28	110.50	2,737	494,173	0.0	66.0	562	~~290,394~~ 294,398
4(3)(a)(b)	BC Hydro LCE Program[6]	~~15.66~~ 15.77	~~134.71~~ 118.63	~~108,337~~ 65,824	~~602,509~~ 559,996	~~17.3~~ 14.9	~~83.3~~ 80.9	~~56,896~~ 36,301	~~347,290~~ 330,699
	Total	**45.64**	**~~134.71~~ 118.63**	**~~602,509~~ 559,996**	**~~602,509~~ 559,996**	**~~83.3~~ 80.9**	**~~83.3~~ 80.9**	**~~347,290~~ 330,699**	**~~347,290~~ 330,699**

One of the legal consequences of BC Hydro's program or project being in a class of prescribed undertakings under section 18 of the *Clean Energy Act* is that BC Hydro is entitled to recover the costs of our electrification programs or projects in rates. The expenditures BC Hydro incurs in regard to its LCE DSM Projects/Programs are sought to be deferred to the DSM Regulatory Account in this application.

6 The BC Hydro LCE Program includes costs and benefits related to the class of undertakings defined in sections 4(3)(a) and 4(3)(b) of the GGRR.

18.0 D. PRESCRIBED UNDERTAKINGS UNDER THE CLEAN ENERGY ACT AND GREENHOUSE GAS REDUCTION (CLEAN ENERGY) REGULATION

Reference: CHAPTER 10 – DEMAND SIDE MANAGEMENT
Exhibit B-1, Appendix Y, pp. 3, 8, 10–11; Exhibit B-1, Appendix BB, pp. 1–4, 10, 16 Prescribed undertakings

Page 3 of Appendix Y to BC Hydro's Application states:

> **…** the Low Carbon Electrification (LCE) Demand-Side Management (DSM) Projects/Programs that we have undertaken and plan to undertake over fiscal 2019, fiscal 2020 and fiscal 2021. All of our LCE DSM Projects/Programs are within one or more class of undertakings prescribed under the Greenhouse Gas Reduction (Clean Energy) Regulation, issued under section 18 of the Clean Energy Act.

Table 2-1 on page 8 of Appendix Y outlines BC Hydro's expenditures for the Initial LCE Projects for 2018 - 2022, at a total cost of $29.71M.

Table 3-2 on page 11 of Appendix Y outlines BC Hydro Funded Low Carbon Electrification Program Expenditures for 2018 – 2022, at a total cost of $16.65M.

Pages 1–4 of Appendix BB, Attachment 2 - Fiscal 2018 Annual Report No. 1 state:

> The GGRR Reporting Requirements also requests a report by a Fairness Advisor on the competitiveness of any call process held during the reporting period. BC Hydro confirms that in Fiscal 2018 it did not hold any call processes in regard to its LCE DSM Project/Programs or its LCE Infrastructure Projects.

Table 2 in Appendix BB sets out Electrification Information for LCE DSM Projects/Programs for Year Ending March 31, 2018 and shows the actual cost at $0.22M. Table 5 in Appendix BB sets out the LCE Infrastructure Projects Results as of March 31, 2018.

2.18.2 Is the list, description and cost of prescribed undertakings outlined at Appendices Y and BB still accurate and up to date?

2.18.2.1 If not, please update Appendices Y and BB to include all prescribed undertakings up to December 31, 2019.

RESPONSE:

Please refer to BC Hydro's response to BCUC Panel IR 2.18.2 for updated information on the prescribed undertakings outlined in Appendices Y and BB.

18.0 D. PRESCRIBED UNDERTAKINGS UNDER THE CLEAN ENERGY ACT AND GREENHOUSE GAS REDUCTION (CLEAN ENERGY) REGULATION

Reference: CHAPTER 10 – DEMAND SIDE MANAGEMENT
Exhibit B-1, Appendix Y, pp. 3, 8, 10–11; Exhibit B-1, Appendix BB, pp. 1–4, 10, 16 Prescribed undertakings

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Table 2 in Appendix BB sets out Electrification Information for LCE DSM Projects/Programs for Year Ending March 31, 2018 and shows the actual cost at $0.22M. Table 5 in Appendix BB sets out the LCE Infrastructure Projects Results as of March 31, 2018.

2.18.2 Is the list, description and cost of prescribed undertakings outlined at Appendices Y and BB still accurate and up to date?

2.18.2.2 Does BC Hydro have any projects or programs under the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) in addition to the programs and projects described in Appendices Y and BB?

