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June 21, 2019

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

Dear Mr. Wruck:

RE: Project No. 1598969
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Electricity Purchase Agreement (EPA) Renewals – Sechelt Creek Hydro, Brown Lake Hydro, and Walden North Hydro

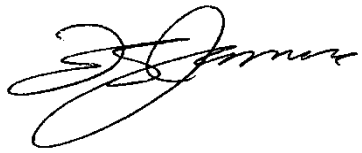
BC Hydro writes in accordance with Commission Order No. G-91-19 to provide its responses to Round 2 information requests as follows:

Exhibit B-12	Responses to Commission IRs (Public Version)
Exhibit B-12-1	Responses to Commission IRs (Confidential Version)
Exhibit B-13	Responses to Commission Confidential IRs (Confidential)
Exhibit B-14	Responses to Interveners IRs (Public Version)
Exhibit B-14-1	Responses to Interveners IRs (Confidential Version)
Exhibit B-15	Responses to Interveners Confidential IRs (Confidential)

BC Hydro is filing a number of IR responses and/or attachments to responses confidentially with the BCUC. 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 or in Exhibit B-3. 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 Geoff Higgins at 604-623-4121 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,



Fred James
Chief Regulatory Officer

st/tl

Enclosure

1.0 A. BC ENERGY OBJECTIVES CONSIDERATION

Reference: SALMON MIRGRATION – ECONOMIC AND FIRST NATION IMPACT
Exhibit B-5, BCUC Information Request (IR) 3.4, 3.4.1 and 5.1 Legal Obligation and First Nation Communities

In response to BCUC IR 3.4, BC Hydro states:

If the Sechelt Creek IPP facility were to be decommissioned, BC Hydro bears no legal obligation for mitigating any potential impacts associated with the Sechelt Creek facility.

In response to BCUC IR 3.4.1 BC Hydro submits the impact to salmon spawning at Sechelt Creek Independent Power Producer (IPP) in absence of an electricity purchase agreement (EPA):

The Sechelt Creek IPP has advised BC Hydro of the following:

If the facility were to be decommissioned, it is not expected to improve any potential historical negative environmental impacts and given that decommissioning would have a negative impact on the spawning channel, decommissioning is expected to have a negative environmental impact.

In response to BCUC IR 5.1 BC Hydro submits the impact to salmon migration at Walden North IPP in absence of an EPA:

Recent BC Hydro studies have shown that not maintaining the dilution ratio during the salmon migration period leads to a change in salmon migratory behaviour and a failure of salmon to successfully migrate to the Seton River and spawning areas.

2.1.1 In the absence of an EPA with the Sechelt Creek IPP and the Walden North IPP, please discuss whether BC Hydro has a legal responsibility from the existing energy purchasing agreement for preserving or restoring the salmon resources at Cayoosh Creek and Sechelt Creek, respectively. If so, please describe the legal obligation, scope of work, associated costs and possible impact on ratepayers.

RESPONSE:

BC Hydro has no legal responsibility arising from either of the existing EPAs with respect to preserving or restoring the salmon resources at Cayoosh Creek or Sechelt Creek, respectively. BC Hydro additionally notes that in the absence of a new EPA with BC Hydro:

- **The Sechelt Creek IPP has indicated that it is uncertain whether the Sechelt Creek facility would be decommissioned or decommissioned earlier, and**
- **The Walden North IPP has stated that the Walden North facility will not be decommissioned or decommissioned earlier.**

However, should one or both of these IPP facilities be decommissioned sometime in the future, there may be impacts on salmon resources but BC Hydro would bear no legal responsibility due to its existing EPAs.

1.0 A. BC ENERGY OBJECTIVES CONSIDERATION

Reference: SALMON MIRGRATION – ECONOMIC AND FIRST NATION IMPACT
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Recent BC Hydro studies have shown that not maintaining the dilution ratio during the salmon migration period leads to a change in salmon migratory behaviour and a failure of salmon to successfully migrate to the Seton River and spawning areas.

2.1.2 Does the Cayoose Creek Indian Band and shíshálh Nation, respectively, rely on the salmon migration or spawning channel as a natural and/or financial resource for their aboriginal communities? If so, please quantify these benefits and how the Cayoose Creek Indian Band and shíshálh Nation would be affected.

RESPONSE:

<u>Sechelt Creek IPP</u>

The Sechelt Creek IPP has provided the following additional information to BC Hydro in response to this question:

> **The Sechelt Creek spawning channel is an important natural and financial resource for the shíshálh Nation community.**
>
> **The people of shíshálh Nation, known as the salmon people, have a clear and direct linkage to the health of Salmon Inlet, and through their actions and management have not only provided more food stock for their people, but have also brought back the salmon and other marine life that comes with them. With porpoise and whale sightings now more common, shíshálh Nation is very supportive and proud of the collaboration with the Sechelt Creek hydro facility, which has contributed to the revitalization of the area.**
>
> **In 2015, the benefit of the spawning channel to the economy of B.C. was clearly demonstrated with the opening of the commercial fishery for the first time in 50 years and the Nation was directly involved in the management of this fishery. The fishery yielded approximately 95,000 pink salmon.**
>
> **The success of the spawning channel has been celebrated and acknowledged on numerous occasions, including the Sechelt Creek Celebration entitled "Honouring the Vision of the shíshálh Elders", and the Blue Planet Prize awarded by the International Hydropower Association in recognition of excellence in sustainable development.**
>
> **Decommissioning of the project and its associated spawning and rearing channel would have substantial negative implications not only to the recovering fishery, but also to the natural heritage and biodiversity of the area. Ultimately, the loss of this facility would undermine the legacy of the shíshálh elders who contributed their knowledge and wisdom to this endeavour.**

Walden North IPP

The Walden North IPP has provided the following additional information to BC Hydro in response to this question:

> **The Seton/Cayoose salmon population is of great natural importance to the Cayoose Creek Indian Band (Sekw'el'was). Several elements of the operation of the Walden North Hydro Facility provide specific protection and enhancement to the Cayoosh/Seton salmon population. These include Department of Fisheries and Oceans (DFO)-mandated requirements to minimize the flow contribution of Cayoosh Creek to the Seton River (by diverting the Walden tailrace to the Seton Reservoir) during two critical 6-week salmon spawning migrations in summer and fall (total 12 weeks annually). Each period matches with a sockeye salmon sub-species (Gates Creek and Portage Creek strains). The maximum flow target ratios (20% and 10%, respectively) are achieved by the Facility remaining on-line during these 12 weeks.Salmon are further enhanced by the operation of the existing Walden salmon enhancement channel which is fed entirely from the Walden Facility tailrace flow. These two elements (water flow targets in Cayoosh Creek and the spawning channel operation) are examples of how the Walden Facility advances salmon populations of great natural importance to the Cayoose.**
>
> **With respect to Natural Resource considerations: the salmon and other fish species, both resident and anadromous, are a significant food source for the local community and downstream communities. The salmon and other fish species are also a nutrient contribution to the ecosystem; the local wildlife and habitat are dependent on the fish-based nutrients to maintain a healthy population of flora and fauna. This includes locally harvested foodstuffs and wildlife, such as deer populations, that are a critical food source for the local communities.**
>
> **In addition, the Lillooet-based consulting firm Splitrock Environmental Sekw'el'was LP (Splitrock Environmental) is wholly owned and held in trust by Sekw'el'was Cayoose Creek Indian Band. The Splitrock Environmental management and technical team is over 75% Indigenous and employs several members of Sekw'el'was and neighbouring**

communities. Splitrock Environmental is a terrestrial and aquatic (fisheries) consulting service firm that offers fish and fish habitat studies (specific to Cayoosh/Seton salmon populations) such as fish salvages, fish habitat assessments, spawning channel assessments (fish enumeration) and maintenance, and hydro outage and maintenance support for protecting salmon populations. Revenue loss for salmon protection services would have a negative effect on Splitrock Environmental revenues.

2.0 B. ECONOMIC ANALYSIS

Reference: COST-EFFECTIVENESS
Exhibit B-5, BCUC IR 8.4, 11.3.1; Clean Energy BC, Response to Zapped Allegations of Overspending Billions on IPPs (Zapped Report Response) dated March 21, 2019, p. 15;[1]
Ministry's BC Hydro Phase 1 Report, p. 3
BC Hydro reliance on a Mid-C screening tool

BC Hydro states in response to BCUC IR 8.4 that it recently adopted the use of market price as a conservative interim assumption for evaluating energy during surplus and deficit periods.

Clean Energy BC (CEBC) states on page 15 of its Zapped Report Response:

The electricity in the Mid-C spot market is made up of the highly variable daily surplus of utilities located between California and Alberta.

The Ministry's BC Hydro Phase 1 Report states on page 3 that energy procurement is a major cost driver for BC Hydro, and that BC Hydro is currently forecast to be in energy surplus into the 2030s. BC Hydro states in response to BCUC IR 11.3.1 that, under the Mid-year forecast (planning view, using the updated 2016 load resource balance), BC Hydro will not be in an energy surplus situation from 2028.

2.2.1 Please provide BC Hydro's view on the difference between the Ministry's statement that the surplus will continue beyond 2030 and BC Hydro's forecast of the surplus ending in 2028.

RESPONSE:

The difference in the statements between the Ministry's "Comprehensive Review of BC Hydro: Phase 1 Report" and BC Hydro's response to BCUC IR 1.11.3.1 is due to the Ministry's use of the load resource balance (LRB) including planned resources, while BC Hydro used an LRB including only existing and committed resources (i.e., excluding planned resources).

[1] Clean Energy BC, Response to Zapped Allegations of Overspending Billions on IPPs (March 2019) https://www.cleanenergybc.org/wp-content/uploads/2019/03/CEBC-Report-Response-to-Zapped-allegation-of-billions-overspent.pdf

The Ministry report on page 22 gives the more complete context for its statement and indicates that its statement is based on the an LRB that includes existing and planned resources:

> **"While it is expected that this increase in electricity demand can be mostly met *with existing and planned resources*, BC Hydro may require additional volumes of new clean electricity to B.C. after 2030 to achieve the remaining 25% of emissions reductions needed to meet government's climate targets for 2030 and beyond."[2]**

BC Hydro's statement in BC Hydro's response to BCUC IR 1.11.3.1 is based on an LRB including only existing and committed resources. Please refer to BC Hydro's response to BCUC IR 1.11.2.2.1 for an explanation why the LRB with existing and committed resources (i.e., before planned resources) is used for evaluation EPA renewals.

[2] Ministry of Energy, Mines and Petroleum Resources, "Comprehensive Review of BC Hydro: Phase 1 Report", page 22

2.0 B. ECONOMIC ANALYSIS

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2.2.2 Does BC Hydro consider that use of a Mid-C estimate as a conservative assumption in evaluating EPA renewals would only be appropriate where the Mid-C estimate was lower than the cost of new generation? Please explain.

RESPONSE:

BC Hydro has adopted market prices as a conservative interim assumption for evaluating energy during surplus and deficit periods based on current market conditions. BC Hydro plans to update its LRMCs in the next IRP. "Interim assumption" means this is an assumption made for the period before the adoption of new LRMCs.

[1] Clean Energy BC, Response to Zapped Allegations of Overspending Billions on IPPs (March 2019) https://www.cleanenergybc.org/wp-content/uploads/2019/03/CEBC-Report-Response-to-Zapped-allegation-of-billions-overspent.pdf

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2.2.3 Please provide, in table and graphical form, a comparison of the ABB 2016, 2017 and 2018 Mid-C forecasts (in US $, before any losses/wheeling adjustments). Please also include on this table/graph Mid-C historical values (going back 10 years) and average forward prices (to the extent available).

RESPONSE:

The attachment to this response includes commercially sensitive information. This attachment has been redacted in the public version of the response as public disclosure could impact BC Hydro's commercial interests and ABB's commercial interests.

[1] Clean Energy BC, Response to Zapped Allegations of Overspending Billions on IPPs (March 2019) https://www.cleanenergybc.org/wp-content/uploads/2019/03/CEBC-Report-Response-to-Zapped-allegation-of-billions-overspent.pdf

CONFIDENTIAL ATTACHMENT

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3.0 B. ECONOMIC ANALYSIS

Reference: COST-EFFECTIVENESS
Zapped Report, p. 72, CEBC Zapped Report Response, p. 4
Maximizing the value of BC Hydro storage facilities

The Zapped Report states on page 72: "These IPPs now dominate the management of BC Hydro's Dispatchable power sources and have largely eliminated the trading advantage BC Hydro had held previously." CEBC's Zapped Report Response states on page 4 that buying intermittent energy from IPPs has rarely caused BC Hydro to spill water or sell surplus energy at extremely low prices.

2.3.1 Please explain whether "IPPs…have largely eliminated the trading advantage BC Hydro had held previously"?

RESPONSE:

BC Hydro does not believe it is appropriate to comment on the conclusions or the methodology of the report. The Zapped Report was commissioned by the Minister of Energy, Mines & Petroleum Resources to review BC Hydro's power acquisitions and provides an independent assessment of government policy. While BC Hydro provided background data and information to the consultant, the consultant developed his own independent analysis, conclusions and recommendations.

4.0 B. ECONOMIC ANALYSIS

Reference: MARKET PRICE ESTIMATES
Site C Inquiry Report, p, 152; Exhibit B-5-1, BCUC IR 21.1; Exhibit B-5, 29.1.1, 29.1.2, 29.1.3; Zapped Report, p. 7 Market Forecast

BC Hydro's Mid-C forecast based on the 2016 Spring ABB Power Reference Case is included on page 152 of the BCUC Site C Inquiry Report.

BC Hydro states in response to CEC IR 4.3 that its internal specialists work with their peers at Powerex to review ABB's forecast and modify it to fit BC Hydro's operating context if required. BC Hydro further states that it compared the ABB Mid-C forecast with the IHA Markit and the PIRA Energy Group Mid-C forecast, and that it has directly adopted ABB's Fall 2017 reference case.

BC Hydro states in BCUC IR 29.1.2 that it does not consider the Mid-C forecast to be overstated in years when the wind power purchase arrangement (PPA) price is below the estimated Mid-C price.

BC Hydro states in BCUC 29.1.3 that, from 1997 to 2018 (with the exception of the 2000 and 2001 California electricity crisis), the Mid-C average annual price has been lower than the levelized cost of new wind generation built in the same year. The Zapped Report states on page 7 that the Mid-C market trades both short term power (the next hour, the next day etc.) "spot rates" and future periods of power delivery going out as far as five years.

2.4.1 Please provide the most recent Mid-C IHS Markit and PIRA Energy Group forecast. Please compare (in an excel spreadsheet and graphically) the ABB Mid-C forecast with these alternative forecasts over the 40 year period of the EPAs. Please comment on any significant differences.

RESPONSE:

Please see the confidential spreadsheet attached to BC Hydro's response to BCUC IR 2.2.3.

BC Hydro notes that we no longer subscribe to PIRA Energy Group forecasts; the latest forecast available to BC Hydro from October 2017 is shown and compared to the latest IHS forecast from November 2018, the ABB Fall 2017 Reference Case forecast, and Market Forwards from June 2019. The three forecasts are not directly comparable due to their different vintages; however, the ABB forecast is

generally closer to the market forwards than the PIRA and IHS forecasts for the period out to 2024. Beyond 2024 the ABB forecast is lower than IHS and PIRA forecasts.

4.0 B. ECONOMIC ANALYSIS

Reference: MARKET PRICE ESTIMATES
Site C Inquiry Report, p, 152; Exhibit B-5-1, BCUC IR 21.1; Exhibit B-5, 29.1.1, 29.1.2, 29.1.3; Zapped Report, p. 7
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2.4.2 Please update the spreadsheet filed in response to BCUC IR 21.1 for the most recent ABB Power Reference Case.

RESPONSE:

Please see the confidential spreadsheet attached to BC Hydro's response to BCUC IR 2.2.3.

The worksheets in response to this IR (BCUC IR 2.4.2) include a Round 1 IR reference in the worksheet name. For example, tab 'BCUC 2.4.2 (1.25.1)' provides an update to the response to BCUC IR 1.25.1 with the Fall 2018 ABB Power Reference Case forecast.

BC Hydro notes an update to the 'BCUC 1.26.2' worksheet with the Fall 2018 Power Reference Case was not relevant and so that worksheet has not been included. There was also no relevant update to the 'BCUC 1.24.1.1' worksheet however that worksheet has been included again since some of its data is referenced in the 'BCUC 2.4.2 (1.24.1.2)' worksheet.

4.0 B. ECONOMIC ANALYSIS

Reference: MARKET PRICE ESTIMATES
Site C Inquiry Report, p, 152; Exhibit B-5-1, BCUC IR 21.1; Exhibit B-5, 29.1.1, 29.1.2, 29.1.3; Zapped Report, p. 7
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2.4.2 Please update the spreadsheet filed in response to BCUC IR 21.1 for the most recent ABB Power Reference Case.

2.4.2.1 If BC Hydro considers that adjustments are required to this reference case to fit BC Hydro's operating context, please provide and explain the adjustments.

RESPONSE:

BC Hydro is in the process of reviewing ABB's Fall 2018 Reference Case and has not completed its determination of the modifications that will be made. Typically, BC Hydro makes adjustments to price forecast model inputs including changes to reflect up to date information on the generation profiles of large hydro facilities in the Pacific Northwest that might not have been reflected in the ABB forecast model and changes to load inputs to reflect BC Hydro's most recent load forecast.

4.0 B. ECONOMIC ANALYSIS

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2.4.2 Please update the spreadsheet filed in response to BCUC IR 21.1 for the most recent ABB Power Reference Case.

2.4.2.2 Please explain how BC Hydro's wheeling and line losses adjustment to Mid-C in BCUC IR 21.1 was arrived at, and when it was last updated.

RESPONSE:

The spreadsheet provided in BC Hydro's response to BCUC IR 1.21.1 included several worksheets that responded to other market price-related IRs from the same round. In some of the worksheets, the wheeling adjuster and line loss assumptions used by the Site C Panel were applied to permit the comparison of the Site C Panel forecast with BC Hydro's F17-19 RRA forecast. In other worksheets, the current, publicly available values were used. These values (summarized below) are from Bonneville Power Administration (BPA) BP-18 rate

schedule which covers two years from October 1, 2017. BPA is expected to conclude their BP-20 FY2020-2021 rate case in the summer of 2019, with new rates taking effect on October 1, 2019 and applying for two years.

Current BPA Wheeling Rates (USD):

- **Hourly (firm and non firm): $4.23/MWh;**
- **Scheduling, System Control and Dispatch (Hourly): $0.93/MWh;**
- **Reactive Supply and Voltage Control from Generation Sources Service (GSR): $0.00/MWh; and**
- **Total = 4.23 + 0.93 + 0.00 = $5.16/MWh.**

Current BPA Line Losses (found in Schedule 9 of link below):

- **1.9 per cent of kWh delivered**

The BPA Rate Schedules are available at the links provided:

https://www.bpa.gov/Finance/RateInformation/RatesInfoTransmission/FY18-19/2018%20Rate%20Schedule%20Summary.pdf

https://www.bpa.gov/Finance/RateInformation/RatesInfoTransmission/FY18-19/Formula%20Rate%20Summary_FY18-19.pdf

https://www.bpa.gov/transmission/Doing%20Business/Tariff/Documents/bpa_oatt.pdf

5.0 B. ECONOMIC ANALYSIS

Reference: MARKET PRICE ESTIMATES
Exhibit B-5, BCUC IR 8.4, 21.2, 21.3; Site C Inquiry Report, Appendix A, p. 32;
Zapped Report, p. 47; Standing Offer Program (SOP) 2-Year Review, p. 9; Exhibit B-5, BCUC IR 8.4
Shape adjustment

BC Hydro provides in BCUC IR 21.3 monthly average Mid-C factors for peak and off-peak periods for each of the past 3 calendar years. The Site C Inquiry Report states in Appendix A, p. 32 "BC Hydro states that Site C (capacity 1,145 MW) can integrate 900 MW of wind".

The Zapped Report estimates on page 47 the market value of surplus energy, if sold at Mid-C, to be $25/MWh, stating that most of the surplus run-of-river energy is produced at freshet when the Mid-C rate is much lower than the annual average Mid-C rate. The SOP 2-Year Review includes a time of delivery table on page 9.

BC Hydro states in response to BCUC IR 8.4 that it recently adopted the use of market price as a conservative interim assumption for evaluating energy during surplus and deficit periods.