RESPONSE:

BC Hydro does not currently have any projects or programs under the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) other than those listed in the updated Appendix Y (filed as Attachment 1 to BC Hydro's response to BCUC Panel IR 2.18.2) and those listed in the Fiscal 2019 GGRR Annual Report (filed as Attachment 1 to BC Hydro's response to BCUC Panel IR 2.18.1).

18.0 D. PRESCRIBED UNDERTAKINGS UNDER THE CLEAN ENERGY ACT AND GREENHOUSE GAS REDUCTION (CLEAN ENERGY) REGULATION

Reference: CHAPTER 10 – DEMAND SIDE MANAGEMENT
Exhibit B-1, Appendix Y, pp. 3, 8, 10–11; Exhibit B-1, Appendix BB, pp. 1–4, 10, 16 Prescribed undertakings

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> **…** the Low Carbon Electrification (LCE) Demand-Side Management (DSM) Projects/Programs that we have undertaken and plan to undertake over fiscal 2019, fiscal 2020 and fiscal 2021. All of our LCE DSM Projects/Programs are within one or more class of undertakings prescribed under the Greenhouse Gas Reduction (Clean Energy) Regulation, issued under section 18 of the Clean Energy Act.

Table 2-1 on page 8 of Appendix Y outlines BC Hydro's expenditures for the Initial LCE Projects for 2018 - 2022, at a total cost of $29.71M.

Table 3-2 on page 11 of Appendix Y outlines BC Hydro Funded Low Carbon Electrification Program Expenditures for 2018 – 2022, at a total cost of $16.65M.

Pages 1–4 of Appendix BB, Attachment 2 - Fiscal 2018 Annual Report No. 1 state:

> The GGRR Reporting Requirements also requests a report by a Fairness Advisor on the competitiveness of any call process held during the reporting period. BC Hydro confirms that in Fiscal 2018 it did not hold any call processes in regard to its LCE DSM Project/Programs or its LCE Infrastructure Projects.

Table 2 in Appendix BB sets out Electrification Information for LCE DSM Projects/Programs for Year Ending March 31, 2018 and shows the actual cost at $0.22M. Table 5 in Appendix BB sets out the LCE Infrastructure Projects Results as of March 31, 2018.

2.18.3 Please provide a high level rate impact estimate of BC Hydro's prescribed undertakings as a result of the programs and projects outlined in Appendices Y and BB. If there are any updates please also provide any updated rate impact estimate.

RESPONSE:

BC Hydro's Low Carbon Electrification (LCE) DSM Projects/Programs are estimated to decrease cumulative bills in the Test Period by approximately 0.1 per cent. This estimate is based on the forecast included in the Application and the Evidentiary Update.

BC Hydro's Low Carbon Electrification (LCE) DSM Projects/Programs, updated for actual results and BC Hydro's latest forecast (as at December 2019) does not change the estimated decrease in cumulative bills in the Test Period (i.e., the estimated decrease remains at approximately 0.1 per cent).

18.0 D. PRESCRIBED UNDERTAKINGS UNDER THE CLEAN ENERGY ACT AND GREENHOUSE GAS REDUCTION (CLEAN ENERGY) REGULATION

Reference: CHAPTER 10 – DEMAND SIDE MANAGEMENT
Exhibit B-1, Appendix Y, pp. 3, 8, 10–11; Exhibit B-1, Appendix BB, pp. 1–4, 10, 16 Prescribed undertakings

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Table 2-1 on page 8 of Appendix Y outlines BC Hydro's expenditures for the Initial LCE Projects for 2018 - 2022, at a total cost of $29.71M.

Table 3-2 on page 11 of Appendix Y outlines BC Hydro Funded Low Carbon Electrification Program Expenditures for 2018 – 2022, at a total cost of $16.65M.

Pages 1–4 of Appendix BB, Attachment 2 - Fiscal 2018 Annual Report No. 1 state:

> The GGRR Reporting Requirements also requests a report by a Fairness Advisor on the competitiveness of any call process held during the reporting period. BC Hydro confirms that in Fiscal 2018 it did not hold any call processes in regard to its LCE DSM Project/Programs or its LCE Infrastructure Projects.

Table 2 in Appendix BB sets out Electrification Information for LCE DSM Projects/Programs for Year Ending March 31, 2018 and shows the actual cost at $0.22M. Table 5 in Appendix BB sets out the LCE Infrastructure Projects Results as of March 31, 2018.

2.18.4 Please provide a copy of any reports that have been prepared by a Fairness Advisor on the competitiveness of any call process held in relation to BC Hydro's LCE DSM Project/Programs or its LCE Infrastructure Projects.

RESPONSE:

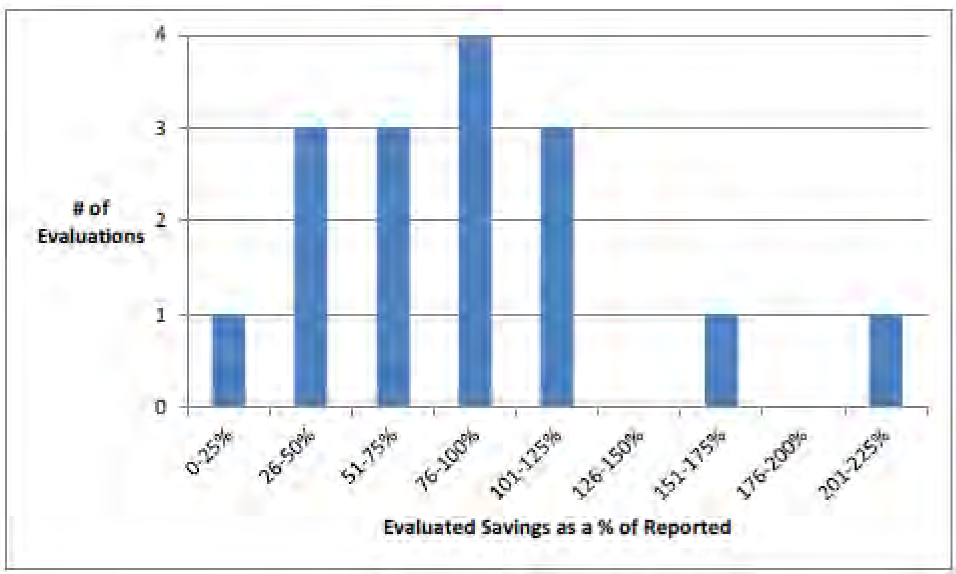
BC Hydro has not held any call processes in relation to BC Hydro LCE DSM Project/Programs or its LCE Infrastructure Projects. Accordingly, there has been no requirement to engage a Fairness Advisor to develop any reports.

Please refer to BC Hydro's response to ZONE II IR 1.27.1 for an explanation of the criteria that BC Hydro used to identify the initial LCE DSM projects and to BC Hydro's response to ZONE II IR 2.55.1 for a list of the steps taken by BC Hydro once an LCE DSM project was submitted.

19.0 E. DEMAND SIDE MANAGEMENT

Reference: DEMAND SIDE MANAGEMENT
Exhibit B-1, Appendix AA, p. 9
Evaluation results

On page 9 of Appendix AA of the Application BC Hydro provides a histogram summarizing the results of 16 DSM impact evaluations conducted by BC Hydro over a five-year period from fiscal 2014 through fiscal 2018. Eleven of the 16 evaluations found electricity savings to be less than reported while five evaluations found electricity savings to be more than reported.



2.19.1 Please provide the following data for the 16 DSM impact evaluations referenced above:

- The names of the programs, specifying the market segment if applicable.
- The estimated projected energy savings and expenditure for each of the 16 evaluated programs as accepted in the applicable expenditure schedules, and the total energy savings and expenditures for all 16 evaluated programs;
- The evaluated net impact savings and actual expenditures for each of the 16 evaluated programs, separately and cumulatively. In cases where the required level of granularity is not available, please include supporting explanations clarifying why this information is not available.

RESPONSE:

The table below provides the requested data for the 16 DSM impact evaluations referenced in the preamble to the question.