2.5.1 Does BC Hydro consider it reasonable (in evaluating the cost-effectiveness of EPAs) to use as a simplifying assumption monthly weightings only (as opposed to peak/off-peak/super-peak weightings)? Please explain, including whether this simplifying assumption could over or under value energy from run-of-river hydro generation facilities and hydro generation facilities with storage.

RESPONSE:

In general, for evaluating the cost-effectiveness of an EPA, BC Hydro believes it is appropriate to value deliveries in the peak / off-peak / super-peak time periods only when there is a significant likelihood that the associated facility will be able to deliver a specific volume of energy within these time periods. Typically, this is achieved through contractual measures to incent delivery (e.g., time of delivery table, firm energy requirements and liquidated damages) during these time periods.

BC Hydro considers it reasonable to assume a flat profile within each month when assessing the cost-effectiveness of the three EPA renewals in the Application because these EPA renewals do not contain any contractual obligations or incentives during these periods. As a result, BC Hydro's opportunity cost for these EPA renewals does not reflect these attributes.

BC Hydro is uncertain whether this assumption would generally undervalue or overvalue the energy from run-of-river facilities because:

- **there may be significant variability within the monthly generation;**
- **there may be some months with lower value and some months with higher value that may have an offsetting effect; and**
- **there may be significant year to year variation in performance within months and month to month.**

BC Hydro generally expects this assumption would undervalue the generation from storage hydro that has incentives or obligations to modify its generation to target higher value periods; however, it is uncertain how such provisions would impact the EPA price so it is not possible to provide an indication of the net impact on the analysis of cost-effectiveness.

5.0 B. ECONOMIC ANALYSIS

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Exhibit B-5, BCUC IR 8.4, 21.2, 21.3; Site C Inquiry Report, Appendix A, p. 32;
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BC Hydro states in response to BCUC IR 8.4 that it recently adopted the use of market price as a conservative interim assumption for evaluating energy during surplus and deficit periods.

2.5.2 Using the results provided in response to BCUC IR 21.3, please provide in graphical and excel spreadsheet form, the weighted average results by month (for example, by converting January peak and off-peak results into a monthly average).

RESPONSE:

Please refer to the attached spreadsheet.

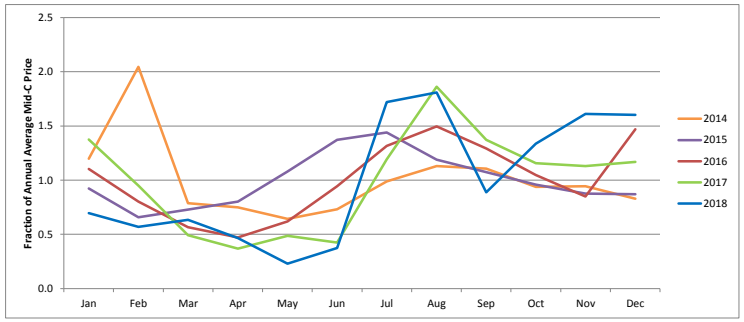
(Nominal $)

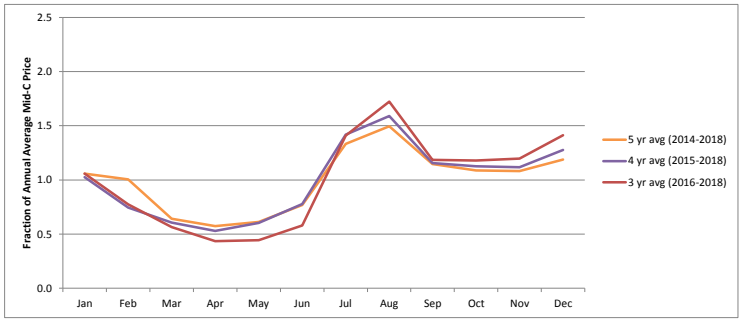
Monthly Average MidC price (USD/MWh)

	2014	2015	2016	2017	2018
Jan	$ 40.3	$ 21.7	$ 22.4	$ 30.0	$ 21.4
Feb	$ 68.7	$ 15.5	$ 16.3	$ 20.8	$ 17.5
Mar	$ 26.5	$ 17.1	$ 11.5	$ 10.7	$ 19.5
Apr	$ 25.2	$ 18.9	$ 9.6	$ 8.1	$ 14.4
May	$ 21.6	$ 25.4	$ 12.5	$ 10.6	$ 7.0
Jun	$ 24.6	$ 32.3	$ 19.1	$ 9.3	$ 11.5
Jul	$ 33.3	$ 33.8	$ 26.7	$ 26.1	$ 52.9
Aug	$ 37.9	$ 27.9	$ 30.3	$ 40.7	$ 55.7
Sep	$ 37.2	$ 25.2	$ 26.2	$ 30.0	$ 27.3
Oct	$ 31.5	$ 22.6	$ 21.3	$ 25.3	$ 41.1
Nov	$ 31.7	$ 20.6	$ 17.2	$ 24.7	$ 49.5
Dec	$ 27.9	$ 20.4	$ 29.8	$ 25.5	$ 49.2
All Hours	$ 33.6	$ 23.5	$ 20.3	$ 21.9	$ 30.8

Fraction of Annual Average Price (all hrs)

	2014	2015	2016	2017	2018	5 yr avg (2014-2018)	4 yr avg (2015-2018)	3 yr avg (2016-2018)
Jan	120%	92%	110%	137%	70%	106%	102%	106%
Feb	204%	66%	80%	95%	57%	100%	74%	77%
Mar	79%	73%	57%	49%	63%	64%	61%	56%
Apr	75%	80%	47%	37%	47%	57%	53%	44%
May	64%	108%	62%	49%	23%	61%	60%	44%
Jun	73%	137%	94%	42%	37%	77%	78%	58%
Jul	99%	144%	132%	119%	172%	133%	142%	141%
Aug	113%	119%	150%	186%	181%	150%	159%	172%
Sep	111%	107%	129%	137%	89%	115%	116%	118%
Oct	94%	96%	105%	116%	134%	109%	112%	118%
Nov	94%	88%	85%	113%	161%	108%	112%	120%
Dec	83%	87%	147%	117%	160%	119%	128%	141%





5.0 B. ECONOMIC ANALYSIS

Reference: MARKET PRICE ESTIMATES
Exhibit B-5, BCUC IR 8.4, 21.2, 21.3; Site C Inquiry Report, Appendix A, p. 32;
Zapped Report, p. 47; Standing Offer Program (SOP) 2-Year Review, p. 9; Exhibit B-5, BCUC IR 8.4
Shape adjustment

BC Hydro provides in BCUC IR 21.3 monthly average Mid-C factors for peak and off-peak periods for each of the past 3 calendar years. The Site C Inquiry Report states in Appendix A, p. 32 "BC Hydro states that Site C (capacity 1,145 MW) can integrate 900 MW of wind".

The Zapped Report estimates on page 47 the market value of surplus energy, if sold at Mid-C, to be $25/MWh, stating that most of the surplus run-of-river energy is produced at freshet when the Mid-C rate is much lower than the annual average Mid-C rate. The SOP 2-Year Review includes a time of delivery table on page 9.

BC Hydro states in response to BCUC IR 8.4 that it recently adopted the use of market price as a conservative interim assumption for evaluating energy during surplus and deficit periods.

2.5.2 Using the results provided in response to BCUC IR 21.3, please provide in graphical and excel spreadsheet form, the weighted average results by month (for example, by converting January peak and off-peak results into a monthly average).

2.5.2.1 Please also provide (in graphical and excel spreadsheet form) the same data for 2014 and 2016, the last three year average weighting by month (2016-2018), the last four year average weighting by month (2015-2018) and the last five year average weighting by month (2014-2018).

RESPONSE:

Please refer to the attachment to BC Hydro's response to BCUC IR 2.5.2.

5.0 B. ECONOMIC ANALYSIS

Reference: MARKET PRICE ESTIMATES
Exhibit B-5, BCUC IR 8.4, 21.2, 21.3; Site C Inquiry Report, Appendix A, p. 32;
Zapped Report, p. 47; Standing Offer Program (SOP) 2-Year Review, p. 9; Exhibit B-5, BCUC IR 8.4
Shape adjustment

BC Hydro provides in BCUC IR 21.3 monthly average Mid-C factors for peak and off-peak periods for each of the past 3 calendar years. The Site C Inquiry Report states in Appendix A, p. 32 "BC Hydro states that Site C (capacity 1,145 MW) can integrate 900 MW of wind".

The Zapped Report estimates on page 47 the market value of surplus energy, if sold at Mid-C, to be $25/MWh, stating that most of the surplus run-of-river energy is produced at freshet when the Mid-C rate is much lower than the annual average Mid-C rate. The SOP 2-Year Review includes a time of delivery table on page 9.

BC Hydro states in response to BCUC IR 8.4 that it recently adopted the use of market price as a conservative interim assumption for evaluating energy during surplus and deficit periods.

2.5.2 Using the results provided in response to BCUC IR 21.3, please provide in graphical and excel spreadsheet form, the weighted average results by month (for example, by converting January peak and off-peak results into a monthly average).

2.5.2.2 For each of the 3, 4 and 5 year averages provided above, which data set does BC Hydro consider most reflective of the expected monthly Mid-C price weightings going forward? Please explain.

RESPONSE:

BC Hydro does not consider any of the three historical averages to be reflective of the expected monthly Mid-C price weightings going forward. As described in BC Hydro's response to BCUC IR 1.21.3, the use of historical market price weightings should not be considered representative of future market price weightings. Rather, weightings based on long-term forecast market prices that incorporate market trends are more appropriate for long-term planning.

5.0 B. ECONOMIC ANALYSIS

Reference: MARKET PRICE ESTIMATES
Exhibit B-5, BCUC IR 8.4, 21.2, 21.3; Site C Inquiry Report, Appendix A, p. 32;
Zapped Report, p. 47; Standing Offer Program (SOP) 2-Year Review, p. 9; Exhibit B-5, BCUC IR 8.4
Shape adjustment

BC Hydro provides in BCUC IR 21.3 monthly average Mid-C factors for peak and off-peak periods for each of the past 3 calendar years. The Site C Inquiry Report states in Appendix A, p. 32 "BC Hydro states that Site C (capacity 1,145 MW) can integrate 900 MW of wind".

The Zapped Report estimates on page 47 the market value of surplus energy, if sold at Mid-C, to be $25/MWh, stating that most of the surplus run-of-river energy is produced at freshet when the Mid-C rate is much lower than the annual average Mid-C rate. The SOP 2-Year Review includes a time of delivery table on page 9.

BC Hydro states in response to BCUC IR 8.4 that it recently adopted the use of market price as a conservative interim assumption for evaluating energy during surplus and deficit periods.

2.5.3 Please explain what shape of energy is assumed for the ABB annual average Mid-C price forecast (for example, is a flat shape assumed?)

RESPONSE:

As described in BC Hydro's response to BCUC IR 2.6.1, the market price modelling is carried out at an hourly resolution. The annual average Mid-C price forecast for any given year is the average value of the price modelled for each hour of that year.

5.0 B. ECONOMIC ANALYSIS

Reference: MARKET PRICE ESTIMATES
Exhibit B-5, BCUC IR 8.4, 21.2, 21.3; Site C Inquiry Report, Appendix A, p. 32;
Zapped Report, p. 47; Standing Offer Program (SOP) 2-Year Review, p. 9; Exhibit B-5, BCUC IR 8.4
Shape adjustment

BC Hydro provides in BCUC IR 21.3 monthly average Mid-C factors for peak and off-peak periods for each of the past 3 calendar years. The Site C Inquiry Report states in Appendix A, p. 32 "BC Hydro states that Site C (capacity 1,145 MW) can integrate 900 MW of wind".

The Zapped Report estimates on page 47 the market value of surplus energy, if sold at Mid-C, to be $25/MWh, stating that most of the surplus run-of-river energy is produced at freshet when the Mid-C rate is much lower than the annual average Mid-C rate. The SOP 2-Year Review includes a time of delivery table on page 9.

BC Hydro states in response to BCUC IR 8.4 that it recently adopted the use of market price as a conservative interim assumption for evaluating energy during surplus and deficit periods.

2.5.4 Please explain whether BC Hydro's conservative interim assumption adjusts for the seasonal energy shape? If no, please explain whether a market price estimate for run-of-river generation could therefore be considered optimistic rather than conservative?

RESPONSE:

Yes.

6.0 B. ECONOMIC ANALYSIS

Reference: MARKET PRICE ESTIMATES
Exhibit B-5, BCUC IR 27.1
Constraints

BC Hydro states in response to BCUC IR 27.1:

With respect to the freshet period, generally BC Hydro would want to avoid selling energy to Powerex given the typically low prevailing prices, but if required to sell by system conditions, a constraint that could arise is market opportunity since most parties are in a state of oversupply. In these circumstances, placing additional quantity in the market requires offering to sell at even lower prices, sometimes even negative (i.e., you must pay someone to take energy). … BC Hydro's market price forecast … does not reflect the constraints identified above.

2.6.1 Please explain why BC Hydro does not adjust the market price forecasts for the constraints identified above, and estimate the magnitude of the impact that they could have.

RESPONSE:

BC Hydro provides the following clarifications with respect to its response to BCUC IR 1.27.1 referred to in the preamble describing the temporal resolution of the market price forecast model and the constraints that are reflected in the model results. Circumstances that are not modelled are also described.

BC Hydro's Mid-C electricity price forecast is the result of a simulation (at an hourly resolution) of the supply-demand balance across different regions of the western interconnect. Market opportunity is reflected in the model's forecasted price of electricity, which is a function of the supply-demand balance. The resolution of the input data in the model limits the resolution of this balance and the resulting variability in prices.

Accordingly, BC Hydro's price forecast is based on hourly resolution of load forecasts and other highly variable inputs such as wind and solar generation forecasts. In contrast, other inputs such as gas price forecasts and hydro generation forecasts are input at a monthly resolution which is generally sufficient to capture the seasonal patterns in electricity prices associated with these inputs, such as depressed prices during the freshet and higher prices during cold winter periods/ warm summer periods.

Finer (sub-monthly) resolution of these inputs (for example hydro generation forecasts in the freshet) would be expected to lead to increased variability in modelled prices, which may be particularly low during periods of high inflows coinciding with high wind/solar generation and/or low demand.

When these circumstances actually occur, actual market opportunities to sell energy could be limited, and prevailing market prices may be very low. The reverse situation (e.g., low inflows, low wind/solar generation, and high demand) could also occur, leading to fewer market opportunities to purchase energy and higher market prices.

BC Hydro has not completed an analysis on the potential impact of sub-monthly resolution of the inputs that are currently modelled at monthly granularity on market opportunities or market price.

6.0 B. ECONOMIC ANALYSIS

Reference: MARKET PRICE ESTIMATES
Exhibit B-5, BCUC IR 27.1
Constraints

BC Hydro states in response to BCUC IR 27.1:

With respect to the freshet period, generally BC Hydro would want to avoid selling energy to Powerex given the typically low prevailing prices, but if required to sell by system conditions, a constraint that could arise is market opportunity since most parties are in a state of oversupply. In these circumstances, placing additional quantity in the market requires offering to sell at even lower prices, sometimes even negative (i.e., you must pay someone to take energy). … BC Hydro's market price forecast … does not reflect the constraints identified above.

2.6.1 Please explain why BC Hydro does not adjust the market price forecasts for the constraints identified above, and estimate the magnitude of the impact that they could have.

2.6.1.1 Please explain whether these constraints could decrease the value of freshet energy to a greater extent than that, (i) assumed in the Delivery Price Adjustment Table used in this Application, and/or (ii) based on the monthly averages of the last five year Mid-C average price weightings.

RESPONSE:

Please refer to the response to BCUC IR 2.6.1. As presented in BC Hydro's response to BCUC IR 1.21.3, there is substantial variability in the monthly factors from year to year driven by conditions specific to that year, and BC Hydro does not consider it appropriate to base the Delivery Price Adjustment factors on historical market prices.

7.0 B. ECONOMIC ANALYSIS

Reference: WIND PRICE ESTIMATES
Exhibit B-5, BCUC IR 8.4, 14.1, 16.4; CEBC Zapped Report Response, p, 22;
National Renewable Energy Laboratory (NREL) 2018 Annual Technology Baseline (ATB) Spreadsheet, Land-Based Wind tab, cell N497[1]
Estimated plant gate levelized cost of wind

BC Hydro includes in BCUC IR 14.1 recent Alberta (averages of $37/MWh - $40/MWh) and Saskpower (average of $42/MWh) wind bids, and states that BC Hydro expects that BC's wind prices would be higher due to more complex terrain and remote locations. BC Hydro also notes in the same response that in 2012 a similar sized BC wind project had a capital cost 38 per cent higher than in Alberta.

CEBC Zapped Report Response states that BC wind costs today would be expected in the range of $50 MWh. The NREL 2018 ATB Mid TRG 4 estimate of the levelized cost of wind for 2018 is US $39 (Can $50 using an exchange rate of 1.28) – 35 per cent higher than the Alberta's Phase 1 average bid of $37/MWh.

BC Hydro states in BCUC IR 8.4 that the long run marginal cost estimate for F2034 used in the Application ($104/MWh) is based on the cost of wind energy and is now considered out of date. BC Hydro states in BCUC IR 16.4 that the NREL 2018 ATB provides a reasonable assessment of wind energy costs for a generic US-based project, but that a more reasonable assessment would include BC specific cost details.

2.7.1 Does BC Hydro consider that, given its BC wind cost estimate including in the Application is now out of date, the 2018 NERL Mid TRG 4 estimates of the levelized cost of wind is a reasonable proxy for the BC cost of new wind generation? Please explain.

RESPONSE:

Although BC Hydro does not have an updated LRMC, we have conducted a preliminary assessment of the cost of wind from greenfield IPPs in B.C. Based on this assessment, the future cost of wind is estimated to be in the range of

[1] National Renewable Energy Laboratory (NREL) 2018 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/

$45/MWh to $67/MWh ($2018) at point of interconnection, and between $54/MWh and $80/MWh after accounting for adjustments for delivery to the Lower Mainland.

BC Hydro believes that an estimate of wind costs that takes into consideration cost factors relevant to the B.C. context such as terrain, remoteness and other market factors is a more reasonable proxy for the cost of new wind generation in B.C. Based on the same preliminary assessment, the current wind cost at point of interconnection is estimated to be in the range of $54/MWh to $73/MWh, which is higher than the 2018 NREL Mid TRG 4 mid case of $50/MWh cited above.

We plan to update the LRMC in our next IRP.

8.0 B. ECONOMIC ANALYSIS

Reference: WIND PRICE ESTIMATES
Exhibit B-5, BCUC IR 18.1, 18.1.1; Exhibit B-5-1, BCUC IR 8.1; RAP, Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements, 2011, p. 5;[1] Berkeley National Laboratory, Planning for a distributed disruption, 2016, pp. 59, 60;[2] BC Hydro SOP 2-Year Review, p. 13
Losses adjustment – methodology

BC Hydro provides its updated Peak Load Incremental losses for the Bulk Transmission system in BCUC IR 18.1, loss estimates in Tab 'input losses' in the spreadsheet provided in a confidential response to BCUC IR 8.1, and describes in BCUC IR 18.1.1 its methodology to calculate energy losses. A RAP 2011 paper titled "Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements" uses as a rule of thumb that marginal losses are about 1.5 times average losses.

Berkeley National Laboratory 2016 paper titled: "Planning for a distributed disruption: innovative practices for incorporating distributed solar into utility planning" states that the most comprehensive evaluation of system losses is a time-differentiated marginal loss rate and that Arizona, for example, applies a separate loss rate for each month while the California Public Utilities Commission (CPUC) provides time-differentiated "peak" and "energy" loss rates for each of its investor-owned utilities to apply to estimate the avoided cost of losses for demand-side measures.

The BC Hydro SOP 2-year review includes regional loss adjusters (original and updated) on page 13 of the SOP 2-Year review, and states that losses from the Peace Region have decreased from 13.7 per cent to 6.9 per cent, primarily due to lower system demand.