Program	Market Segment	Fiscal Years Evaluated	Energy Savings (New Incremental GWh/yr)		Expenditures ($ millions)	
			Projected	Evaluated Net	Projected	Actual
New Homes	**Residential**	**F2008-F2013**	**28.8**	**11.6**	**10.5**	**10.1**
Residential Retail – Appliances and Electronics	**Residential**	**F2011 – F2015 Q1/Q2**	**48.9**	**29.1**	**21.6**	**19.5**
Lighting	**Residential**	**F2013-F2015 Q1**	**18.4**	**58.4**	**6.4**	**6.0**
Low Income	**Residential**	**ESK F2011-F2016 ECAP F12-F16**	**25.2**	**27.1**	**19.6**	**14.0**
Commercial New Construction	**Commercial**	**F2008-F2011**	**36.8**	**34.0**	**19.5**	**15.4**
Product Incentive Program (Rebate and Direct Install)	**Commercial**	**F2011-F2013**	**174.1**	**191.5**	**47.7**	**43.3**
Power Smart Partners - Commercial	**Commercial**	**F2011-F2012**	**111.1**	**150.3**	**43.0**	**56.7**
Continuous Optimization	**Commercial**	**F2011-F2013**	**29.8**	**36.5**	**12.9**	**8.6**
New Plant Design	**Industrial**	**F2009-F2014**	**31.8**	**128.4**	**16.1**	**15.5**
Power Smart Partners - Transmission	**Industrial**	**F2012 – F2014**	**310.7**	**298.5**	**89.2**	**56.8**
Power Smart Partners - Distribution	**Industrial**	**F2011-F2016**	**209.4**	**213**	**82.0**	**70.1**

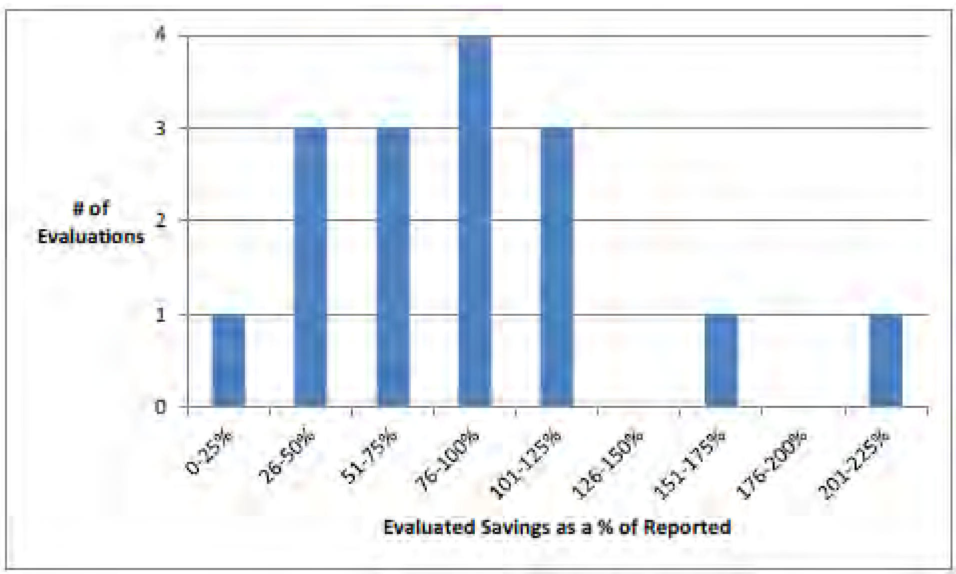
Program	Market Segment	Fiscal Years Evaluated	Energy Savings (New Incremental GWh/yr)		Expenditures ($ millions)	
Large General Service Rate	Rates - Commercial and Industrial (Distribution)	F2011-F2012	271.0	200	4.7	6.9
Large General Service Rate	Rates - Commercial and Industrial (Distribution)	F2014	188.7	77	0.7	0.4
Residential Inclining Block Rate	Rates – Residential	F2013-F2017	282.8	56	4.6	2.0
Televisions	Codes and Standards (Residential)	F2013-F2014	125.5	122[1]	n/a[2]	n/a[2]
General Service Lamps	Codes and Standards - Residential	F2012-F2017	599.8	251[1]	n/a[2]	n/a[2]
Subtotal – DSM Programs			1,025	1,178	368	316
Subtotal – Rates			742	333	10	9
Subtotal – Codes & Standards			725	373	n/a	n/a
Total			2,493	1,884	378	325

1. Evaluated savings for Codes and Standards initiatives are gross savings, not net savings.
2. BC Hydro's expenditures on codes and standards are not allocated to individual regulations.

19.0 E. DEMAND SIDE MANAGEMENT

Reference: DEMAND SIDE MANAGEMENT
Exhibit B-1, Appendix AA, p. 9
Evaluation results

On page 9 of Appendix AA of the Application BC Hydro provides a histogram summarizing the results of 16 DSM impact evaluations conducted by BC Hydro over a five-year period from fiscal 2014 through fiscal 2018. Eleven of the 16 evaluations found electricity savings to be less than reported while five evaluations found electricity savings to be more than reported.