2.8.1 Please provide the 2018 Peak Load Incremental Losses report.

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1 RAP, Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements (August, 2011) https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf

2 Berkeley National Laboratory, Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning (August, 2016) https://emp.lbl.gov/sites/all/files/lbnl-1006047.pdf

RESPONSE:

The 2018 Peak Load Incremental Loss (PLIL) factors are developed using the attached spreadsheet. These factors are summarized in "Table 4" of the "PLIL" tab of the spreadsheet.

BC Hydro
Power smart

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

8.0 B. ECONOMIC ANALYSIS

Reference: WIND PRICE ESTIMATES
Exhibit B-5, BCUC IR 18.1, 18.1.1; Exhibit B-5-1, BCUC IR 8.1; RAP, Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements, 2011, p. 5;[1] Berkeley National Laboratory, Planning for a distributed disruption, 2016, pp. 59, 60;[2] BC Hydro SOP 2-Year Review, p. 13
Losses adjustment – methodology

BC Hydro provides its updated Peak Load Incremental losses for the Bulk Transmission system in BCUC IR 18.1, loss estimates in Tab 'input losses' in the spreadsheet provided in a confidential response to BCUC IR 8.1, and describes in BCUC IR 18.1.1 its methodology to calculate energy losses. A RAP 2011 paper titled "Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements" uses as a rule of thumb that marginal losses are about 1.5 times average losses.

Berkeley National Laboratory 2016 paper titled: "Planning for a distributed disruption: innovative practices for incorporating distributed solar into utility planning" states that the most comprehensive evaluation of system losses is a time-differentiated marginal loss rate and that Arizona, for example, applies a separate loss rate for each month while the California Public Utilities Commission (CPUC) provides time-differentiated "peak" and "energy" loss rates for each of its investor-owned utilities to apply to estimate the avoided cost of losses for demand-side measures.

The BC Hydro SOP 2-year review includes regional loss adjusters (original and updated) on page 13 of the SOP 2-Year review, and states that losses from the Peace Region have decreased from 13.7 per cent to 6.9 per cent, primarily due to lower system demand.

2.8.2 Please reproduce Table 4.5 of the SOP 2-Year review, including an additional column which shows the 2018 updated energy losses (based on the 2018 Peak Load Incremental Losses). Please show the percentage point difference between the revised

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1 RAP, Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements (August, 2011) https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf

2 Berkeley National Laboratory, Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning (August, 2016) https://emp.lbl.gov/sites/all/files/lbnl-1006047.pdf

SOP losses in the 2-Year Review and 2018 update, and explain any significant difference.

RESPONSE:

The information requested is provided in the table below:

Table 4-5 SOP 2 Year Review (Jan 2011) – Losses (signs reversed to align with the 2018 update)				**2018 Updated Energy Losses**	
Region		**Original (%)**	**Updated (%)**	**From Region to LM**	**Percent Energy Losses (%)**
Vancouver Island	**VI**	**5.7**	**-0.2**	**VI-LM**	**-0.45**
Lower Mainland	**LM**	**6.1**	**-1.8**	**LM-LM**	**0.0**
Kelly/Nicola	**KN**	**5.3**	**5.3**	**KLY-LM** **NIC-LM**	**4.79** **4.31**
Central Interior	**CI**	**6.9**	**2.3**	**CI-LM**	**8.92**
Peace Region	**PR**	**13.7**	**6.9**	**PR-LM**	**14.48**
North Coast	**NC**	**13.2**	**5.8**	**NC-LM**	**8.46**
South Interior	**SI**	**11.3**	**2.5**	**SEL-LM**	**6.61**
East Kootenay	**EK**	**7.0**	**-1.0**	**EK-LM**	**5.30**

The loss numbers in the 2011 SOP 2 Year Review and the 2018 Energy Update are developed using two different approaches, and providing the difference between these two outputs is not meaningful.

In the 2 Year review, power flow base cases for individual distribution connected and transmission connected IPPs were developed. Using these base cases, each IPP was studied separately at its designated in-service year and based on the latest available load forecast at the time. The regional losses were defined as the sum of the energy losses of the Clean Power Call proposals (both distribution connected and transmission connected projects) in each region divided by the sum of their total annual energy. This is considered a reasonable approach when there are a limited number of IPPs and individual custom-made simulations are practical.

The 2018 Update of energy losses was not to target any particular IPPs. Instead, a fictitious 200 MW load was added to a Lower Mainland transmission bus and a fictitious generator was added to a transmission bus at the sending-end region. The difference in the system energy losses before and after these additions was attributed to the transfer of power from the sending region to the Lower Mainland. Energy losses were expressed as a percentage of the total expected energy of the fictitious generator. This approach is a reasonable approximation of energy losses when there are many IPPs and individual power flow simulations are not practical.

8.0 B. ECONOMIC ANALYSIS

Reference: WIND PRICE ESTIMATES
Exhibit B-5, BCUC IR 18.1, 18.1.1; Exhibit B-5-1, BCUC IR 8.1; RAP, Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements, 2011, p. 5;[1] Berkeley National Laboratory, Planning for a distributed disruption, 2016, pp. 59, 60;[2] BC Hydro SOP 2-Year Review, p. 13
Losses adjustment – methodology

BC Hydro provides its updated Peak Load Incremental losses for the Bulk Transmission system in BCUC IR 18.1, loss estimates in Tab 'input losses' in the spreadsheet provided in a confidential response to BCUC IR 8.1, and describes in BCUC IR 18.1.1 its methodology to calculate energy losses. A RAP 2011 paper titled "Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements" uses as a rule of thumb that marginal losses are about 1.5 times average losses.

Berkeley National Laboratory 2016 paper titled: "Planning for a distributed disruption: innovative practices for incorporating distributed solar into utility planning" states that the most comprehensive evaluation of system losses is a time-differentiated marginal loss rate and that Arizona, for example, applies a separate loss rate for each month while the California Public Utilities Commission (CPUC) provides time-differentiated "peak" and "energy" loss rates for each of its investor-owned utilities to apply to estimate the avoided cost of losses for demand-side measures.

The BC Hydro SOP 2-year review includes regional loss adjusters (original and updated) on page 13 of the SOP 2-Year review, and states that losses from the Peace Region have decreased from 13.7 per cent to 6.9 per cent, primarily due to lower system demand.

2.8.2 Please reproduce Table 4.5 of the SOP 2-Year review, including an additional column which shows the 2018 updated energy losses (based on the 2018 Peak Load Incremental Losses). Please show the percentage point difference between the revised

---

[1] RAP, Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements (August, 2011) https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf

[2] Berkeley National Laboratory, Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning (August, 2016) https://emp.lbl.gov/sites/all/files/lbnl-1006047.pdf

SOP losses in the 2-Year Review and 2018 update, and explain any significant difference.

2.8.2.1 To the extent that the methodology described in response to BCUC IR 18.1.1 is different from, (i) that described in the SOP 2-Year review, and (ii) a time-differentiated marginal loss rate, please explain why and provide (in a format consistent with Table 2.5 of the SOP 2-Year Review) BC Hydro's best estimate of what the 2018 regional losses would be using the alternative methodology.

RESPONSE:

The methodology described in response to BCUC IR 1.18.1.1 describes how BC Hydro calculates Peak Load Incremental Losses (PLIL) between different regions of BC Hydro's transmission grid. This methodology was also used in 2018 for updating of regional losses.

The PLIL approach produces results which are different from the SOP 2-Year Review Losses. The difference can be attributed to the following factors:

- **Number of IPPs: The SOP 2-Year Review represent a limited number of IPPs with designated output capacities and expected in-service years. These IPPs were studied using individual custom-made power flow cases. The PLIL is a more generic approach which applies to a large number of generators when their capacities and in-service years are not known. For these generators custom-made modeling is not practical;**
- **Interconnection Voltage: The SOP 2-Year Review IPPs were connected to both Transmission and Distribution voltages. The distribution connected ones represented both T and D losses. The PLIL generators were connected to transmission voltages and represent only T losses;**
- **IPP Location: The SOP 2-Year Review IPPs are individually studied but the regional losses were defined as the sum of the energy losses of the Clean Power Call projects in each region divided by the sum of their total annual energy. The PLIL numbers are based on one generator interconnection located within each region;**
- **Study Year: The SOP 2-Year Review numbers were developed for the in-service year of individual IPPs. The 2018 PLIL numbers represented the fiscal 2025 losses; and**

- **Load Forecast: The SOP 2-Year Review numbers were developed in 2011 using the latest load forecast available at the time. The 2018 PLIL numbers used the May 2016 load forecast.**

As explained here and also in BC Hydro's response to BCUC IR 2.8.2, these two loss evaluation approaches are appropriate for their use and their circumstance. Differences between their results are to be expected.

In the past, BC Hydro has not used a time differential marginal loss rate for evaluating or approximating IPP losses. Consequently, comparison of the 2018 PLIL results with the results of a time differential method is not feasible.

9.0 B. ECONOMIC ANALYSIS

Reference: WIND PRICE ESTIMATES
Exhibit B-5, BCUC IR 21.4; SOP 2-Year Review, p. 9
Shape Adjustment

BC Hydro includes a Time of Delivery table (with monthly peak and off-peak weightings) on page 9 of the SOP 2-year review. BC Hydro provides in response to BCUC IR 21.4 a monthly energy profile for the weighted average of the wind options included in BC Hydro's Site C AdjUEC spreadsheet.

2.9.1 Does BC Hydro consider it reasonable, when using the NERL levelized cost of wind to estimate the value of energy delivered under an EPA, to adjust the levelized cost for differences in energy shape? Please explain.

RESPONSE:

Yes, it is reasonable to adjust the levelized cost of resource options to reflect differences in energy shape.

In order to provide a meaningful evaluation of cost-effectiveness between alternatives, it is necessary to compare resource options (such as run of river hydro and wind) on a similar basis by reflecting differences (including energy profile and location) that impact the value that those options have, in meeting BC Hydro's system need, and on the market. It is BC Hydro's view that using market-based factors is reasonable for providing such an indicative adjustment because they reflect general trends in the value of energy that are common between the system and the market.

BC Hydro notes that these adjustments do not capture other differences in energy profile such as the high short-term variability of wind.

9.0 B. ECONOMIC ANALYSIS

Reference: WIND PRICE ESTIMATES
Exhibit B-5, BCUC IR 21.4; SOP 2-Year Review, p. 9
Shape Adjustment

BC Hydro includes a Time of Delivery table (with monthly peak and off-peak weightings) on page 9 of the SOP 2-year review. BC Hydro provides in response to BCUC IR 21.4 a monthly energy profile for the weighted average of the wind options included in BC Hydro's Site C AdjUEC spreadsheet.

2.9.1 Does BC Hydro consider it reasonable, when using the NERL levelized cost of wind to estimate the value of energy delivered under an EPA, to adjust the levelized cost for differences in energy shape? Please explain.

2.9.1.1 Does BC Hydro consider it reasonable to use the weightings included in the Delivery Price Adjustment Table to make this shape adjustment? Please explain.

RESPONSE:

BC Hydro understands that the "Delivery Price Adjustment Table" in the question and the "Time of Delivery table" in the preamble to be the monthly "Off-Peak" and "On-Peak" values provided for the Clean Power Call in Table 4-1 of the SOP 2-Year Review.

BC Hydro is of the view that for adjusting the levelized cost of wind, the time of delivery weightings provided in the table below are more appropriate to use than the weightings provided in the Delivery Price Adjustment Table because they are consistent with BC Hydro's ABB Fall 2017 Reference Case market price forecast. BC Hydro notes that these adjustments do not reflect any adjustments for short-term wind variability.

BC Hydro also notes that for the purposes of evaluating the cost-effectiveness of the three EPA renewals in the Application, we used the Delivery Price Adjustment Table. For all of the three EPA renewals, using the weighting values from the table below would not have changed the outcome of the cost-effectiveness analysis in the Application.

Table 1 Time of Delivery Table (ABB Fall 2017 Reference Case)

	Peak	Off Peak
Jan	**117**	**107**
Feb	**99**	**99**
Mar	**92**	**95**
Apr	**70**	**82**
May	**63**	**77**
Jun	**81**	**84**
Jul	**107**	**97**
Aug	**129**	**107**
Sep	**113**	**97**
Oct	**111**	**99**
Nov	**115**	**104**
Dec	**128**	**115**

10.0 B. ECONOMIC ANALYSIS

Reference: CAPACITY BENEFITS
Exhibit B-5, BCUC IR 20.1, 20.2, 11.2.2.1; Exhibit B-5-1, BCUC IR 30.3, Attachment 1; Exhibit B-1-1-2, Appendix B, p. 16; Exhibit B-7. CEC IR 5.4;
Site C Inquiry Report, Appendix C, p. 2
General

BC Hydro states in BCUC IR 20.1 that, on a portfolio basis, BC Hydro recognizes the benefits of aggregating wind resource with system capacity using Effective Load Carrying Capability. BC Hydro states in BCUC IR 20.2 that $0/kW-year is a reasonable surplus capacity value, and the Appendix B (Table 3-11) of the Application estimates the capacity value when BC Hydro does not have surplus capacity. Table 3-11 of Appendix B provides the following capacity values: $50-$55/kW-year (F2013$) from F2020 to F2028 (based on Revelstoke Unit 6), and $117/kW-year (F2016$) for F2029 and beyond (based on a simple-cycle gas turbine).

BC Hydro provides its peak capacity resource balance in response to BCUC IR 11.2.2.1. BC Hydro states in response to CEC IR 5.4 that only the Brown Lake EPA renewal contributes to BC Hydro's peak capacity requirements and could be attributed any capacity value.

The Site C Inquiry Report, when removing Site C capacity from the capacity load resource balance, made a downward adjustment to take account of the 14 per cent of supply requiring reserves.

2.10.1 Please update the peak capacity load resource balance after planned resources to exclude the capacity from planned (but not committed) resources that BC Hydro considers could reasonably be displaced by capacity from EPAs included in this Application. Please identify the date that BC Hydro is expected to no longer be in a long-term capacity surplus situation under the, (i) mid-load forecast, ii) high load forecast, and (iii) low load forecast as provided in the spreadsheet in BCUC IR 11.3 Tab BCUC_1_011_02_2_1_ATT Table 4.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.24.1.1.

10.0 B. ECONOMIC ANALYSIS

Reference: CAPACITY BENEFITS
Exhibit B-5, BCUC IR 20.1, 20.2, 11.2.2.1; Exhibit B-5-1, BCUC IR 30.3, Attachment 1; Exhibit B-1-1-2, Appendix B, p. 16; Exhibit B-7. CEC IR 5.4;
Site C Inquiry Report, Appendix C, p. 2
General

BC Hydro states in BCUC IR 20.1 that, on a portfolio basis, BC Hydro recognizes the benefits of aggregating wind resource with system capacity using Effective Load Carrying Capability. BC Hydro states in BCUC IR 20.2 that $0/kW-year is a reasonable surplus capacity value, and the Appendix B (Table 3-11) of the Application estimates the capacity value when BC Hydro does not have surplus capacity. Table 3-11 of Appendix B provides the following capacity values: $50-$55/kW-year (F2013$) from F2020 to F2028 (based on Revelstoke Unit 6), and $117/kW-year (F2016$) for F2029 and beyond (based on a simple-cycle gas turbine).

BC Hydro provides its peak capacity resource balance in response to BCUC IR 11.2.2.1. BC Hydro states in response to CEC IR 5.4 that only the Brown Lake EPA renewal contributes to BC Hydro's peak capacity requirements and could be attributed any capacity value.

The Site C Inquiry Report, when removing Site C capacity from the capacity load resource balance, made a downward adjustment to take account of the 14 per cent of supply requiring reserves.

2.10.1 Please update the peak capacity load resource balance after planned resources to exclude the capacity from planned (but not committed) resources that BC Hydro considers could reasonably be displaced by capacity from EPAs included in this Application. Please identify the date that BC Hydro is expected to no longer be in a long-term capacity surplus situation under the, (i) mid-load forecast, ii) high load forecast, and (iii) low load forecast as provided in the spreadsheet in BCUC IR 11.3 Tab BCUC_1_011_02_2_1_ATT Table 4.

2.10.1.1 Please explain whether an adjustment to account for 14 per cent of supply requiring reserves is required to be made to the resultant capacity load resource balance.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.24.1.1 for why the peak capacity LRB is not updated.

10.0 B. ECONOMIC ANALYSIS

Reference: CAPACITY BENEFITS
Exhibit B-5, BCUC IR 20.1, 20.2, 11.2.2.1; Exhibit B-5-1, BCUC IR 30.3, Attachment 1; Exhibit B-1-1-2, Appendix B, p. 16; Exhibit B-7. CEC IR 5.4;
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BC Hydro provides its peak capacity resource balance in response to BCUC IR 11.2.2.1. BC Hydro states in response to CEC IR 5.4 that only the Brown Lake EPA renewal contributes to BC Hydro's peak capacity requirements and could be attributed any capacity value.

The Site C Inquiry Report, when removing Site C capacity from the capacity load resource balance, made a downward adjustment to take account of the 14 per cent of supply requiring reserves.

2.10.1 Please update the peak capacity load resource balance after planned resources to exclude the capacity from planned (but not committed) resources that BC Hydro considers could reasonably be displaced by capacity from EPAs included in this Application. Please identify the date that BC Hydro is expected to no longer be in a long-term capacity surplus situation under the, (i) mid-load forecast, ii) high load forecast, and (iii) low load forecast as provided in the spreadsheet in BCUC IR 11.3 Tab BCUC_1_011_02_2_1_ATT Table 4.

2.10.1.2 Please estimate how these dates would be affected if BC Hydro undertook cost-effective capacity focused DSM as a first step in addressing the capacity shortfall. Please explain.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.24.1.1 for why the peak capacity LRB is not updated.

As described in the Site C Inquiry, BC Hydro has determined that approximately 85 MW of load curtailment could be relied upon for planning purposes.

BC Hydro is currently undertaking pilots and trials to investigate the potential of capacity-focused DSM, but this activity is not yet fully complete. Continuation and completion of planned trials, as well as further experience gained through localized capacity initiatives at the substation level are the next steps prior to estimating overall savings potential. BC Hydro expects the results of the pilots and trials to inform the capacity resource options in the next IRP.

10.0 B. ECONOMIC ANALYSIS

Reference: CAPACITY BENEFITS
Exhibit B-5, BCUC IR 20.1, 20.2, 11.2.2.1; Exhibit B-5-1, BCUC IR 30.3, Attachment 1; Exhibit B-1-1-2, Appendix B, p. 16; Exhibit B-7. CEC IR 5.4;
Site C Inquiry Report, Appendix C, p. 2
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BC Hydro states in BCUC IR 20.1 that, on a portfolio basis, BC Hydro recognizes the benefits of aggregating wind resource with system capacity using Effective Load Carrying Capability. BC Hydro states in BCUC IR 20.2 that $0/kW-year is a reasonable surplus capacity value, and the Appendix B (Table 3-11) of the Application estimates the capacity value when BC Hydro does not have surplus capacity. Table 3-11 of Appendix B provides the following capacity values: $50-$55/kW-year (F2013$) from F2020 to F2028 (based on Revelstoke Unit 6), and $117/kW-year (F2016$) for F2029 and beyond (based on a simple-cycle gas turbine).

BC Hydro provides its peak capacity resource balance in response to BCUC IR 11.2.2.1. BC Hydro states in response to CEC IR 5.4 that only the Brown Lake EPA renewal contributes to BC Hydro's peak capacity requirements and could be attributed any capacity value.

The Site C Inquiry Report, when removing Site C capacity from the capacity load resource balance, made a downward adjustment to take account of the 14 per cent of supply requiring reserves.

2.10.2 Please explain whether there are any restrictions preventing BC Hydro from relying on a gas turbine for new capacity, and what a comparable cost (in $/kW-year) of clean capacity would be.

RESPONSE:

There are no prohibitions that altogether prevent BC Hydro from relying on a gas turbine for new capacity; however, BC Hydro recognizes there would be challenges to obtain the necessary permits. In addition, the 93 per cent clean or renewable target set out in the Clean Energy Act limits the reliance on gas-fired generation. Reliance on gas turbines for new capacity would also be inconsistent with the Government Mandate Letter to BC Hydro dated February 21, 2019, stating:

> **"Our new climate strategy will outline significant GHG reduction measures in 2019/20 while supporting our program and service objectives through economic growth powered by clean, renewable energy, supported by technological innovation. Please ensure your organization's operations align with Government's new climate plan."**

Clean capacity generation options beyond Revelstoke Unit 6 could be pumped storage. The fixed cost of pumped storage is estimated to be $108/kW-year. BC Hydro is in the process of updating its assessment of the operating regime required of pumped storage as a capacity resource. Pumped storage units are a net consumer of energy during operation due to losses associated with pump-generate cycle. The cost associated with the losses during operations and other variable costs would add to the unit capacity cost.

10.0 B. ECONOMIC ANALYSIS

Reference: CAPACITY BENEFITS
Exhibit B-5, BCUC IR 20.1, 20.2, 11.2.2.1; Exhibit B-5-1, BCUC IR 30.3, Attachment 1; Exhibit B-1-1-2, Appendix B, p. 16; Exhibit B-7. CEC IR 5.4;
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BC Hydro provides its peak capacity resource balance in response to BCUC IR 11.2.2.1. BC Hydro states in response to CEC IR 5.4 that only the Brown Lake EPA renewal contributes to BC Hydro's peak capacity requirements and could be attributed any capacity value.

The Site C Inquiry Report, when removing Site C capacity from the capacity load resource balance, made a downward adjustment to take account of the 14 per cent of supply requiring reserves.

2.10.3 Does BC Hydro consider that it is reasonable to ignore capacity benefits when evaluating the cost-effectiveness of an EPA, where, (i) BC Hydro is in an energy and capacity shortage situation, and (ii) the effective load carrying capability of wind generation (when used to value the EPA's energy) is similar to or greater than the effective load carrying capacity of energy delivered under the EPA? Please explain.

RESPONSE:

BC Hydro considers dependable capacity and not Effective Load Carrying Capability (ELCC) when evaluating the cost-effectiveness of an individual EPA.

Dependable capacity is not equivalent to ELCC. ELCC is relevant for portfolio analysis of alternatives to meeting system needs; however, it is not appropriate to

use when evaluating individual projects that do not, on their own, contribute dependable capacity. Although individual projects such as wind and run of river hydro facilities may contribute to increasing BC Hydro's system ELCC, it is the aggregation with BC Hydro's system that provides these ELCC benefits.

BC Hydro notes that ELCC is not directly related to a project's annual energy contributions.

BC Hydro also notes that, of the three EPA renewals in the Application only the Brown Lake facility would provide dependable capacity. However, the dependable capacity benefits were not included in the assessment of the cost-effectiveness of the Brown Lake EPA renewal because the EPA price was already lower than BC Hydro's opportunity cost as filed in the Application prior to the inclusion of a capacity benefit.

10.0 B. ECONOMIC ANALYSIS

Reference: CAPACITY BENEFITS
Exhibit B-5, BCUC IR 20.1, 20.2, 11.2.2.1; Exhibit B-5-1, BCUC IR 30.3, Attachment 1; Exhibit B-1-1-2, Appendix B, p. 16; Exhibit B-7. CEC IR 5.4;
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BC Hydro provides its peak capacity resource balance in response to BCUC IR 11.2.2.1. BC Hydro states in response to CEC IR 5.4 that only the Brown Lake EPA renewal contributes to BC Hydro's peak capacity requirements and could be attributed any capacity value.

The Site C Inquiry Report, when removing Site C capacity from the capacity load resource balance, made a downward adjustment to take account of the 14 per cent of supply requiring reserves.

2.10.3 Does BC Hydro consider that it is reasonable to ignore capacity benefits when evaluating the cost-effectiveness of an EPA, where, (i) BC Hydro is in an energy and capacity shortage situation, and (ii) the effective load carrying capability of wind generation (when used to value the EPA's energy) is similar to or greater than the effective load carrying capacity of energy delivered under the EPA? Please explain.

2.10.3.1 Please provide, in table form, the Effective Load Carrying Capability for each EPA (in kW), and the Effective Load Carrying Capability of a portfolio of wind projects (in kW) sized to generate the same amount of annual energy as generated by the EPA. For the portfolio wind, assume no reduction in load carrying capability from the resizing.

RESPONSE:

The requested table is provided below. Please refer to BC Hydro's response to BCUC IR 2.10.3 for a discussion of why BC Hydro does not believe it is appropriate to compare the effective load carrying capability (ELCC) contributions of resources in evaluating the cost-effectiveness of EPA renewals.

Table 1 Comparison of ELCC for EPA Renewals and Equivalent Typical Wind (kW)

	EPA Renewals	Equivalent Typical Wind
Sechelt Creek	**4,450**	**5,580**
Brown Lake	**4,274**	**3,450**
Walden North	**1,495**	**3,113**
Total	**10,219**	**12,143**

10.0 B. ECONOMIC ANALYSIS

Reference: CAPACITY BENEFITS
Exhibit B-5, BCUC IR 20.1, 20.2, 11.2.2.1; Exhibit B-5-1, BCUC IR 30.3, Attachment 1; Exhibit B-1-1-2, Appendix B, p. 16; Exhibit B-7. CEC IR 5.4;
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BC Hydro provides its peak capacity resource balance in response to BCUC IR 11.2.2.1. BC Hydro states in response to CEC IR 5.4 that only the Brown Lake EPA renewal contributes to BC Hydro's peak capacity requirements and could be attributed any capacity value.

The Site C Inquiry Report, when removing Site C capacity from the capacity load resource balance, made a downward adjustment to take account of the 14 per cent of supply requiring reserves.

2.10.3 Does BC Hydro consider that it is reasonable to ignore capacity benefits when evaluating the cost-effectiveness of an EPA, where, (i) BC Hydro is in an energy and capacity shortage situation, and (ii) the effective load carrying capability of wind generation (when used to value the EPA's energy) is similar to or greater than the effective load carrying capacity of energy delivered under the EPA? Please explain.

2.10.3.2 For each EPA, please explain whether BC Hydro considers a capacity credit should be included in its economic evaluation, and if yes, for which years, for what amount (in kW), and how it should be valued (in $/kW-year). Please adjust for 2018 peak capacity loss factors, and include supporting analysis and assumptions.

RESPONSE:

The public version of this response has been redacted to maintain in confidence commercially sensitive information as public disclosure could prejudice BC Hydro's negotiating position and commercial interests with respect to other EPAs.

As discussed in BC Hydro's response to BCUC IR 2.10.3, BC Hydro only considers a capacity credit would be applicable to the Brown Lake EPA. In BC Hydro's response to BCUC IR 1.8.1, we indicated that the Brown Lake hydro facility is estimated to provide 6 MW of dependable capacity and reflecting the long term value of this capacity would increase BC Hydro's opportunity costs by approximately $[redacted]-$[redacted]/MWh. This range included an adjustment for the peak loss factors set out Attachment 1 to BC Hydro's response to BCUC IR 1.8.1 (please refer to column E in the "Input_Losses" worksheet of Attachment 1).

Using the 2018 peak loss factors, these values would reduce the capacity credit to $[redacted]-$[redacted]/MWh. Please refer to Attachment 1 of BC Hydro's response to BCUC CONF IR 2.9.1 for the supporting analysis and assumptions.

11.0 C. ENGINEERING AND ENERGY RELIABILITY
Reference: IPP DECOMMISSIONING – DECOMMISSIONING AND ENERGY RELIABILITY
Exhibit B-5, BCUC IR 3.3.1
Decommissioning Obligation and Scope of Work

In response to BCUC IR 3.3.1, BC Hydro states:

Further, plant decommissioning is an intensive process, involving the removal of substantial amounts of concrete, steel and other project works requiring the use of heavy machinery

Further in response to BCUC IR 3.4, BC Hydro states:

If the Sechelt Creek IPP facility were to be decommissioned, BC Hydro bears no legal obligation for mitigating any potential impacts associated with the Sechelt Creek facility.

2.11.1 In absence of an EPA, please confirm that BC Hydro bears no legal responsibility for the decommissioning or any potential impacts related to decommissioning for the Sechelt Creek, Brown Lake and Walden North facilities.

RESPONSE:

BC Hydro confirms that in the absence of an EPA BC Hydro bears no legal responsibility for the decommissioning or any potential impacts related to decommissioning for the Sechelt Creek or Brown Lake facilities.

BC Hydro notes that should the Walden North IPP be decommissioned, it would impact BC Hydro's works in relation to the Cayoosh Diversion Tunnel and our management of the dilution ratio required for salmon migration. BC Hydro has not assessed whether it might bear some legal responsibility in relation to the decommissioning of the Walden North IPP and potential impacts in relation to the diversion tunnel. Please also refer to BC Hydro's response to BCUC IR 1.5.1.

11.0 C. ENGINEERING AND ENERGY RELIABILITY
Reference: IPP DECOMMISSIONING – DECOMMISSIONING AND ENERGY RELIABILITY
Exhibit B-5, BCUC IR 3.3.1
Decommissioning Obligation and Scope of Work

In response to BCUC IR 3.3.1, BC Hydro states:

Further, plant decommissioning is an intensive process, involving the removal of substantial amounts of concrete, steel and other project works requiring the use of heavy machinery

Further in response to BCUC IR 3.4, BC Hydro states:

If the Sechelt Creek IPP facility were to be decommissioned, BC Hydro bears no legal obligation for mitigating any potential impacts associated with the Sechelt Creek facility.

2.11.2 In absence of an EPA, does BC Hydro anticipate capital asset additions to heritage assets if the Sechelt Creek, Brown Lake and Walden North facilities are decommissioned? If so, please provide a detailed scope of work, associated costs and possible impact on ratepayers.

RESPONSE:

BC Hydro notes that from a resource planning perspective, it is the existence (or lack of existence) of the EPA which has a potential impact to BC Hydro; the potential decommissioning of the facility does not itself impact our resource stack. BC Hydro has not assessed what the impact of not having these EPAs would be on future capital asset additions and heritage assets. Evaluation of alternatives - which also include DSM alternatives, EPA renewals, and investments in heritage assets - for meeting BC Hydro's supply obligations and other objectives are considered at the portfolio level in our IRP.

Please also refer to BC Hydro's response to BCUC IR 2.24.1.1.

12.0 C. ENGINEERING AND ENERGY RELIABILITY
Reference: BC HYDRO AND IPP ALTERNATIVE RELIABILITY AGREEMENTS
Exhibit B-5, BCUC IR 38.3
EPA Alternatives

In response to BCUC IR 38.3, BC Hydro states:

In the absence of this Brown Lake EPA renewal, BC Hydro would consider an alternative agreement if it makes economic sense for the Brown Lake IPP to provide reliability services to BC Hydro.

2.12.1 Does Sechelt Creek Hydro, Brown Lake Hydro and Walden North Hydro, respectively, provide further ancillary reliability benefits, such as frequency or voltage-VAR control, to the BC Hydro system? If so, please provide a description and quantify these additional reliability services.

RESPONSE:

Other than the reliability benefits and dependable capacity benefits provided by the Brown Lake IPP, no further ancillary reliability benefits from the Sechelt Creek, Brown Lake and Walden North facilities have been quantified as providing material benefits to the BC Hydro system. Please refer to BC Hydro's response to BCUC IR 2.10.3 for information regarding the dependable capacity and BCUC IR 2.14.4 for information regarding the unplanned outage frequency and duration of 2L101 where reliability benefits are provided by the Brown Lake facility.

12.0 C. ENGINEERING AND ENERGY RELIABILITY
Reference: BC HYDRO AND IPP ALTERNATIVE RELIABILITY AGREEMENTS
Exhibit B-5, BCUC IR 38.3
EPA Alternatives

In response to BCUC IR 38.3, BC Hydro states:

In the absence of this Brown Lake EPA renewal, BC Hydro would consider an alternative agreement if it makes economic sense for the Brown Lake IPP to provide reliability services to BC Hydro.

2.12.1 Does Sechelt Creek Hydro, Brown Lake Hydro and Walden North Hydro, respectively, provide further ancillary reliability benefits, such as frequency or voltage-VAR control, to the BC Hydro system? If so, please provide a description and quantify these additional reliability services.

2.12.1.1 In the absence of the EPAs, does BC Hydro have alternative resources that can provide equivalent ancillary reliability services from the IPPs? If so, please provide a description and possible associated costs.

RESPONSE:

Please refer to BC Hydro's responses to BCUC IRs 2.12.1 and the 2.14 series.

12.0 C. ENGINEERING AND ENERGY RELIABILITY
Reference: BC HYDRO AND IPP ALTERNATIVE RELIABILITY AGREEMENTS
Exhibit B-5, BCUC IR 38.3
EPA Alternatives

In response to BCUC IR 38.3, BC Hydro states:

In the absence of this Brown Lake EPA renewal, BC Hydro would consider an alternative agreement if it makes economic sense for the Brown Lake IPP to provide reliability services to BC Hydro.

2.12.2 In the absence of the EPAs, please provide a detailed description of the possible alternative agreements BC Hydro may explore with Sechelt Creek Hydro, Brown Lake Hydro or Walden North Hydro. Further, please provide approximate costs with respect to each possible alternative agreement based on similar historical BC Hydro agreements.

RESPONSE:

BC Hydro has not undertaken an assessment of what other possible alternative agreements we may wish to explore with each of the IPPs if the renewal EPAs are not accepted by the BCUC. However, as noted in BC Hydro's response to BCUC IR 1.38.3, in the absence of the Brown Lake EPA renewal, BC Hydro may wish to obtain reliability services from the Brown Lake IPP if it makes economic sense to do so. In addition, as discussed in BC Hydro's response to BCUC IR 1.5.1 with respect to the Walden North IPP, BC Hydro would need to consider available options for building an alternative diversion structure if the Walden North Diversion Agreement no longer continues.

12.0 C. ENGINEERING AND ENERGY RELIABILITY
Reference: BC HYDRO AND IPP ALTERNATIVE RELIABILITY AGREEMENTS
Exhibit B-5, BCUC IR 38.3
EPA Alternatives

In response to BCUC IR 38.3, BC Hydro states:

In the absence of this Brown Lake EPA renewal, BC Hydro would consider an alternative agreement if it makes economic sense for the Brown Lake IPP to provide reliability services to BC Hydro.

2.12.2 In the absence of the EPAs, please provide a detailed description of the possible alternative agreements BC Hydro may explore with Sechelt Creek Hydro, Brown Lake Hydro or Walden North Hydro. Further, please provide approximate costs with respect to each possible alternative agreement based on similar historical BC Hydro agreements.

2.12.2.1 With respect to each possible alternative agreement, please indicate whether the energy reliability benefits, such as local standby generation or low transmission losses, submitted in the Application are retained.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.12.2.

13.0 C. ENGINEERING AND ENERGY RELIABILITY
Reference: SECHELT CREEK IPP – ENERGY RELIABILITY
Exhibit B-5, BCUC IR 35.1
Energy Resourcing and Transmission Losses

In response to BCUC IR 35.1, BC Hydro submits the following information on energy resourcing and transmission losses from the Sechelt Creek IPP:

As is the case for the majority of BC Hydro's resources, the Sechelt Creek IPP does not provide energy to a specific BC Hydro load. However, it is close to BC Hydro's load centre in the Lower Mainland and this proximity is beneficial as this means there will be fewer losses on the system.

If BC Hydro does not receive energy from the Sechelt Creek IPP, energy will be provided to BC Hydro's load centre by other existing and future resources. While this would be technically viable, other future resources may not be as cost effective as this EPA renewal.

2.13.1 Please provide the annual quantity of energy Sechelt Creek IPP has delivered to local load centers (Lower Mainland) in GWh, and as a percent of total energy output over the last four years.

RESPONSE:

The Sechelt Creek hydro project has an average annual generation of 85 GWh. This generation is injected into the BC Hydro integrated system, and the specific amount of total output that is delivered to Lower Mainland is not measured. However, the Sechelt Creek hydro project transmission losses are relatively low due to its proximity to the Lower Mainland load centre.

13.0 C. ENGINEERING AND ENERGY RELIABILITY
Reference: SECHELT CREEK IPP – ENERGY RELIABILITY
Exhibit B-5, BCUC IR 35.1
Energy Resourcing and Transmission Losses

In response to BCUC IR 35.1, BC Hydro submits the following information on energy resourcing and transmission losses from the Sechelt Creek IPP:

As is the case for the majority of BC Hydro's resources, the Sechelt Creek IPP does not provide energy to a specific BC Hydro load. However, it is close to BC Hydro's load centre in the Lower Mainland and this proximity is beneficial as this means there will be fewer losses on the system.

If BC Hydro does not receive energy from the Sechelt Creek IPP, energy will be provided to BC Hydro's load centre by other existing and future resources. While this would be technically viable, other future resources may not be as cost effective as this EPA renewal.

2.13.2 In absence of EPA, please provide the likely BC Hydro alternative energy resources that will substitute the energy from Sechelt Creek IPP to the Lower Mainland?

RESPONSE:

If the Sechelt Creek project does not receive an EPA, BC Hydro will utilize our heritage resources, other IPP resources, and market as needed to supply load.

13.0 C. ENGINEERING AND ENERGY RELIABILITY
Reference: SECHELT CREEK IPP – ENERGY RELIABILITY
Exhibit B-5, BCUC IR 35.1
Energy Resourcing and Transmission Losses

In response to BCUC IR 35.1, BC Hydro submits the following information on energy resourcing and transmission losses from the Sechelt Creek IPP:

As is the case for the majority of BC Hydro's resources, the Sechelt Creek IPP does not provide energy to a specific BC Hydro load. However, it is close to BC Hydro's load centre in the Lower Mainland and this proximity is beneficial as this means there will be fewer losses on the system.

If BC Hydro does not receive energy from the Sechelt Creek IPP, energy will be provided to BC Hydro's load centre by other existing and future resources. While this would be technically viable, other future resources may not be as cost effective as this EPA renewal.

2.13.3 With respect to the annual energy delivered from the Sechelt Creek IPP to the Lower Mainland over the last four years, please compare the transmission losses, in terms of GWh and cost of energy, between Sechelt Creek IPP and likely BC Hydro alternative energy resources.

RESPONSE:

For the reasons discussed in BC Hydro's response to BCUC IR 2.13.1, we cannot provide the requested comparison. However, Sechelt Creek hydro project transmission losses are relatively low due to its proximity to the Lower Mainland load centre.

14.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: BROWN LAKE IPP – ENERGY RELIABILITY
Exhibit B-5, BCUC IR 37.1
Stand-by Service and Reliability

In response to BCUC IR 37.1, BC Hydro provided the electrical one-line drawing and the generation capacity of local heritage assets and load ranges for the Prince Rupert area:

The BC Hydro transmission line to the Prince Rupert area is 2L101 which runs along the Skeena River…

As shown in the one-line diagram, the Brown Lake IPP (BRL), BC Hydro's Falls River Generating Station (FLS) and BC Hydro's Prince Rupert Generating Station (RPG) are each able to provide local generation to the Prince Rupert area. The installed capacity for these back-up alternatives to the grid power connection are as follows: BRL at 7.2MW, FLS at 7MW, and RPG at 46MW. BC Hydro notes that the historical peak load in the Prince Rupert area generally ranges from 43MW to 48MW.

If the 2L101 transmission line is not available, stand-by service would be available from the Prince Rupert Generating Station (which is a natural gas and diesel generation facility) to the extent that hydro generation from the Falls River Generating facility and the Brown Lake IPP is not sufficient to meet local load requirements.

2.14.1 In the absence of an EPA with Brown Lake IPP, please explain how BC Hydro intends to ensure energy reliability for the Prince Rupert area if transmission line 2L101 is unavailable.

RESPONSE:

If the 2L101 transmission line is not available and in the absence of an EPA with Brown Lake IPP, stand-by service from the Prince Rupert Generating Station would be used to support reliability for the Prince Rupert Area. In general, Prince Rupert Generating Station and Falls River Generating Station are currently able to support local load during an outage on 2L101 and in certain circumstances (e.g., an outage during peak load periods), customers may be asked to manage their load during an extended outage. The ability of Prince Rupert Generating Station and Falls River to ensure reliability in the Prince Rupert Area is expected to diminish as local demand for electricity increases.

14.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: BROWN LAKE IPP – ENERGY RELIABILITY
Exhibit B-5, BCUC IR 37.1
Stand-by Service and Reliability

In response to BCUC IR 37.1, BC Hydro provided the electrical one-line drawing and the generation capacity of local heritage assets and load ranges for the Prince Rupert area:

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If the 2L101 transmission line is not available, stand-by service would be available from the Prince Rupert Generating Station (which is a natural gas and diesel generation facility) to the extent that hydro generation from the Falls River Generating facility and the Brown Lake IPP is not sufficient to meet local load requirements.