2.19.2 Please explain in detail the meaning of "reported" in the graph above versus planned or evaluated savings, including identifying the type of party reporting if necessary. The response should contextualise the meaning of "reported" within the full DSM project cycle.

RESPONSE:

In the context of the referenced graph, reported savings refers to savings reported prior to the evaluation.

There are various stages in the overall energy savings planning and reporting cycle. Each stage allows new information to be incorporated into savings

estimation. The overall process includes feedback loops to allow new information from other stages in the process to be incorporated.

The cycle starts with planned (or forecast) savings, which are based on planned participation and engineering estimates of net unit savings. The Marketing department provides the planned savings estimates with assistance from Engineering.

Reported savings are the estimates of energy savings that have been achieved based on actual participation, as tracked by the Operations department. Initial reported savings are refined over time based on initial technical reviews, site inspections, and measurement and verification for larger projects. The technical review, site inspection, and measurement and verification are provided by the Engineering and Measurement & Verification groups.

Evaluated savings are the final stage in the process. Evaluated savings consist of the results of evaluations provided by the Evaluation department. Once an evaluation of the initiative has been completed, the reported savings will be updated to reflect the findings of the evaluation for the period covered by the evaluation. The reported and planned savings beyond the period covered by the evaluation are also reviewed to determine if they need to be updated based on the findings of the evaluation. Changes to reported and planned savings are reviewed and approved by the Conservation and Energy Management Governance Committee.

19.0 E. DEMAND SIDE MANAGEMENT

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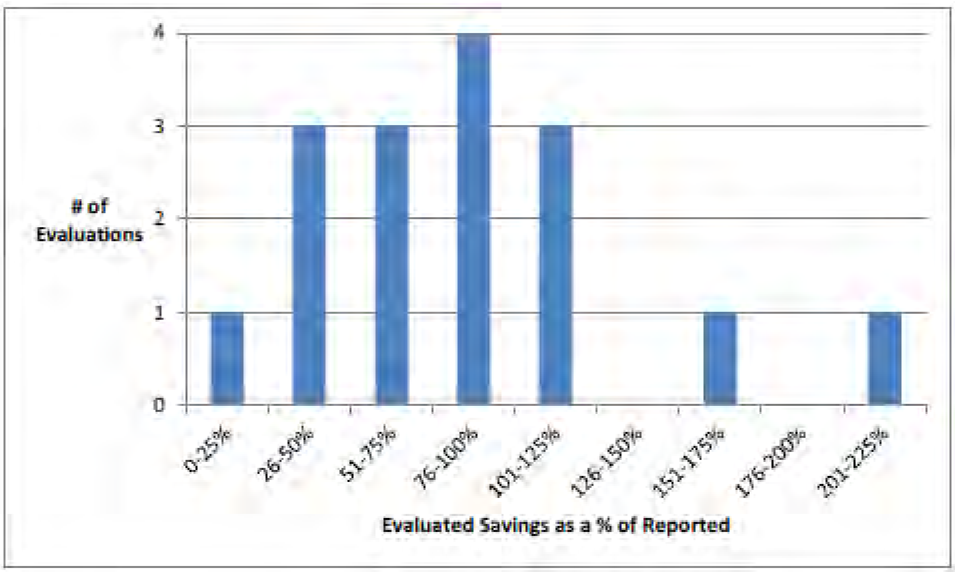

2.19.3 Please explain if and how these evaluation results are used by BC Hydro to adjust both DSM plans and energy forecasts, providing examples of where this has occurred.

RESPONSE:

This answer also responds to BCUC Panel IR 2.20.4.

Evaluation findings directly impact the reported savings for the period covered by the evaluation. The evaluation findings could also result in changes to the DSM plan assumptions (e.g., changes to the net-to-gross ratio) and savings for periods beyond that covered by the evaluation.

Any impacts on the DSM savings in forecast period will flow through into the net load forecast.

The following are examples of how evaluation results have been used to adjust our DSM savings.

Residential Inclining Block Fiscal 2013 to Fiscal 2017 Evaluation:

The Residential Inclining Block Fiscal 2013 to Fiscal 2017 Evaluation found that, in fiscal 2016 and fiscal 2017, there were no new incremental savings attributable to the conservation rate structure and that there were lower savings than reported over the fiscal 2013 to fiscal 2015 period.

In response to these evaluation findings, the evaluated savings were adopted as the actual savings for fiscal 2013 to fiscal 2017. We also concluded that there were no new incremental savings from the Residential Inclining Block rate from fiscal 2018 onwards and adjusted our planned numbers accordingly.