2.14.2 Is the Prince Rupert Generating Station (RPG) facility currently operating under its rated capacity? If so, please provide the current operating capacity and explain why it is not operating at its rated capacity.

RESPONSE:

The nominal rated capacity for the plant is 46 MW (2 units x 23 MW) and the plant is operated as required to meet area load. There is no restriction on its rated capacity. However, gas turbine output varies with ambient temperature. The RPG units output can vary from 20 MW (high ambient temperatures) to 27 MW (low ambient temperatures). The nominal 23 MW value is chosen based on average area temperatures.

14.0 C. ENGINEERING AND ENERGY RELIABILITY

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If the 2L101 transmission line is not available, stand-by service would be available from the Prince Rupert Generating Station (which is a natural gas and diesel generation facility) to the extent that hydro generation from the Falls River Generating facility and the Brown Lake IPP is not sufficient to meet local load requirements.

2.14.3 Does BC Hydro anticipate reliability issues with RPG that may force the facility off-line for extended periods or limit its energy output capacity, such as major refurbishment or capital asset plans? If so, please provide a detailed description, risk analysis on energy reliability, and impact on RPG generation.

RESPONSE:

BC Hydro does not anticipate reliability issues that would force the RPG facility off-line for extended periods or limit its energy output capacity, such as major refurbishment or capital asset plans. There is a risk of gas supply interruption in winter and early spring due to landslides or avalanches. In the event of loss of both the gas supply and transmission line, RPG is able to operate on back up supplies of diesel fuel. However, extended islanded operation on diesel fuel may impact energy output as a result of the amount of fuel stored at site and the logistics associated with replenishment.

14.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: BROWN LAKE IPP – ENERGY RELIABILITY
Exhibit B-5, BCUC IR 37.1
Stand-by Service and Reliability

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If the 2L101 transmission line is not available, stand-by service would be available from the Prince Rupert Generating Station (which is a natural gas and diesel generation facility) to the extent that hydro generation from the Falls River Generating facility and the Brown Lake IPP is not sufficient to meet local load requirements.

2.14.4 In table format, please provide the unplanned outage frequency and duration of 2L101 for the last ten years.

RESPONSE:

The table below provides the unplanned outage frequency and duration of 2L101 for the last ten years.

Year	Forced Outages	Forced Outage Duration
2009	**2**	**1 hr 29 min**
2010	**1**	**10hr 26 min**
2011	**6**	**18 hrs 59 min**
2012	**0**	
2013	**1**	**4 min**

Year	Forced Outages	Forced Outage Duration
2014	**0**	
2015	**1**	**10 days 1 hr 45 min**
2016	**3**	**15 hours 2 min**
2017	**1**	**3 hours 25 min**
2018	**1**	**10 days 5 hours 30 min**

14.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: BROWN LAKE IPP – ENERGY RELIABILITY
Exhibit B-5, BCUC IR 37.1
Stand-by Service and Reliability

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As shown in the one-line diagram, the Brown Lake IPP (BRL), BC Hydro's Falls River Generating Station (FLS) and BC Hydro's Prince Rupert Generating Station (RPG) are each able to provide local generation to the Prince Rupert area. The installed capacity for these back-up alternatives to the grid power connection are as follows: BRL at 7.2MW, FLS at 7MW, and RPG at 46MW. BC Hydro notes that the historical peak load in the Prince Rupert area generally ranges from 43MW to 48MW.

If the 2L101 transmission line is not available, stand-by service would be available from the Prince Rupert Generating Station (which is a natural gas and diesel generation facility) to the extent that hydro generation from the Falls River Generating facility and the Brown Lake IPP is not sufficient to meet local load requirements.

2.14.4 In table format, please provide the unplanned outage frequency and duration of 2L101 for the last ten years.

2.14.4.1 Please explain whether the generation capacity of BC Hydro local assets (RPG and Falls River Generating Station (FLS)) fell below the peak loads of the Prince Rupert area during these unplanned outages.

RESPONSE:

The generation capacity of BC Hydro local assets (RPG and Falls River Generating Station (FLS)) did not fall below peak loads of the Prince Rupert area during the unplanned outages. Peak loads for the Prince Rupert area generally occur during November 1 to February 28. There was only one unplanned outage in the last 10 years in 2015 that occurred during the peak load period. The peak load in 2015 was 45 MW which was below the generation capacity of RPG and FLS; however to manage reliability some customers were requested to manage their load during this outage.

14.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: BROWN LAKE IPP – ENERGY RELIABILITY
Exhibit B-5, BCUC IR 37.1
Stand-by Service and Reliability

In response to BCUC IR 37.1, BC Hydro provided the electrical one-line drawing and the generation capacity of local heritage assets and load ranges for the Prince Rupert area:

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2.14.5 Have the historical peak loads of the Prince Rupert area (43MW-48MW) ever exceeded the total generation capacity of local BC Hydro assets (RPG and FLS). If so, please provide the duration, generation deficit, and BC Hydro reliability plans during those periods.

RESPONSE:

The historical peak loads of the Prince Rupert area have not exceeded the total generation capacity of local BC Hydro assets (RPG and FLS).

14.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: BROWN LAKE IPP – ENERGY RELIABILITY
Exhibit B-5, BCUC IR 37.1
Stand-by Service and Reliability

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If the 2L101 transmission line is not available, stand-by service would be available from the Prince Rupert Generating Station (which is a natural gas and diesel generation facility) to the extent that hydro generation from the Falls River Generating facility and the Brown Lake IPP is not sufficient to meet local load requirements.

2.14.6 Please provide a reliability analysis regarding the probability of 2L101 being unavailable and local BC Hydro generation assets (RGP and FLS) failing to meet peak loads in the Prince Rupert area.

RESPONSE:

The Prince Rupert area loads are comprised of distribution substation (D) and transmission voltage customer (T) components. The actual D and T Non-Coincidental Peak (NCP) load in fiscal 2017 was 52.7 MW. The capacities of BRL, FLS and RPG were sufficient to serve the NCP load during a sustained outage of 2L101.

The local BC Hydro generation assets (RGP and FLS) have sufficient capacity to meet historical peak loads ranging from 43 MW to 48 MW during an outage of

2L101. However, the present reliability is expected to diminish as local demand for electricity increases.

Based on the transmission planning standards (TPL) of the North American Electric Reliability Corporation, consequential load losses are allowed following the forced outage of a radial transmission line such as 2L101.

15.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: GENERAL EPA RENEWAL STRATEGY
Exhibit B-5, BCUC IR 42.1.1; Comprehensive Review or BC Hydro: Phase 1 Report[1] (Phase 1 Report), p. 23; Zapped dated February 2019,[2] p. 1
IPP renewal strategy prior to 2021 Integrated Resource Plan (IRP)

BC Hydro states in its response to BCUC IR 42.1.1 that "As stated in BC Hydro's F17-F19 RRA which reflected the most recent load resource balance (LRB) at the time of these EPA renewal negotiations, BC Hydro's plan has been to include pursuing EPA renewals consistent with the 2013 IRP." And that "In addition, the cost of EPA renewals must still be within BC Hydro's budget. For example, the total cost forecast from the 10-Year Rates Plan had been used to provide a financial framework and budget within which to manage the costs for all EPA renewals."

In the February 2019 report titled Zapped by Ken Davidson, it states on page 1 that "[a]s demonstrated in Section 3, over the balance of the term of the Response EPAs, BC Hydro will lose an additional ~$6.8 billion selling energy to ratepayers for rates less than BC Hydro is buying it from IPPs." It further states on page 2 that "there is an opportunity to address these financial issues when the EPAs for IPP projects expire and can be renewed on a commercial and market rate basis."

The Phase 1 Report states on page 23: "Standing Offer Program (SOP) prices currently average $108 per MWh, which is over three times the cost of energy from BC Hydro heritage assets and nearly 75% higher than that of Site C." and that "Standing Offer Program prices are up to nearly five times higher than export market price forecasts."

2.15.1 Please explain whether BC Hydro intends to enter into any additional IPP renewals prior to the completion of the 2021 IRP.

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1 https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/final_report_desktop_bc_hydro_review_v04_feb12_237pm-r2.pdf

2 https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bch19-158-ipp_report_february_11_2019.pdf

RESPONSE:

There are 10 EPAs which are expected to expire prior to BC Hydro's submission of its 2021 IRP by February 28, 2021. The EPAs which are due to expire include:

- **Six biomass EPAs for facilities that are eligible for the Biomass Energy Program[3], which represent a total of 389 MW in capacity;**
- **Two run-of-river hydro EPAs for facilities which represent a total of less than 4 MW in capacity; and**
- **Two EPAs for facilities in the Non-Integrated Area, one of which is the EPA for the Ocean Falls IPP that is due to expire by June 30, 2019 and is a matter currently before the BCUC.**

BC Hydro expects to have EPA renewal agreements with some of these IPPs (and conceivably all) prior to the completion of the 2021 IRP.

As a result of the Phase 1 Report of the Government's Comprehensive Review, for the biomass EPA renewals referenced above, BC Hydro's renewal assumption is 80 per cent of the aggregate historical volumes for Biomass Energy Program eligible facilities. However, with respect to the run-of-river hydro EPA renewals noted above, the 75 per cent renewal assumption of aggregate volume is no longer applicable. This is because BC Hydro recently adopted the use of market price as a conservative interim assumption for evaluating cost-effectiveness of EPAs on the integrated system (other than those for facilities eligible for the Biomass Energy Program or facilities with other benefits) during surplus and deficit periods, and as a result we do not have certainty as to whether the 75 per cent is achievable. With respect to EPA renewals in the Non-Integrated Area, the renewal assumption remains at 100 per cent.

BC Hydro expects that its EPA renewal approach will be revisited as part of the process for the 2021 IRP.

[3] A total of seven facilities are eligible for the Biomass Energy Program, and six of those facilities have EPAs that expire prior to February 2021.

15.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: GENERAL EPA RENEWAL STRATEGY
Exhibit B-5, BCUC IR 42.1.1; Comprehensive Review or BC Hydro: Phase 1 Report[1] (Phase 1 Report), p. 23; Zapped dated February 2019,[2] p. 1
IPP renewal strategy prior to 2021 Integrated Resource Plan (IRP)

BC Hydro states in its response to BCUC IR 42.1.1 that "As stated in BC Hydro's F17-F19 RRA which reflected the most recent load resource balance (LRB) at the time of these EPA renewal negotiations, BC Hydro's plan has been to include pursuing EPA renewals consistent with the 2013 IRP." And that "In addition, the cost of EPA renewals must still be within BC Hydro's budget. For example, the total cost forecast from the 10-Year Rates Plan had been used to provide a financial framework and budget within which to manage the costs for all EPA renewals."

In the February 2019 report titled Zapped by Ken Davidson, it states on page 1 that "[a]s demonstrated in Section 3, over the balance of the term of the Response EPAs, BC Hydro will lose an additional ~$6.8 billion selling energy to ratepayers for rates less than BC Hydro is buying it from IPPs." It further states on page 2 that "there is an opportunity to address these financial issues when the EPAs for IPP projects expire and can be renewed on a commercial and market rate basis."

The Phase 1 Report states on page 23: "Standing Offer Program (SOP) prices currently average $108 per MWh, which is over three times the cost of energy from BC Hydro heritage assets and nearly 75% higher than that of Site C." and that "Standing Offer Program prices are up to nearly five times higher than export market price forecasts."

2.15.2 In light of the findings in the Zapped report and the Phase 1 Report, please explain what is BC Hydro's current IPP renewal strategy going forward, until additional government policy or the BC Hydro 2021 IRP informs further information. Please elaborate on any financial framework used and the quantity of energy BC Hydro anticipates to acquire from any future IPP renewals.

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1 https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/final_report_desktop_bc_hydro_review_v04_feb12_237pm-r2.pdf

2 https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bch19-158-ipp_report_february_11_2019.pdf

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.15.1 for a discussion regarding BC Hydro's current EPA renewal strategy and BCUC IR 2.19.2 with respect to financial framework.

16.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: GENERAL EPA RENEWAL STRATEGY
Exhibit B-5, BCUC IR 42.5; *Utilities Commission Act*, section 71
IPP renewal strategy in upcoming IRP

In response to BCUC IR 42.5, BC Hydro states:

As discussed in BC Hydro's response to BCUC IR 1.9.1, BC Hydro expects to finalize its next IRP by February 28, 2021. At this time, BC Hydro has not scoped out the upcoming IRP. However, we currently do not anticipate that an analysis of energy procurement processes will be carried out in preparation for next IRP and should a need be identified for such an analysis, then this would be part of the development of the IRP following the identification of resource needs.

Section 71(2.21) of the *Utilities Commission Act* (UCA) states "In determining under subsection (2) whether an energy supply contract filed by the authority is in the public interest, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider… (b) an applicable integrated resource plan approved under section 4 of the Clean Energy Act,…"

2.16.1 Please elaborate on the extent and context under which energy purchases from IPPs will be contemplated in the upcoming IRP.

RESPONSE:

The upcoming IRP will develop BC Hydro's strategic direction and near term actions on conservation, electrification, infrastructure investments and the acquisition of energy and capacity resources. The mix of resources to be acquired could include resources such as DSM, purchases from IPPs or other BC Hydro projects, depending on the long-term need for resources and the alignment of these resources with BC Hydro's strategic direction. The context for need and strategic direction would be informed by, among other things, policy such as the CleanBC plan and outcome from the Government Review. Further elaboration on the extent and context under which energy purchases from IPPs will be contemplated in the upcoming IRP is premature at this time, as the scope of the upcoming IRP is currently under development.

16.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: GENERAL EPA RENEWAL STRATEGY
Exhibit B-5, BCUC IR 42.5; *Utilities Commission Act*, section 71
IPP renewal strategy in upcoming IRP

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2.16.2 Please discuss how the upcoming 2021 IRP will provide adequate planning and guidance on any future energy purchase agreements filed under section 71 of the UCA.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.16.1.

17.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: BC HYDRO ENERGY PROCUREMENT PROCESSES
***Clean Energy Act*, Section 2;**
Government of BC, CleanBC Report dated December 2018, p. 13[1]
BC Energy Objectives

The *Clean Energy Act* (CEA) includes the following BC energy objectives:

2(f): to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America; and

2(l): to foster the development of first nation and rural communities through the use and development of clean or renewable resources.

The CleanBC Report states on page 13 "We will work in collaboration with Indigenous peoples to seize new clean economy opportunities and help communities adapt to the impacts of climate change."

2.17.1 Under Section 71 of UCA, does BC Hydro consider the BC energy objectives most relevant to the review of the EPA's included in this Application to be 2(f) and 2(l)? If not, please explain which energy objectives are the most relevant.

RESPONSE:

As noted in Part 7 of BC Hydro's Application with respect to these EPAs, the EPAs support the following British Columbia Energy Objectives prescribed in the *Clean Energy Act*:

- **Objective 2(a) – to achieve electricity self-sufficiency;**
- **Objective 2(c) – to generate at least 93 per cent of the electricity in B.C. from clean or renewable resources;**
- **Objective 2(d) – to use and foster the development in B.C. of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;**

[1] Clean Energy BC Report (December 2018)
https://cleanbc.gov.bc.ca/app/uploads/sites/436/2018/12/CleanBC_Full_Report.pdf

- **Objective 2(f) – to ensure BC Hydro's rates remain among the most competitive of rates charged by public utilities in North America;**
- **Objective 2(k) – to encourage economic development and creation and retention of jobs;**
- **Objective 2(l) – to foster the development of First Nation and rural communities through the use and development of clean and renewable resources; and**
- **Objective 2(m) – to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia**

Neither the *Utilities Commission Act* nor the *Clean Energy Act* requires BC Hydro or the BCUC to prioritize, or provide different weight to, any particular energy objective.

17.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: BC HYDRO ENERGY PROCUREMENT PROCESSES
***Clean Energy Act*, Section 2;**
Government of BC, CleanBC Report dated December 2018, p. 13[1]
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2(f): to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America; and

2(l): to foster the development of first nation and rural communities through the use and development of clean or renewable resources.

The CleanBC Report states on page 13 "We will work in collaboration with Indigenous peoples to seize new clean economy opportunities and help communities adapt to the impacts of climate change."

2.17.2 Has BC Hydro undertaken analysis to identify *new* clean energy opportunities in Indigenous communities (as opposed to renewals of existing projects)? Please explain and comment on whether there is a risk that the EPA renewals included in this Application could reduce the opportunities for new clean energy projects in Indigenous communities.

RESPONSE:

For the integrated system, no specific program has been adopted by BC Hydro to identify new clean energy opportunities in Indigenous communities.

However, BC Hydro is developing a more comprehensive approach to cost-effectively reduce the amount of diesel used for electricity generation in Non-Integrated Areas, in support of Indigenous and community interests and needs, greenhouse gas reduction efforts, and the objectives in the Government of B.C.'s CleanBC plan. As part of these efforts, BC Hydro is engaging with Indigenous and non-Indigenous communities about their interests and needs, examining efforts in other jurisdictions, and reviewing technically and commercially feasible options, including renewable energy projects, while also

[1] Clean Energy BC Report (December 2018)
https://cleanbc.gov.bc.ca/app/uploads/sites/436/2018/12/CleanBC_Full_Report.pdf

ensuring that BC Hydro manages costs and risks to ratepayers. Given the EPA renewals included in this Application are all on the integrated system, there is no impact of renewal on opportunities for new clean energy project in the Non-Integrated Area.

BC Hydro notes that there are currently seven proposed projects with First Nations involvement that are included within our IPP and Long Term Purchase Volumes for the Integrated System (as provided in BC Hydro's F20-F21 RRA). The acceptance of the three EPAs that are the subject of this application does not impact those seven proposed First Nations projects.

18.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: Energy Procurement processes
Exhibit B-1, covering letter, p.1; Exhibit B-5, BCUC IR 10.2, 11.2.2.1, 21.2 and 42.1.1;
BC Hydro 2013 IRP, Chapter 9; Exhibit B-7, CEC IR 4.3; British Columbia Utilities Commission Inquiry Respecting Site C Final Report (Site C Inquiry Report), pp. 95, 157; BCUC Letter L-8-18 dated April 26, 2018; Merrimack Report, p. 47; SOP: Report on the SOP 2-Year Review (SOP 2-Year Review), 2011, p. 9[1]
Link to the IRP/timely update of key input data

BC Hydro discusses its EPA renewal approach in response to BCUC IR 42.1.1 and states that its approach to EPA renewals has been informed by Recommended Action 4 from the 2013 IRP (optimize the portfolio according to the key principle of reducing near-term costs while maintaining cost-effective options for long-term need).

BC Hydro states in response to CEC IR 4.3 that the Fall 2017 ABB forecast was published in January 2018 and reviewed by BC Hydro in early 2018. This Application was filed on May 31, 2018. BC Hydro states in BCUC IR 8.4 that the long run marginal cost (LRMC) used in the Application were estimated in 2015 and are now considered out of date.

BC Hydro states in response to BCUC IR 21.2 that the Delivery Price Adjustment Table used in this Application is the same as the table used in the 2013 IRP. The BC Hydro SOP 2011 2-Year review includes a Time of Delivery Table on page 9 based on the Clean Power Call. BC Hydro states in response to BCUC IR 10.2 that it has not updated the long-term forecast to address the issues raised in the Site C Inquiry Report. However, BC Hydro adjusted its May 2016 load forecast and provides additional detailed information on: (1) new and updated information to the LRB; (2) the first year of deficit in the updated LRB; and (3) updated LRBs response to BCUC IR 1.11.2.2.1.

The Site C Inquiry report found that "…BC Hydro's proposed Mid C forecast should not be relied upon" and BC Hydro used "…out of date cost estimates for wind and solar, and does not anticipate any future decline in prices."

By Letter L-8-18 dated April 26, 2018, the BCUC accepted FortisBC Inc.'s 2018/2019 Annual Electric Contracting Plan. The Merrimack Report recommends on page 47 that the IRP should be updated as frequently as necessary to prevent over or under supply.

[1] Appendix D to BC Hydro's 2012 Application to Amend Net Metering Service RS 1289.

2.18.1 Please explain whether it is possible to project IPP needs in the absence of an updated IRP.

RESPONSE:

Confirmed, BC Hydro believes it is possible to project the need for energy and capacity contributions from IPPs in the absence of an updated IRP through the use of updated LRBs. The latest IRP continues to provide a basis for the planned resources impacting the LRB.