The RIB evaluation findings on elasticity also informed the elasticity values used in the Load Forecast.

General Service Lamp Regulation Fiscal 2012 to Fiscal 2017 Evaluation:

The evaluation results showed cumulative savings over the fiscal 2012 to fiscal 2017 period to be lower than reported. The variance was largely due to two factors:

- **The stock turnover of lamps to higher efficiency alternatives taking longer than originally anticipated; and**
- **The mix of bulb wattages were different than originally assumed.**

These assumption changes were updated for the reported and planned savings for the General Service Lamp Regulation.

As a result of the longer turnover timeframe for the lighting regulation, the baseline assumption for lighting technologies was adjusted for the Low Income Program and Residential Retail Program, resulting in an increase in reported and planned savings.

TV Regulation Fiscal 2015 to Fiscal 2018 Evaluation:

Evaluation results showed that incremental savings from fiscal 2015 to fiscal 2018 were lower than reported. In addition to updating reported savings, the following assumptions were changed for the planned savings from the TV regulation as a result of the evaluation findings:

- **Hours of use were lowered;**
- **Unit energy savings were reduced to update for the larger screen size and the slightly lower efficiency levels; and**
- **The TV replacement rates were lowered.**

This evaluation did not impact other DSM program assumptions, as televisions are no longer offered in any of the residential programs.

Power Smart Partners - Transmission Fiscal 2012 to Fiscal 2014 Evaluation:

The evaluation results showed a higher net-to-gross ratio and a lower realization rate over the fiscal 2012 to fiscal 2014 period. In addition to adopting the evaluated net-to-gross ratio and realization rate for reported savings during the evaluation timeframe, the evaluated net-to-gross ratio was also applied to reported savings after fiscal 2014, as well as to planned savings.

20.0 E. DEMAND SIDE MANAGEMENT

Reference: DEMAND SIDE MANAGEMENT
Exhibit B-12, BCUC IR 271.2
Historical evaluation of DSM initiatives

In response to BCUC IR 271.2 requesting copies of the last three completed evaluation reports, BC Hydro provided copies of the following:

- Television Market Evaluation: Fiscal 2015 to Fiscal 2018;
- Leaders in Energy Management – Commercial: Fiscal 2013 to Fiscal 2017; and
- Commercial Building Code Evaluation Report: September 2009 to December 2014.

Page v of the Television Market Evaluation states:

> This is a market evaluation that examines changes in the market for new televisions in B.C. in the context of 2013 and 2015 provincial regulations for TV energy efficiency…. BC Hydro demand side management programs targeting the TV market were available from F2009 to F2014, which is prior to the evaluation period.

Page 12 of the Television Market Evaluation BC Hydro states:

> BC Hydro forecasts and reports gross electricity savings associated with energy efficient product regulations in its demand-side management (DSM) plan and uses these estimates in its load forecast. BC Hydro supports the development and introduction of energy efficient product standards and regulations by funding market and technical research, and delivering DSM programs to ready the market for changes to regulations. During the four year period covered in the gross savings calculation, there were no DSM programs or offers in place targeting the TV market. This evaluation estimates the electricity savings in BC Hydro's service territory due to changes in the efficiency of TVs sold in B.C., which includes the influence of provincial TV regulations operating in the context of external drivers and the evolving global TV market. The evaluation does not attempt to determine the share of savings directly attributable to changes in regulation or other specific actions.

Page 24 of the Television Market Evaluation states:

> 9. Gross evaluated savings in the new TV market were 50, 45, 42 and 33 GWh/yr, respectively, for each year from F2015 to F2018. In contrast,

the reported savings for each year over the same period ranged from 64 GWh/yr to 69 GWh/yr.

11. The evaluated gross savings (in the new TV market) were consistently lower than the reported savings, and the gap increased in each year….

Page xii of the Leaders in Energy Management – Commercial (LEM-C) Evaluation states that BC Hydro's LEM-C program achieved 11 percent more savings during fiscal years F2013 to F2017 than was expected.

2.20.1 As BC Hydro did not provide any DSM programs in the TV market segment over the four year period covered by the gross savings calculation, please clarify the intent of the TV market evaluation, and similar evaluations.

RESPONSE:

BC Hydro evaluates all components of its DSM Plan including programs, codes and standards and conservation rates. The referenced TV market evaluation is for a codes and standards initiative.