18.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: Energy Procurement processes
Exhibit B-1, covering letter, p.1; Exhibit B-5, BCUC IR 10.2, 11.2.2.1, 21.2 and 42.1.1;
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BC Hydro states in response to BCUC IR 21.2 that the Delivery Price Adjustment Table used in this Application is the same as the table used in the 2013 IRP. The BC Hydro SOP 2011 2-Year review includes a Time of Delivery Table on page 9 based on the Clean Power Call. BC Hydro states in response to BCUC IR 10.2 that it has not updated the long-term forecast to address the issues raised in the Site C Inquiry Report. However, BC Hydro adjusted its May 2016 load forecast and provides additional detailed information on: (1) new and updated information to the LRB; (2) the first year of deficit in the updated LRB; and (3) updated LRBs response to BCUC IR 1.11.2.2.1.

The Site C Inquiry report found that "…BC Hydro's proposed Mid C forecast should not be relied upon" and BC Hydro used "…out of date cost estimates for wind and solar, and does not anticipate any future decline in prices."

By Letter L-8-18 dated April 26, 2018, the BCUC accepted FortisBC Inc.'s 2018/2019 Annual Electric Contracting Plan. The Merrimack Report recommends on page 47 that the IRP should be updated as frequently as necessary to prevent over or under supply.

[1] Appendix D to BC Hydro's 2012 Application to Amend Net Metering Service RS 1289.

2.18.2 Please explain whether there could be regulatory efficiency from BC Hydro filing an Annual Electric Contracting Plan, which could include an update of key IRP inputs as they relate to energy procurement (such as load resource balance, Mid-C price estimates, avoided cost of new energy estimates such as wind, etc.), as a way of ensuring data is as up to date as possible between IRP filings? Please explain, including the information BC Hydro considers would be useful to include.

RESPONSE:

BC Hydro believes that filing a document similar to the FortisBC Annual Electric Contracting Plan (AECP) will add to the regulatory burden. In BC Hydro's view this will not create additional regulatory efficiencies because BC Hydro is expected to file updated information with each application. BC Hydro already endeavors to use the most appropriate data and planning assumptions available in making decisions and in preparing regulatory applications related to energy procurement. BC Hydro notes that the government has enacted legislation to provide the BCUC with the power to review and approve BC Hydro's next IRP. BC Hydro expects that the frequency of future IRPs and related information submissions would be addressed in that context.

18.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: Energy Procurement processes
Exhibit B-1, covering letter, p.1; Exhibit B-5, BCUC IR 10.2, 11.2.2.1, 21.2 and 42.1.1;
BC Hydro 2013 IRP, Chapter 9; Exhibit B-7, CEC IR 4.3; British Columbia Utilities Commission Inquiry Respecting Site C Final Report (Site C Inquiry Report), pp. 95, 157; BCUC Letter L-8-18 dated April 26, 2018; Merrimack Report, p. 47; SOP: Report on the SOP 2-Year Review (SOP 2-Year Review), 2011, p. 9[1]
Link to the IRP/timely update of key input data

BC Hydro discusses its EPA renewal approach in response to BCUC IR 42.1.1 and states that its approach to EPA renewals has been informed by Recommended Action 4 from the 2013 IRP (optimize the portfolio according to the key principle of reducing near-term costs while maintaining cost-effective options for long-term need).

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[1] Appendix D to BC Hydro's 2012 Application to Amend Net Metering Service RS 1289.

2.18.3 Please list in table form each of the issues/factors identified in the pages 78 to 82 of the BCUC Site C Inquiry, and note whether any of these items were addressed in the adjustments made to the May 2016 forecast (and if so, to what extent).

RESPONSE:

The following table summarizes the extent to which the referenced issues/factors are addressed as part of the adjustments made to the May 2016 Load Forecast. The table also provides commentary on the extent to which the referenced issues/factors are reflected in BC Hydro's October 2018 six-year load forecast as filed in BC Hydro's F20-F21 RRA proceeding.

A 20-year load forecast will be filed in the F20-F21 RRA proceeding once it is available.

Issues/Factors	Addressed in the Adjustments made to the May 2016 Load Forecast
Recent developments in the industrial sectors	**Yes. The LNG forecast methodology was revised to be consistent with the probabilistic approach used to forecast all large industrial customers as per the October 2018 Load Forecast.**
Accuracy of historical load forecasts	**No. Improvements to the large industrial sector and other sectors were included in the October 2018 Load Forecast. These improvements are anticipated to enhance the accuracy of the forecast.** **BC Hydro develops a low, mid and high forecast. Figure 1 in BC Hydro's response to BCUC IR 1.11.2.2.1 shows that the mid October 2018 Load Forecast falls within the May 2016 Load Forecast uncertainty bands.**

Issues/Factors	Addressed in the Adjustments made to the May 2016 Load Forecast
GDP and other forecast drivers	**No. BC Hydro respectfully disagrees with the Site C Inquiry panel findings that the differences in GDP and disposable income economic forecasts produced by two equally reputable economic forecast organizations (Robert Fairholm Economic Consultant which informed the May 2016 Load Forecast and the Conference Board of Canada Provincial Forecast as contained in the Site C Inquiry) would have a material impact on the May 2016 Load Forecast.** **The October 2018 Load Forecast incorporates an updated GDP forecast from the Provincial Government (September 2018) and updated other economic drivers from the Conference Board of Canada (June 2018).** **In BC Hydro's load forecast, the total provincial GDP is a direct driver for only a portion of one subsector (Light Industrial), which makes up about 5 per cent of BC Hydro's total firm sales.**
Price elasticity	**Yes. The price elasticity factor was modified from -0.05 to -0.1.** **The modified elasticity factor of -0.1 was used to develop the October 2018 Load Forecast. BC Hydro reviewed its elasticity assumption in response to concerns raised in the Site C Inquiry and recommendations included in the fiscal 2018 internal audit of the load forecast.**
Future rate increases	**No. The electricity rate increase projection reflected in the adjusted May 2016 Load Forecast is based on BC Hydro's 2013 10-year rates plan and a nominal 2 per cent increase per annum for the years beyond the 10-year rates plan.**
Potential disrupting trends	**No. The adjusted mid May 2016 Load Forecast does not reflect the 2018 CleanBC plan which includes electrification initiatives such as the zero emission targets for vehicle sales.** **BC Hydro's high and low uncertainty bands include the impacts of potential disrupting trends to drivers of the mid forecast as such as economic growth.**
Flattening electricity demand	**No. The adjusted mid May 2016 Load Forecast does not address changes in electricity demand as fiscal 2015 is the last year of sales data used to calibrate the May 2016 Forecast.** **While BC Hydro acknowledges that the October 2018 Load Forecast shows growth rates that are lower than previously forecast, they are not flat. The October 2018 forecast of growth in total domestic sales from fiscal 2018 to fiscal 2023 is 0.5 per cent.**

19.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: BC Hydro Energy Procurement Processes
Exhibit B-7, CEC IR 3.2; Exhibit B-5, BCUC IR 42.1.1, BCUC IR 42.5;
Merrimack Report, pp. 5, 47; BC Hydro Overview of BC Hydro's Energy Procurement Practices (Energy Procurement Practices Overview) dated November 2013, p. 2[1]
Energy Procurement Principles

BC Hydro states in response to Commercial Energy Consumers Association of British Columbia (CEC) IR 3.2 that it "… has not developed a process to identify the lowest cost contracts within the EPA renewal portfolio prior to entering into negotiations with specific IPP projects." BC Hydro further states in response to BCUC IR 42.1.1 that the total cost forecast from the 10-Year-Rates Plan has been used to provide a financial framework and budget within which to manage the costs for all EPA renewals.

BC Hydro states in response to BCUC IR 42.5 that it does not anticipate that an analysis of energy procurement processes will be carried out in preparation for the next IRP.

The Merrimack Report recommends on page 5 that BC Hydro develop standards for evaluating and negotiating bilateral contracts and make the standards transparent to stakeholders. On page 47 the report recommends that BC Hydro develop project viability criteria and transparent weightings for price and non-price factors to evaluate bids and select procurements.

BC Hydro describes its energy procurement principles in its Energy Procurement Practices Overview dated November 2013 and includes on page 2 the following principles:

- Cost-effectiveness – enter into contracts with proponents which provide cost-effective electricity that benefits BC Hydro's ratepayers, and
- Transparency – provide clear information on procurement requirements including eligibility, fees, evaluation criteria and selection of projects.

2.19.1 Please explain how BC Hydro has met its cost-effectiveness and transparency principles in this Application.

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[1] BC Hydro, Overview of BC Hydro's Energy Procurement Practices (November 2018) https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/energy-procurement-practices.pdf

RESPONSE:

For the EPAs that are the subject of this Application, BC Hydro's approach to the bilateral negotiations was consistent with the energy procurement practices for Bilateral Negotiations as set out in section C of the *Overview of BC Hydro's Energy Procurement Practices* (November 2013).

Prior to commencement of negotiations with each of the IPPs, BC Hydro provided to each of the IPPs an "IPP Information Package". This package, which is generally the same for each IPP that enters into bilateral negotiations with BC Hydro, outlines and includes: the requirement for a non-disclosure agreement, First Nations consultation matters, interconnection information, metering and permitting requirements, what is required from the IPP for BC Hydro to conduct a cost of service analysis, electric service requirements, and regulatory matters. The purpose of this information package has been to provide transparency to each of the IPPs on how we wished to proceed with each of the bilateral negotiations.

A sample of an IPP Information Package is attached for reference. Within the IPP Information Package and throughout its discussions with the IPPs, BC Hydro noted that, as described in the 2013 IRP (section 4.2.5.1), the EPA renewal negotiations would consider the Cost of Service of the Seller's Plant, among other factors such as the IPP's opportunity cost and BC Hydro's opportunity cost.

With respect to cost-effectiveness, the Application and the responses to these IR responses speak to the cost-effectiveness of each of the EPAs. These EPAs, and the preceding run-of-river EPAs submitted to the BCUC during the past several years, have been filed with the BCUC under section 71 of the *Utilities Commission Act*. It is BC Hydro's view that through the section 71 filing process, the cost effectiveness of an EPA is reviewed and tested and transparency is provided to the BCUC and potentially other interested parties.

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EPA Renewal Process
IPP Information Package

This document outlines some of the key steps and information requirements associated with negotiating an EPA renewal with BC Hydro. It is intended to provide a general overview of the process and is not exhaustive.

This document is provided solely for the purpose of advancing our confidential and without prejudice discussions regarding the potential renewal of an EPA. It is not an offer and does not create any legally binding obligations, rights, or liabilities. No agreement will exist between the parties regarding these matters until a settlement has been reached and both parties have signed and delivered final agreements reflecting or resulting from the discussions. Any costs incurred by the Independent Power Producer (IPP) during the negotiation of an EPA renewal are the responsibility of the IPP.

Please direct any questions regarding the EPA renewal process to:

1. Non-Disclosure Agreement

- Prior to starting negotiations for an EPA renewal, a Confidentiality and Non-Disclosure Agreement will need to be executed between BC Hydro and the IPP / Seller. This agreement is intended to protect the confidential information of both parties. A draft of the agreement will be provided for review prior to the next meeting with BC Hydro.

2. First Nations

- First Nations whose consultative boundary includes the Seller's Plant may be informed of BC Hydro's intention to seek renewal of the EPA, either by letter or through the engagement process BC Hydro has already established with the First Nation.

- The IPP is requested to prepare responses to the questions listed in Schedule A in order for BC Hydro to assess First Nations consultation requirements.

- The IPP is responsible for carrying out any required consultation with First Nations. Prior to the renewal of an EPA, BC Hydro will assess the adequacy of the IPP's consultation. The form of any information required in relation to the IPP's consultation will follow, as required.

- BC Hydro may inform affected First Nations of the outcome of its assessment prior to the renewal of an EPA.
- Any questions regarding First Nations matters can be directed to:

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3. Interconnections

- Under the existing agreements with BC Hydro, the interconnection requirements for the Seller's Plant formed part of the EPA. In the time since these agreements were signed, electrical utilities have matured in their understanding of interconnections and their impacts on power systems and BC Hydro's interconnection requirements have been updated for improved system reliability, stability, and safety. As a result, prior to the renewal of any EPAs:
  - i) the existing Seller's Plant will need to be assessed to confirm installed equipment and determine compliance with current standards;
  - ii) any gaps in compliance will be reviewed and the upgrades necessary to address any material gaps will be identified;
  - iii) these upgrades will need to be implemented by BC Hydro and / or the IPP, as applicable; and
  - iv) an Interconnection Agreement will need to be executed.

- The specific steps associated with the interconnection review process are outlined in Schedule B. Due to the potential time requirements for the review and the implementation of any necessary upgrades, it is recommended that BC Hydro Interconnections be contacted as soon as possible to initiate the process:

  - For distribution-connected projects: Distribution.Generators@bchydro.com
  - For transmission-connected projects: Transmission.Generators@bchydro.com

4. Permits

- The IPP is requested to summarize the following in table format (see Schedule C for template):

  - Permits required for continued operation of the Seller's Plant over expected renewal term.
  - Permit issuing agency and the renewal agency, if applicable.
  - Date of permit issuance and expiry.
  - If permit has expired, or is expected to expire during the renewal term, briefly outline expected renewal process (e.g. First Nations consultation, stakeholder consultation, etc.) and expected renewal date.

- Copies of all Material Permits required to operate the Seller's Plant during the EPA renewal term are to be submitted to BC Hydro for review.

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5. Cost of Service

- As described in the 2013 Integrated Resource Plan (section 4.2.5.1), the EPA renewal negotiations will consider the Cost of Service (COS) of the Seller's Plant, among other factors. In general, BC Hydro will be seeking to renew EPAs with those plants that have the lowest costs, greatest certainty of continued operation, and best system support characteristics.

- A template will be provided as a guide for providing the financial information required for the COS review. To initiate the data collection process, the following provides a general list of the information that will be requested (this list is not exhaustive):

    - A summary of the actual costs incurred by the IPP directly in relation to the operation of the Seller's Plant during the most recent 5 full years.
    - A corresponding monthly summary of the actual total energy deliveries to the Point of Interconnection (net of internal losses), further separated into energy sales to BC Hydro and energy sales to others, if applicable.
    - Corporate financial statements (balance sheet, income statement, and cash flow statement), prepared by a Certified Accountant, supporting the actual cost information provided (audited statements to be provided, if available).
    - A summary of the capital and operations and maintenance costs that the IPP reasonably expects to incur, directly related to the Seller's Plant, during the renewal term (at a minimum provide a 20 year projection and at a maximum 40 years). Projected expenditures are to be validated by an independent Professional Engineer and supported by engineering studies, as applicable.
    - A condition assessment of the Seller's Plant prepared by an independent Professional Engineer and a Long Term Operating Plan for the Seller's Plant, as per Schedule D.

- The information provided by the IPP will be subject to due diligence, which may include further independent verification. BC Hydro may request additional supporting information to substantiate the information provided.

6. Revenue Metering

- Under the existing EPA, BC Hydro installed and maintained the requisite revenue meters at its cost. BC Hydro's current practice related to revenue meters has since changed.

- BC Hydro will continue to be responsible for the installation, inspection, and maintenance of the revenue meters. However renewed EPAs will require revenue metering equipment to be leased from BC Hydro for a nominal monthly fee. The IPP will be requested to enter into a "Metering Equipment Lease" with BC Hydro in substantially the form attached as Schedule E prior to executing the EPA. (Note, any changes required to the existing revenue meters to meet current standards of practice will be identified as part of the interconnection review.)

- Under a renewed EPA, the IPP will be responsible for preparing and submitting invoices to BC Hydro for any energy sales. For invoice preparation purposes, BC Hydro will provide the IPP with internet access to revenue meter data at a nominal monthly fee – a flat meter reading service fee and an internet access fee based on the capacity of the Seller's Plant. An "Agreement for Internet Access to

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the Customer's Revenue Metering Data" must be signed prior to executing the EPA. See Schedule F for the form of agreement.

7. Electric Service Agreement

- If the IPP requires black-start capability or station service from BC Hydro in the event of a plant outage, an "Electric Service Agreement" (ESA) for service under the Electric Tariff Rate Schedule 1853 will need to be signed prior to executing the EPA. If there is an existing ESA for the Seller's Plant, it may need to be amended or replaced to be consistent with current standards. See Schedule G for a sample form of the ESA.

8. Regulatory

- It is anticipated that any renewed EPAs will need to be filed with the British Columbia Utilities Commission (BCUC) for acceptance under section 71 of the Utilities Commission Act.

- Based on past experience, BC Hydro has allowed 180 days following the execution of a new EPA for the regulatory filing and acceptance process. BC Hydro will prepare the filing with assistance from the IPP.

- The IPP is responsible for obtaining independent advice concerning any regulatory requirements.

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Schedule A
First Nations – Assessment of Consultation Requirements

In contemplating whether to enter into a new EPA or to renew an existing EPA, BC Hydro reviews information provided by IPPs to assess the potential incremental impact on asserted Aboriginal rights and title or treaty rights. The information requested below will assist BC Hydro in preparing its assessment. BC Hydro may request additional information or clarification of the information provided.

1. Please provide the location of the generating facility in latitude and longitude, and in distance (kilometres) and direction from the Point of Interconnection.

2. Please provide the length of the transmission line and the voltage of the line.

3. Please indicate whether the project is on Crown land or private fee simple land.

4. Please provide copies of all permits required for the original construction and operation of project.

5. Do you anticipate any changes to the physical footprint of the facility in order to provide power under the EPA?

6. Have there been any consultations with First Nations since the construction of the facility? If so, please provide details.

7. a) Will there be changes in the energy output of the facility as a result of the EPA renewal or a new EPA?

   b) In addition, for biomass or gas-fired facilities: will there be a change to the fuel source as a result of the EPA renewal or a new EPA?

8. Will there be changes to the operations of the facility as a result of the renewal of the EPA?

9. If the answer to Questions 3, 5, 7 or 8 is yes, will new Crown permits or amendments to existing Crown permits be required?

10. Have any environmental studies of the project been done since the EPA was signed? If so, please provide those studies. If not, please explain why not.

11. Are there any environmental impacts that resulted from the original construction that have the potential to worsen with the continued operation of the facility?

12. Would the facility be decommissioned or decommissioned earlier if the EPA were not renewed?

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Schedule B
Interconnection Review Process

Requirement	Distribution-Connected Generators	Transmission-Connected Generators	Comments
i) Confirm installed equipment and assess compliance with current standards.			
Maintenance Testing Reports	x (DIR)	x (TIR)	Under the current Distribution / Transmission Interconnection Requirements (DIR/TIR) and most operating orders, generators are required to prepare, and if requested submit, maintenance testing reports every 2 years.
WECC Model Validation Test Report	x	x	WECC requirement for all projects with a single generator >10MVA or aggregate generation >20MVA.
Plant Record Generator Interconnection Data Form (GIDF)	x	x	Required for all projects to confirm existing plant equipment.
Plant Assessment (Gap Analysis)	x (against DIR)	x (against TIR)	IPP to engage a Professional Engineer to assess plant against DIR or TIR and identify any gaps. Assessment to include current revenue metering standards (Requirements for Complex Revenue Metering).
Interconnection Review	x ($*k deposit; final fee based on actual cost)	x ($*k deposit; final fee based on actual cost)	At least 1 month should be budgeted for BCH's review of the above information (turnaround times are dependent on available resources and any information gaps).
ii) Review compliance gaps and identify necessary upgrades for any material gaps. (if there are no compliance gaps, proceed to iii)			
System Impact Study Application & Agreement	TBD (deposit on a case-by-case basis)	TBD (deposit on a case-by-case basis)	If any material gaps are identified, the IPP will be requested to submit a System Impact Study (SIS) application. Prior to initiating a study, a study agreement and study deposit will be required.
System Impact Study	TBD (final fee based on actual costs)	TBD (final fee based on actual costs)	BCH's study will determine the scope and high level cost estimate of the network upgrades required on BCH's side of the POI and the equipment requirements on the IPP's side of the POI. Approx. 3 months should be budgeted for this study.
Facilities Study	TBD (deposit TBD; final fee based on actual costs)	TBD (deposit TBD; final fee based on actual costs)	If material gaps are identified which require network upgrades on BCH's side of the POI, a Facilities Study will be carried out to provide a detailed scope and cost estimate for the upgrades. Approx. 3-5 months should be budgeted for this study.
iii) Execute Interconnection Agreement.			
Interconnection Agreement	x (DGIA)	x (SGIA)	The Interconnection Agreement will contain the specific Project Interconnection Requirements (PIR), including the existing interconnection equipment and additional equipment requirements on the IPP's side of the POI. In general IPPs will have 1 yr to complete these upgrades, unless there are critical reliability, stability, or safety concerns.