BC Hydro takes action to support codes and standards development, and evaluates codes and standards initiatives since they can represent a significant portion of the savings in the DSM Plan. These evaluations can also inform future program development.

BC Hydro evaluates the gross savings of codes and standards initiatives with the primary objective of understanding the impact on the net load forecast. An example of how the TV market evaluation informed the forecast of future codes and standards savings is provided in BC Hydro's response to BCUC Panel IR 2.19.3.

As noted in BC Hydro's response to BCUC IR 2.271.1.2, BC Hydro's evaluation criteria for codes and standards initiatives are different than for programs. Specifically, only the codes and standards initiatives with the largest savings are targeted and only 50 per cent of cumulative reported savings are targeted every three to six years. This is a lower level of coverage relative to programs. As mentioned above, codes and standards evaluations also typically evaluate gross savings only, which can be less work intensive.

In BC Hydro's view, this is the appropriate coverage for the evaluation of codes and standards initiatives. It balances the trade-off between the relatively high proportion of energy savings and the relatively low proportion of expenditures in BC Hydro's DSM Plan.

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2.20.2 Please confirm in what year BCUC acceptance of the DSM expenditures on the LEM-C program were granted and provide the planned expenditures and forecast savings at the time the application was filed.

RESPONSE:

The history of BCUC acceptance of expenditures on the Leaders in Energy Management – Commercial[1] (LEM-C) program is as follows:

- **Fiscal 2013 expenditures for LEM-C were included in BC Hydro's Amended Fiscal 2012 to Fiscal 2014 Revenue Requirements Application, and approved in June 2012 (BCUC Order No. G-77-12A);**
- **Fiscal 2014 to Fiscal 2016 expenditures for LEM-C were included in BC Hydro's Fiscal 2015 to Fiscal 2016 Revenue Requirements Application, and approved in March 2014 (BCUC Order No. G-48-14); and**
- **Fiscal 2017 expenditures for LEM-C were included in the Previous Application, and approved in March 2018 (BCUC Order No. G-47-18).**

The table below shows planned expenditures and savings at the time each application was filed.

	F2013	F2014	F2015[2]	F2016[2]	F2017
Expenditures ($ million)	**25.9**	**28.4**	**24.3**	**26.4**	**27.9**
Energy Savings (New Incremental GWh/year)	**82**	**66**	**70**	**56**	**91**

1 Prior to the Previous Application, this program was called Power Smart Partners – Commercial.

2 In Fiscal 2015, the Product Incentive program was integrated with the Power Smart Partners program, and managed, operated, reported, and evaluated as one program. This column provides the combined value for both components as shown in the Fiscal 2015 to Fiscal 2016 Revenue Requirements Application.

20.0 E. DEMAND SIDE MANAGEMENT

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2.20.2 Please confirm in what year BCUC acceptance of the DSM expenditures on the LEM-C program were granted and provide the planned expenditures and forecast savings at the time the application was filed.

2.20.2.1 Please provide a table comparing planned to actual expenditures and evaluated net savings for this program.

RESPONSE:

The table below provides planned and actual expenditures as well as planned and evaluated savings for the Leaders in Energy Management – Commercial program.

	F2013	**F2014**	**F2015**	**F2016**	**F2017**
Planned expenditures ($ million)	**25.9**	**28.4**	**24.3**	**26.4**	**27.9**
Actual expenditures ($ million)	**28.9**	**24.8**	**22.1**	**22.0**	**22.9**
Planned savings (new incremental GWh/yr)[1]	**82**	**66**	**70**	**56**	**91**
Evaluated savings (new incremental GWh/yr)	**93.8**	**76.0**	**64.2**	**75.4**	**85.9**

[1] **Planned and evaluated savings include adjustment for net-to-gross ratios.**

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2.20.3 Please provide the estimated cost of both evaluations, including a breakdown by internal and external resources.

RESPONSE:

Estimated costs for the Television market evaluation are as follows:

TV Market Evaluation (F2015-F2018): Estimated Costs	
Internal Resources	**Amount ($)**
Labour	**76,000**
External Resources	
Contract services: engineering support	**1,175**
Consulting: External Advisors, report review	**6,400**
Other: TV Sales data purchases (2 sets)	**40,930**
Total Cost	**124,505**

Estimated costs for the LEM-C program evaluation are as follows:

LEM-C Program Evaluation (F2013-F2017): Estimated Costs	
Internal Resources	**Amount ($)**
Labour	**170,100**
External Resources	
Contract services: engineering support and interviews	**10,800**
Contract services: Surveys	**20,700**
Consulting: External Advisors, report review	**8,100**
Total Cost	**209,700**

20.0 E. DEMAND SIDE MANAGEMENT

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2.20.4 In cases where evaluated DSM savings are found to be lower, or higher, than originally anticipated, please discuss how these results are used by BC Hydro to adjust forecast DSM savings, making reference to both DSM plans, and load forecast processes.