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Schedule C
Permit Requirements

Permit	Issuing Agency / Renewal Agency	Issuance Date	Expiry Date	Expected Renewal Process (if applicable) (key steps only)	Expected Renewal Date

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Schedule D
Long Term Operating Plan

Sample Items for Long-Term Operating Plans (Hydro Projects)

1. PROJECT LAYOUT AND COMPONENTS
2. LOCATION AND ACCESS
3. STAFFING REQUIREMENTS
4. CONTACT INFORMATION OF KEY PERSONNEL
    a. For Daily Operational Matters
    b. For Outage Scheduling
    c. For Contractual Matters
5. WATER LICENSE REQUIREMENTS
    a. Instream Flow Release
    b. Ramping Rates and Limits
6. HYDROLOGY
    a. Watershed Characteristics and Seasonal Patterns
    b. Annual Inflow Profile
7. GENERATION
    a. Generation Characteristics and Operating Strategy
    b. Unit/Plant Maximum Continuous Rating and Operating Range
    c. Start/Stop Ramp Rates
    d. Monthly Energy Profile at the Powerhouse and Point of Interconnection
    e. Storage and Load Shaping Capability
    f. Remote Control Capability by Operators
    g. Gross Head
    h. Headpond Flushing Requirements
    i. Station Service or Parasitic Loads
8. TRANSMISSION
    a. Point of Interconnection Location
    b. Revenue Meter Location
    c. Transmission Loss between Powerhouse and POI
9. OUTAGE REQUIREMENTS
    a. Maintenance Strategy
    b. Typical Unit and Plant Outage Requirements and Generation Impacts
    c. Target Monthly Availability
    d. Long Term Outage Schedule
10. PROJECT DRAWINGS AND PHOTOS
    a. Location Map
    b. Project Layout
    c. Intake General Arrangement Plan
    d. Powerhouse General Arrangement Plan
    e. Single Line Diagram
    f. Photos of Major Project Components
    g. Site Photos

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Schedule E
Metering Equipment Lease

METERING EQUIPMENT LEASE [v. 06/14]
(FOR INDEPENDENT POWER PRODUCERS)

THIS AGREEMENT ("Lease") is made the _____ day of _____.

BETWEEN:

[Legal Name]

having an office at

[Address]

("Power Generator")

AND:

British Columbia Hydro and Power Authority,
a Crown Corporation with a Corporate Office address at 333 Dunsmuir St – 17th Floor, Vancouver, B.C. V6B5R3

("B.C. Hydro")

WHEREAS:

(A) The Power Generator desires to install metering equipment to record deliveries of electricity to B.C. Hydro's system pursuant to an Electricity Purchase Agreement between the Power Generator and B.C. Hydro or pursuant to an Enabling Agreement between the Power Generator and Powerex Corp., a wholly owned subsidiary of BC Hydro, or pursuant to both; and

(B) B.C. Hydro has agreed to lease metering equipment to the Power Generator under the terms and conditions of this lease agreement.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the mutual promises and covenants made herein, the parties agree as follows:

ARTICLE 1
DEFINITIONS

1.1 In this Lease, the following words shall have the following meanings:

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1.1.1 "Power Generator's Plant" means the power generation plant and facilities of Power Generator as described in Schedule "A".

1.1.2 "Metering Equipment" means the electric revenue meter, modem, and ancillary equipment (if any) described in Schedule "A".

1.1.3 "Term" means the term of the lease of the Metering Equipment as described in section 5.1.

ARTICLE 2
B.C. HYDRO'S OBLIGATIONS

2.1 B.C. Hydro shall lease to the Power Generator the Metering Equipment described in Schedule "A" attached to and forming part of this Lease.

2.2 B.C. Hydro shall install, inspect and maintain the Metering Equipment during the Term of the Lease, and shall remove the Metering Equipment upon expiry or earlier termination of the Term.

2.4 The Metering Equipment is, and shall always remain, the sole property of B.C. Hydro.

2.5 The meter(s) forming part of the Metering Equipment shall, upon installation, comply with the requirements of the Government of Canada, Measurement Canada Branch, the ***Electricity and Gas Inspection Act*** and other legislation having jurisdiction with respect to the operation and maintenance of the meter(s). B.C. Hydro shall periodically inspect the meter(s) to ensure that its/their operation continues to meet these requirements.

2.6 B.C. Hydro shall not be liable for any damages or losses, howsoever caused, including, but not limited to:

(a) the Metering Equipment or any defect therein; and

(b) the provision of the services contemplated by this Agreement.

ARTICLE 3
POWER GENERATOR'S OBLIGATIONS

3.1 The Power Generator agrees that it will, on or before the date scheduled for installation of the Metering Equipment by B.C. Hydro, complete the installation of all facilities, equipment and connections ("Facilities") necessary for the installation of the Metering Equipment in accordance with the responsibilities assigned to the Power Generator as set forth in Section 10 of B.C. Hydro's "Requirements for Complex Revenue Metering – March 2014". The Facilities will be installed in accordance with all applicable laws and regulations, and B.C. Hydro requirements.

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3.2 The Power Generator shall:

(a) during normal business hours, allow B.C. Hydro to verify, inspect and maintain the Metering Equipment;

(b) provide and maintain clear access to the Metering Equipment in order that routine inspection and maintenance can be performed;

(c) not do, nor allow to be done in the Power Generator's Plant, anything which may endanger or adversely affect the operation of the Metering Equipment without first notifying B.C. Hydro's Metering Department and receiving its written permission to continue;

(d) conduct semi-annual inspections of the exterior condition of the Metering Equipment and report immediately to B.C. Hydro any observable damage to, or malfunction of, the Metering Equipment or any meter seals: and

(e) permit BC Hydro unrestricted access to the Power Generator's Plant at the expiry or earlier termination of the Lease for the purpose of removing the Metering Equipment.

3.3 The Metering Equipment will remain in the care and custody of the Power Generator during the Term and until B.C. Hydro has removed or taken delivery of the Metering Equipment upon the expiry or earlier termination of the Term. The Power Generator shall be responsible for any loss or damage occurring to the Metering Equipment while the same is in the care and custody of the Power Generator, ordinary wear and tear only excepted.

ARTICLE 4
LEASE FEE

4.1 The Power Generator shall pay to BC Hydro an annual lease fee as set out in Schedule "A", and adjusted from time to time pursuant to section 4.2, ("Lease Fee") which shall be payable in advance of each year during the Term of the Lease or as set forth in Schedule "A" attached to and forming part of this Agreement.

4.2 The Lease Fee shall be subject to review and adjustment by B.C. Hydro at five year intervals during the Term of the Lease, subject to review and adjustment by B.C. Hydro at the end of the Term of the Lease, and subject always to all of the provisions of this Lease.

ARTICLE 5
TERM & TERMINATION

5.1 The Term shall commence as of the installation date of the Metering Equipment at the Power Generator's Plant and shall remain in effect for the period of years specified in Schedule "A".

5.2 This Lease may be terminated by either party by giving the other party thirty (30) days written notice of its intention to terminate and upon the thirty-first (31st) day, the Lease is so terminated.

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5.3 In the event the Power Generator terminates this Lease prior to the end of the Term pursuant to section 5.2, B.C. Hydro reserves the right to charge and on being invoiced the Power Generator shall pay to B.C. Hydro on a lump sum basis, the lesser of the amount of the Leasing Fee for the remainder of the Term or a period of five years. In addition he Power Generator shall pay B.C. Hydro for any loss of or damage to the Metering Equipment (except for ordinary wear and tear).

5.4 The Power Generator acknowledges and agrees that if at any time it fails to comply with any provision of this Lease, B.C. Hydro may, at its option, without notice, immediately terminate this Lease and disconnect and remove the Metering Equipment from the Power Generator's Plant. In that event, BC Hydro may also charge and the Power Generator shall pay the costs in the same manner as set forth in section 5.3.

IN WITNESS WHEREOF the Parties have executed this Lease as of the date first written on page one.

[Legal Name]	**B.C. Hydro**
Per: _____ (authorized signatory)	Per: _____ (authorized signatory)
Name: _____	Name: _____

BC hydro
FOR GENERATIONS

SAMPLE DOCUMENT

METERING EQUIPMENT LEASE [v. 09/14]

Schedule "A"

Metering Equipment:

A Schlumberger/Itron Quantum **Q1000** [TBC], or equivalent electricity revenue class meter, including a modem, telecom interface and ancillary equipment, and capable of recording 30 minute load profile interval data; and being read remotely using means of telecom approved by BC Hydro.

Power Generator's Location

The Power Generator location is:

Station Code: [*]

Plant Address:

[Number street/road/etc.
City/Town
Postal Code
(Geo-Coordinates, if available)]

Location of the Leased Equipment (Point-of-Metering): [*]

Rental Fee

[$*] per month.

Meter Lease Period
[* years commencing Month, Day, Year]

BC hydro
FOR GENERATIONS

SAMPLE DOCUMENT

Schedule F
Agreement for Internet Access to Customer's Revenue Metering Data

AGREEMENT FOR INTERNET ACCESS TO CUSTOMER'S REVENUE METERING DATA

Customer: **Date**:

BC Hydro agrees to give Customer Internet access to Customer's revenue metering data subject to the terms and conditions below:

1. **Customer Access**. Customer's employees authorized to access Customer's accounts, and the accounts which each employee is authorized to access, are shown in the table below:

Name	E-Mail	Phone	BC Hydro Acct No

Customer will notify BC Hydro of any changes in employees authorized to access Customer's revenue metering data.

2. **Billing Data Governs**. In the event any discrepancies appear between metering data accessed by Customer via the Internet and data shown in BC Hydro's monthly billings, the data in the monthly billings will govern.

3. **Monthly Fee**. Customer agrees to pay a graduated fee of:
   - $50/month for less than or equal to 10 MW,
   - $100/month for greater than 10 MW and less than or equal to 30 MW,
   - $150/month for greater than 30 MW for this service. The fee, plus any GST and PST will be added to the Customer's monthly billing. BC Hydro reserves the right to change this fee with 2 months prior notice to the Customer.

4. **No Liability**. While BC Hydro uses reasonable measures to protect its computer systems and software from viruses and other contaminating or disrupting devices, BC Hydro cannot guarantee that Customer's computer systems and software will not be contaminated or damaged as a result of accessing revenue metering data via the Internet. BC Hydro assumes no responsibility or liability for any resulting contamination or damage. BC Hydro will further not have any liability for unauthorized access by Customer's employees or others to Customer's revenue metering data via the Internet or other electronic means.

5. **Termination of Service**. BC Hydro reserves the right to terminate this service at any time upon 30 days prior written notice to Customer.

Accepted and Agreed to by Customer:
Signature:_____
Name: _____
Title: _____

BC hydro
FOR GENERATIONS

SAMPLE DOCUMENT

Schedule G
Electric Service Agreement

[v. 06/15]

THIS ELECTRIC SERVICE AGREEMENT ("the Agreement"), made as of the___ th. day of_____ ,_____ for Service under Rate Schedule 1853

BETWEEN:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, having its head office at 333 Dunsmuir Street, Vancouver, British Columbia
("B.C. Hydro")

AND:

***Company Name*.** having an office at _____*Address*
("the Customer")

WITNESSES THAT the Customer and B.C. Hydro agree as follows:

1. In this Agreement, "Customer's Premises" means the premises located at____*description of location*

2. The supply of electricity shall be three phase alternating current, at a frequency of 60Hz +/- 0.1Hz delivered at a nominal potential of_____ +/- 10% volts at the Point of Delivery subject to normal variations.

3. The electricity supplied and taken is subject to the terms and conditions of the Electric Tariff of B.C. Hydro including the provisions of Rate Schedule 1853 or amendments thereto or replacements thereof as filed with and approved by the Utilities Commission. The Customer may inspect the aforesaid Electric Tariff during normal working hours at any general office of B.C. Hydro and such right to inspect is sufficient notice of the terms and conditions and rate schedules contained therein.

4. Customer confirms that it is an Independent Power Producer and that electricity taken under Rate Schedule 1853 will be used solely for maintenance and black-start requirements of its power production facility located at Customer's Premises described above, and further that electricity taken under this Rate Schedule shall not be used to displace electricity that would normally be generated by Customer.

5. This Agreement shall continue and remain in force for an initial term of one year from the date the service is first energized. It shall continue unless terminated by either party giving the other not less than six months' notice in writing, and it shall, upon expiration of the said notice period so terminate.

6. B.C. Hydro owns and is responsible for the maintenance of only the following electrical equipment installed or to be installed on the Customer's premises.

   (a) Meters for billing purposes.

BC hydro
FOR GENERATIONS

SAMPLE DOCUMENT

7. The Customer owns and is responsible for the maintenance of any other electrical equipment located on the Customer's premises.

8. The load shall not exceed ____ kV.A of maximum demand without prior written approval of B.C. Hydro.

IN WITNESS WHEREOF the duly authorized representative of each party has executed this Agreement.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Per:

Signature: _____

Name: _____

Position: _____

Per:

Signature: _____

Name: _____

Position: _____

19.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: BC Hydro Energy Procurement Processes
Exhibit B-7, CEC IR 3.2; Exhibit B-5, BCUC IR 42.1.1, BCUC IR 42.5;
Merrimack Report, pp. 5, 47; BC Hydro Overview of BC Hydro's Energy Procurement Practices (Energy Procurement Practices Overview) dated November 2013, p. 2[1]
Energy Procurement Principles

BC Hydro states in response to Commercial Energy Consumers Association of British Columbia (CEC) IR 3.2 that it "… has not developed a process to identify the lowest cost contracts within the EPA renewal portfolio prior to entering into negotiations with specific IPP projects." BC Hydro further states in response to BCUC IR 42.1.1 that the total cost forecast from the 10-Year-Rates Plan has been used to provide a financial framework and budget within which to manage the costs for all EPA renewals.

BC Hydro states in response to BCUC IR 42.5 that it does not anticipate that an analysis of energy procurement processes will be carried out in preparation for the next IRP.

The Merrimack Report recommends on page 5 that BC Hydro develop standards for evaluating and negotiating bilateral contracts and make the standards transparent to stakeholders. On page 47 the report recommends that BC Hydro develop project viability criteria and transparent weightings for price and non-price factors to evaluate bids and select procurements.

BC Hydro describes its energy procurement principles in its Energy Procurement Practices Overview dated November 2013 and includes on page 2 the following principles:

- Cost-effectiveness – enter into contracts with proponents which provide cost-effective electricity that benefits BC Hydro's ratepayers, and
- Transparency – provide clear information on procurement requirements including eligibility, fees, evaluation criteria and selection of projects.

2.19.2 Please explain how the total cost framework within the 10-Year Rates Plan provides a financial framework to manage the costs for EPA renewals.

---

[1] BC Hydro, Overview of BC Hydro's Energy Procurement Practices (November 2018) https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/energy-procurement-practices.pdf

RESPONSE:

Previously, the total cost forecast from the 10-Year Rates Plan had been used to provide a financial framework and budget within which to manage the costs for all EPA renewals (see section 1.3 of the Application). This financial framework is now no longer applicable.

The actions included in Phase 1 of the Government's Comprehensive Review, BC Hydro's cost forecast for EPAs as included in the F20-F21 RRA, and BC Hydro's interim use of market prices to value energy during both surplus and deficit are currently guiding BC Hydro's EPA renewal decisions.

19.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: BC Hydro Energy Procurement Processes
Exhibit B-7, CEC IR 3.2; Exhibit B-5, BCUC IR 42.1.1, BCUC IR 42.5;
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- Cost-effectiveness – enter into contracts with proponents which provide cost-effective electricity that benefits BC Hydro's ratepayers, and
- Transparency – provide clear information on procurement requirements including eligibility, fees, evaluation criteria and selection of projects.

2.19.3 Please provide the last internal audit report on BC Hydro's energy procurement practices. If one has not been undertaken in the last 5 years, please explain why.

---

[1] BC Hydro, Overview of BC Hydro's Energy Procurement Practices (November 2013) https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/energy-procurement-practices.pdf

RESPONSE:

The last internal audit of energy procurement practices for BC Hydro is attached. Although the attachment states that it contains confidential information, it is now a public document and was filed as a public document in the F04-F05 RRA.

In September 2010 an external review of energy procurement practices was commissioned by BC Hydro and conducted by Merrimack Energy Group Inc. BC Hydro notes that there have been several further external reviews of BC Hydro's energy procurement practices after the Merrimack Report.

In the last five years external reviews of BC Hydro's procurement practices have included:

- **The Government's Comprehensive Review of BC Hydro (Phase 1), which was completed in February 2019, included a review of BC Hydro's purchase of power from Independent Power Producers; and**
- **Section 71 application processes for the seven executed EPA renewals, through which the BCUC assessed the need and cost-effectiveness of the agreements.**

BC Hydro has not carried out an internal audit of energy procurement practices in the last five years due to the limited energy procurement activities that have been carried out, use of standardized contract terms, fixed prices in the case of the SOP, and the internal due diligence undertaken to support the decision to sign each of the contracts.

April 22, 2003

To:
G.L. Simpson
W.G. Joe
W.M. Peterson
B.K. Goehring
A.J. Boldt
J. Barker
M.C. Hemmingsen
B.M. Milne
A.T Morris
G.N. Sherlock
J.G. Rodford
B. Van Ruyven
B.G. Elton
L.I. Bell
Audit and Risk Management Committee

AU0315D

Audit Services

BC hydro

Internal Audit Report

Integrated IPP Contract Management

Prepared by:
A. Lagnado
B. De Leeuw (Consultant)
M. Tannenbaum
D.A. Snow

Executive Summary

Objective

- To ensure that power purchases from in-service Integrated Independent Power Producers comply with the established contract terms and that the contracts are being appropriately managed by BC Hydro management.

Key Findings

- Overall, the Independent Power Producers (IPPs) contracts are being effectively executed and managed in accordance with the respective agreement terms.
- The internal process for contract development has evolved due to the increased energy procurement from IPPs. The need for stronger controls has led to a more transparent and streamlined solicitation and bid evaluation process leading up to the signing of standard Electricity Purchase Agreements (EPA). Other process improvements include competitive and fixed pricing for firm and non firm energy.
- The current organizational structure responsible for the various IPP processes has evolved significantly since the fall of 2002. Dispersed roles and responsibilities have recently been restructured. However, at the time of the audit in November and December 2002, this structure was in flux, since then, roles and responsibilities have been restructured and re-clarified.
- Elements of the Interconnection Process (determining the technical and economic feasibility of the interconnection, securing the service agreement and implementing the interconnection) were reviewed and deemed to be mature and comprehensive.
- Other areas of review included the financial management of the IPP contracts, executed in the 1990's, and their technical performance. Although financial management and operations were found to be effective, certain contract oversight rights are not currently exercised.

Executive Summary

Recommendations and Management Action Plans

- Given continued changes in the organizational structure, ensure that governance, roles/responsibilities and accountability are re-clarified and communicated to staff.
  - *Management agrees. Roles and responsibilities of key players for the overall acquisition function will be defined and documented, and the governance structure for IPP projects will be documented and communicated to all staff by Q1 F2004.*
- Standardize contract elements to create uniformity between the various contracts, and improve contract documentation control.
  - *Management agrees. Uniformity of contract elements will be achieved by Management with the assistance of Legal by Q2 F2004.*
- Consider the need to exercise existing oversight rights in contracts.
  - *Management agrees. Existing oversight rights such as tracking the fulfillment of contract requirements, review of key contract information and retention of records for ongoing performance management will be exercised by Q3 F2004.*

Contents

1. Background

- BC Hydro's resource acquisition policy allows for the entry of private Independent Power Producers (IPPs) to assist in meeting the domestic electricity requirements as initially outlined in the 1992 Government policy and guidelines and most recently in the Provincial Government Energy Policy released in 2002.
- The process for seeking IPP contracts has changed substantially over the years as follows:

Prior to Fiscal 2000

- From 1988 - 1994, requests for proposals seeking innovative technologies, sustainable and environmentally attractive projects were issued resulting in a total of 21 operational IPPs. The mix comprised of 17 small hydro and 4 thermal which are fueled by gas or woodwaste.