RESPONSE:

Please refer to BC Hydro's response to BCUC Panel IR 2.19.3 for examples of how evaluation results are used to adjust both the DSM Plan and the load forecast.

21.0 E. DEMAND SIDE MANAGEMENT

Reference: DEMAND SIDE MANAGEMENT
Exhibit B-12, BCUC IR 271.1.1
Selection of external DSM advisors

In response to BCUC IR 271.1.1 regarding the criteria for selecting external DSM advisors to assist with DSM evaluations, BC Hydro states:

> As indicated in BC Hydro’s response to BCUC IR 2.271.1, BC Hydro has had long-term relationships with its external advisors. There have been two changes with external advisors since fiscal 2009. These are:
>
> - David Sumi was replaced by Rafael Friedmann in fiscal 2011 because he changed consulting firms and his new firm could have been in a conflict of interest for other potential work on DSM for BC Hydro; and
> - Ed Vine was replaced by Econoler in fiscal 2018 because of Ed Vine’s retirement.
>
> Criteria used by BC Hydro to select the external advisor include:
>
> - Free from conflict of interest, meaning that they were not currently (and had not been in the past) providing services to BC Hydro related to DSM program design or implementation;
> - Extensive experience conducting and overseeing Demand-Side Management (DSM) evaluation work;
> - Extensive and current knowledge of DSM evaluation methodologies; Subject matter expertise in the disciplines of statistics, engineering, social sciences, and/or economics; and
> - Record of work with other utilities.

2.21.1 Please provide copies of the resumes for the Evaluation Advisors referenced in the table provided in response to BCUC 271.1, confidentially if necessary.

RESPONSE:

Evaluation advisors listed in the table provided in BC Hydro’s response to BCUC IR 2.271.1 include Econoler, Rafael Friedmann, Ed Vine, Steven Braithwait and David Sumi.

Attachment 1 provides resumés for the personnel at Econoler, Rafael Friedmann, and Ed Vine. Pierre Baillargeon has been the main advisor from Econoler, drawing on other resources as needed.

This attachment is being provided confidentially to the BCUC only as it contains personal information including work and education history and home addresses and phone numbers.

BC Hydro does not have Steven Braithwait's resumé on file but an on-line profile from Christensen and Associates is included in the attachment.

BC Hydro could not locate any records on David Sumi. His involvement was limited to fiscal 2010.

CONFIDENTIAL ATTACHMENT

FILED WITH BCUC ONLY

21.0 E. DEMAND SIDE MANAGEMENT

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> - Extensive and current knowledge of DSM evaluation methodologies; Subject matter expertise in the disciplines of statistics, engineering, social sciences, and/or economics; and
> - Record of work with other utilities.

2.21.2 Please discuss BC Hydro's views on the risks and benefits of using the same External Advisors for long periods of time, and how BC Hydro ensures that the External Advisors remain neutral.

RESPONSE:

By retaining the same External Advisors over time, BC Hydro is able to choose and retain high-quality External Advisors with an understanding of BC Hydro's business and in particular, its DSM initiatives. This leads to higher quality advice because the pool of qualified consultants is small, particularly when consultants with a conflict of interest are removed. It also avoids the additional time required to frequently onboard new consultants.

Risks of using the same External Advisors over time include the perception that their advice is biased because of longstanding contract with BC Hydro.

BC Hydro has safeguards in place to ensure that the External Advisors stay neutral:

- **First, BC Hydro utilizes two External Advisors, which allows for different perspectives to be provided;**
- **Second, contracts are renewed approximately every two to three years, which provides an opportunity to ensure that the desired criteria for External Advisors, listed in the preamble to the question, are being met;**
- **Third, the advice and comments of the External Advisors are not edited by BC Hydro and are included verbatim in their presentation to the Evaluation Oversight Committee, as well as their memo appended to evaluations; and**
- **Fourth, BC Hydro selects External Advisors with extensive industry experience in DSM evaluation work and with a professional and academic background. These External Advisors have a self-interest in providing quality and unbiased advice to maintain their standing in the industry.**