Fiscal 2000 to Fiscal 2002

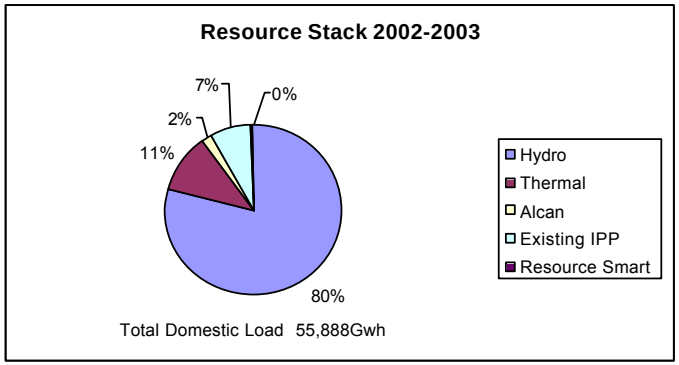
- The F2000 Integrated Electricity Plan update targeted 10 percent of future incremental load growth from "green" resources to support the Provincial Clean Energy Strategy.
- BC Hydro adopts a portfolio approach, starting with a green call in April 2000. This resulted in 23 "green" Electricity Purchase Agreements (EPA's) being signed.

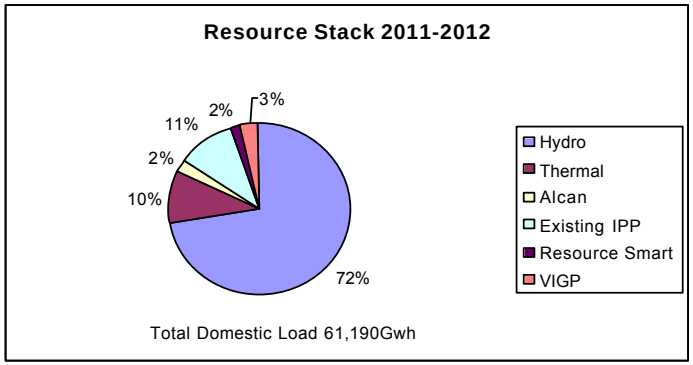
Fiscal 2003

- Projected purchases from existing IPP contracts are 3,690 GWh (excluding Alcan) at a cost of $248 M or an average price of $69 per MWh. The levelized price for these contracts over the contact life will be significantly lower.
- Board approves requests for proposals from Customer Based Generation and IPP green producers for a total of 1600 GWh/year.

1. Background

- IPP load is forecast to increase from approximately 4000 to 6500 GWh to meet domestic load growth over the next decade.





- The process to solicit, contract, build, connect and manage private sector generation to the BC Hydro integrated system is a complex multistage effort involving many groups. However, signing the contract and following the process still does not ensure that every contract will reach commercial operation.

KEY STAGES IN IPP LIFECYCLE

PROCESS

MANDATE	SOLICITATION AND COMMITMENT	CONSTRUCT AND INTERCONNECT	CONTRACT MGT.
• IDENTIFY LOAD GROWTH • FORECAST RESOURCES PLAN • RESOURCE ACQUISITION STRATEGY • BOARD APPROVAL & TARGETS	• REQUEST FOR QUALIFICATION • REQUIREMENTS AND CRITERIA • QUALIFICATION - SHORT LIST • CALL FOR TENDER & EVALUATION • ENERGY PURCHASE TERMS • COMMITMENT AND APPROVAL	• FINANCING, LICENSING, REGULATORY • CONSTRUCT AND PROJECT MGT. • INTERCONNECTION • TESTING AND COMMISSIONING • COMMERCIAL OPERATION	• OPERATIONS ASPECTS • SUPPLIER PERFORMANCE • BILLINGS, PAYMENTS& ADJUSTMENTS • CONTRACTUAL COMPLIANCE

2. Audit Objective and Scope

Objective

- To ensure that power purchases from in-service Integrated Independent Power Producers executed in the 1990's comply with the established contract terms and that the contracts are being appropriately managed by BC Hydro management.

Scope

- The audit, which was conducted in November and December 2002, included reviewing the key business risks, processes, procedures and controls which comprise, but are not restricted to, the following key components:
  - Governance and Structure
  - Contract Commitment Process
  - Construction and Interconnection Process
  - Contract Management Process
- Review of documentation and interviews with key personnel including; Green and Alternative Energy, Resource Management, Supply Investments, Corporate Finance, Generator Interconnections, Engineering Services, Revenue Metering, Transmission and Distribution LOBs.
- Focus on four in-service IPP's which were executed in the 1990's to review effective management, compliance with contract terms and the overall lifecycle process.
- Review of consent and fuel supply agreements were excluded from the scope as were Green and Customer Based Generation calls. However, a high level review of the process enhancements for Green and Customer Based Generation calls was conducted.

Audit Team

- The audit team was supplemented by a Professional Engineer with seasoned technical and contract management experience.

3a. Governance and Organizational Structure

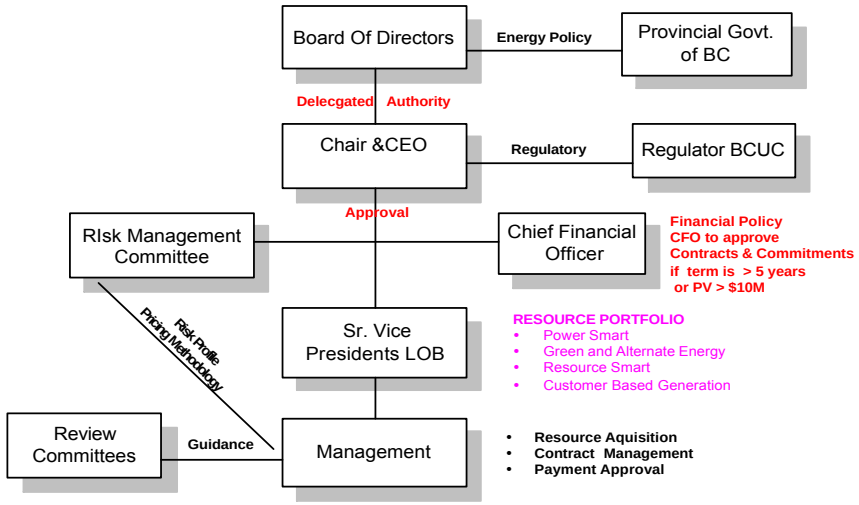
Mandate

- BC Hydro's resource acquisition policy allows for the entry of private Independent Power Producers (IPPs) to assist in meeting the domestic electricity requirements as per the Provincial Governments Energy Policies and BC Hydro's long term Integrated Electricity Plan.
- The Plan is for signed Electricity Purchase Agreements (EPAs) of approximately 800 GWh/year of Green energy for delivery by Fiscal 2004/2005 and another 1600 GWh/year of Green and Customer Based Generation acquisition by Fiscal 2006/2007.

Governance and Approval Authority

- The IPP contracts have a high profile due to the public awareness of the contracts and involvement in the process thus requiring a strong governance framework to ensure transparency and communication. The underlying Governance framework is as follows:

Governance and Implementation



3a. Governance and Organizational Structure

- In October 2001, the Board of Directors approved the terms for resource acquisition and delegated authority to the CEO to conclude and execute Electricity Purchase Agreements. While the final EPA's were signed by the CEO, the approval process did not adhere to the Financial Policy Framework in that formal commitment by the CFO was not clearly evidenced. Additionally, the process for referral, decision making and approval signoff was found to be informal and difficult to trace.
- In September and October 2002, Management introduced a number of changes to enhance the governance and accountability. This included revision and communication of the approval requirements in the Financial Policy, and enhanced requirements for review and documentation of contracts and commitments such as IPP's. Furthermore some of the key roles for energy acquisition were consolidated, and a committee established in August 2002 to review subsequent energy calls.
- Our interviews with management identified knowledge of the governance structure, roles, and approval routing was still not clear or well understood by staff and needed to be further articulated and communicated. As well, there is a need for clear delineation of roles, responsibilities and accountability which was still perceived as informal.
- There are many BC Hydro staff involved in soliciting, acquiring and managing private sector electricity purchase contacts and multiple contact points with the proponents. In April 2001, an interconnection office had been established as a single point of contact with the IPP client. Further reductions in the number of contact points with the IPP, and internal participants would be beneficial.

3a. Governance and Organizational Structure

Recommendations	Management Action Plans
❑ Continue to consolidate and integrate functions to more effectively coordinate resources and manage the IPP process. In the review of the process, consider reducing the number of contact points with IPPs.	❑ Structural changes have been made to align key functions into one Acquisition Group in Energy Management. Consolidation and integration of key functions and resources will be coordinated and the new structure communicated to key players. Completion by May 31, 2003.
❑ Clarify and document roles, responsibilities and authorities of the key players in the process and reassess resource levels, allocations and skills going forward to meet growth.	❑ Management will define and document roles and responsibilities of key players for the overall acquisition function. Staff resource levels, and skill development area gaps will be assessed to harmonize and deliver on the required functions. Completion by April 30, 2003.
❑ Formalize, clearly articulate and communicate the governance process for IPP projects to staff.	❑ The governance structure for IPP projects will be documented and communicated to all staff. Completion by June 15, 2003.
❑ Ensure compliance with the financial responsibility policy requirements and intent. Consider a control sheet to track signoff of key approval and decision milestones.	❑ The energy acquisition group will ensure that financial policy is complied with effective immediately. A process to coordinate and track approval requirements will be established by August 31, 2003.

3b. Contract Commitment Process

- Over the past decade, BC Hydro's knowledge and experience in negotiating Energy Purchase Agreements has increased. The process continues to evolve with each request for qualification and tender and the result is that the process has become more streamlined, the transaction time has reduced, the process has become more transparent and the commercial terms have strengthened.
- Some of these changes started in late 2000, as BC Hydro began to make changes to the way it managed the front end process leading up to the signing of Electricity Purchase Agreements. Notable improvements included:
  - The use of a portfolio approach to soliciting ongoing private sector interest.
  - Reducing the process to two stages; a qualification stage and a call for tender stage based on a new standard Electricity Purchase Agreement with fixed or competitive pricing.
- A review of process documentation for three projects: Island Cogeneration (1998); Purcell (1998); and Hystad Creek (2001); identified the following:
  - There was no formal statement of objectives, strategy, negotiating principles or project plan (as required for a capital project) outlined to guide the acquisition team.
  - There were too many participants developing the contract terms with the result that roles became confused and activities uncoordinated. There was a need to focus the responsibility for this activity and manage the participation, mix and continuity of the individuals necessary to provide input.
  - The qualification/bid evaluation team should have included expanded involvement of other BC Hydro groups to further increase transparency and allow equal input from all relevant parties.

3b. Contract Commitment Process

- Documentation control throughout the IPP process requires improvement. Original records and information are dispersed among various groups with no disciplined central record or master set of documents related to IPP contracts, making compilation of legal and contract documents difficult.

Recommendations	Management Action Plans
Document formal statement of objectives, or project plan with strategies and negotiating principles, to guide the acquisition team.	Management agrees and will develop and document formal statement of objectives and principles to guide the development of project plans for execution of future calls. Completion by December 31, 2003.
Set up a definite core team responsible to manage the development of contract terms, with the ability to expand representation as required and ensure continuity of participation.	Identify key functions required on core team, and appoint core team individual and alternates to manage the development of contract terms. Assign roles and responsibilities for contract development. Completion by March 31, 2003.

3b. Contract Commitment Process

Recommendations	Management Action Plans
❑ Continue to expand the team members engaged in the in qualification/bid evaluations by adding independent members to participate in the process to reduce conflict of interest issues.	❑ Recently, qualification and bid evaluations were conducted by sub-teams comprising 5-8 members from Acquisition, Finance, Legal, Generation Environment, and Energy Management, to ensure comprehensive reviews on key elements of bid submissions. Independent advisory services (PWCoopers) were retained to support the financial capability assessments. Ongoing efforts.
❑ Set up a disciplined "central records" system and retain a master set of all IPP contract information and documentation for the entire IPP lifecycle (all stages).	❑ Develop a comprehensive hardcopy and electronic repository for IPP documentation and records. Document procedures for document control/filing and communicate procedures and process to all staff. Regularly inspect the records system to implement process improvements. Completion by June 30,2003.

3c. Construction and Interconnection Process

Risk Transfer

- After the signing of the EPA, the proponent assumes full responsibility and the associated risks to build and bring the generating facility into service. These include :
  - Approval of Finance, regulatory and environmental permits and licences;
  - Professional expertise to design, project manage and build the generation facility; and
  - Satisfy technical requirements for Generator Interconnection.
- There is always the risk that the project may be delayed, cancelled or fail to come to fruition. The latest BC Hydro model agreement specifies a legal requirement for the IPP to submit regular progress status reports. BC Hydro has assumes an arms length monitoring role and to the extent that it is able, assists the proponent to navigate towards a successful completion.
- Going forward, BC Hydro should establish a database for the success rate to facilitate the planning process for estimating the amount of IPP capability to be invited in future calls.

Generator Interconnections

- Generator interconnections is a well established, mature process in BC Hydro that involves; determining the technical and economic feasibility of the interconnection, securing service agreements with BC Hydro and implementing the interconnection. BC Hydro is technically conservative and there is recognition that the process to determine economic feasibility of interconnections become more transparent.
- Recent improvements to this process include :
  - Establishing the Office of Generator Interconnection as a single point of contact for Interconnection services and providing online process and technical guidelines.

3c. Construction and Interconnection Process

- Updating BC Hydro's comprehensive set of technical requirements that IPP's have to follow to Interconnect to the Integrated Electric system.
- To reduce the cost risk to the IPP, BC Hydro has committed to firm estimates for Interconnection service within a 30% tolerance.

- Service agreements and legal terms were strengthened by introducing:
  - A Facilities Agreement (FA) to more accurately define responsibilities of both parties for equipment procurement, construction and installation.
  - A stand-alone Interconnection Agreement (IA) setting out the operating and technical arrangements for generators synchnonized to the BC Hydro system. This was previously incorporated as part of the Electricity Purchase Agreement (EPA)
- Review of the major clauses in the agreements associated with IPPs found significant lack of uniformity among them. Inconsistencies and ommissions with clauses between different agreements could lead to future contract interpretation disputes or problems.

Recommendations	Management Action Plans
Establish a database for the success rate of IPPs coming on stream to use as a benchmark to invite future energy calls for the required capacity.	Develop an energy management information system to capture key data/success indicators to support energy planning, acquisition targets and future energy calls. Completion by December 31, 2003.
Make the various IPP Agreements uniform to the extent possible to minimize contract interpretations or omissions.	Management agrees and will work with Legal to align the various IPP Agreements. Completion September 30, 2003

3d. Contract Management Process

- We reviewed the energy purchase costs, contract documents and correspondence related to four in-service Independent Power Producers executed in the 1990's: Island Co- Generation (240MW), North West Energy (58MW), Mamquam (60MW) and Soo River (12MW). Testing included financial completeness, accuracy, authorization, and compliance with contract terms and conditions as well as review of operational issues.

Financial Compliance with Contract Terms

- Overall, the financial management of the IPP contracts is effective and in accordance with the terms of the respective agreements. Management of payments is professional, well documented and there was evidence of adequate management controls.
- The larger IPPs submit invoices which are recalculated and verified, while for the majority of existing smaller IPPs, BC Hydro prepares the payment statements. This practice is to be discontinued with new IPPs as the standard EPA transfers risk and requires the proponent to provide detailed invoice statements. All payment statements are reviewed and authorized, and samples of payments were found to be arithmetically correct.
- For some larger IPPs there are annual flow through costs that can be significant and it is prudent to undertake cost audits at least each 3-5 years. Management last undertook a cost audit of NW Energy flow through costs in 1997.

Structure of Agreements

- Aside from the necessary differences due to different technologies, the four in-service IPP agreements differ significantly in the wording from usual common legal clauses.

3d. Contract Management Process

- Comparing the sampled bilaterally negotiated agreements to the new EPA, the standard contract includes significant improvements that address deficiencies in existing agreements such as:
  - Provision for liquidated damages;
  - Provision for reimbursement and remedies on termination; and
  - Specifies limits of liability and indemnity.
- The improvements stem from a change in policy towards more commercial terms. Compared to other model EPA's (approved by major lenders) these standard EPAs' appear to generally balance the risks between the IPP and BC Hydro, with some risk transferred to the Insurer.

Operations

- Financial management between BC Hydro and the IPP's is effective. However the responsibility for contract management and administration within BC Hydro is distributed among numerous groups and there is a need to consolidate coordination.
- The Island Cogeneration Plant (ICP) has only been in operation for eight months so a comprehensive assessment is premature. However management of ICP appears professional and proactive. Currently there is a risk that adequate gas supply will be unavailable to the Power Plant, due to expiry of a supply agreement with Centra Gas. BC Hydro is negotiating an extension to the gas transportation agreement to cover the period until the completion of the Georgia Strait Crossing gas pipeline to the Island.

3d. Contract Management Process

- The following issues were noted:
  - The status of insurance for the IPPs audited is unknown. The agreements specify risks transferred to the insurer, but BC Hydro has no evidence that the insurance guarantees were purchased or are sufficient.
  - There are no records of operating committee minutes or of plant operating and maintenance records for three of the four IPP plants audited.
  - BC Hydro does not normally inspect the general condition of IPP plants and accesses plants infrequently and for limited purposes, such as checking the metering systems. (ICP has not been in operation long enough to audit this.)

IPP Experience and Performance

- BC Hydro's experience with the IPPs were reviewed with the following conclusions:
  - Technical performance - has been satisfactory but variable. Soo River and NW Energy are performing satisfactorily. Energy from Mamquam has been declining below the committed amount for the past five years. The Island Cogeneration Plant is below committed capacity because of some design problems in its first year of operation.
  - Cost performance - Satisfactory as there are no significant disputes or payment issues.
  - Commercial contract conformance - IPPs generally are conforming to the commercial requirements of the contract to the extent that we are able to determine. BC Hydro has not availed itself of all of its rights within the contracts and there is a need for a better understanding of all these rights and reasons for exercising.

3d. Contract Management Process

Recommendations	Management Action Plans
❑ Strengthen the coordination of contract management to ensure all requirements of the contracts and all issues between BC Hydro and the IPP are properly addressed. Consider options for coordination of the various functions associated with contract management of IPP's to provide a single point of contact.	❑ Develop a new Contract Management structure/process to formalize and document current functions and roles to ensure cradle to grave management of contract issues and relationships with the project/proponents. Conclude a Service Agreement with Generation for service, reporting and corrective action of contracted energy dispatch/control. Completion April 30, 2003.
❑ Obtain insurance certificates to ensure sellers meet their ongoing obligations in terms of risk coverage.	❑ Contract Management to execute in accordance with EPA provisions. Completion by August 31, 2003 and ongoing.
❑ Exercise rights by obtaining, copies of operating and maintenance records, and reviewing logs and minutes of operating committee meetings. Record should be kept on file.	❑ Develop a system to track the fulfillment of contract requirements, review of key information to exercise rights and retention of records for ongoing performance management under the EPA by October 31, 2003
❑ BC Hydro should inspect plants, on a risk-based schedule, to check that the general condition of the plants is consistent with the annual inspection report, to verify that the deficiencies identified in the annual inspection report have been addressed and to check the numbers and qualifications of personnel.	❑ Develop and implement a risk-based system for inspections including: a schedule for inspections, inspection checklists, roles and responsibilities for inspections, reporting, and continual improvement by December 31, 2003.

19.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: BC Hydro Energy Procurement Processes
Exhibit B-7, CEC IR 3.2; Exhibit B-5, BCUC IR 42.1.1, BCUC IR 42.5;
Merrimack Report, pp. 5, 47; BC Hydro Overview of BC Hydro's Energy Procurement Practices (Energy Procurement Practices Overview) dated November 2013, p. 2[1]
Energy Procurement Principles

BC Hydro states in response to Commercial Energy Consumers Association of British Columbia (CEC) IR 3.2 that it "… has not developed a process to identify the lowest cost contracts within the EPA renewal portfolio prior to entering into negotiations with specific IPP projects." BC Hydro further states in response to BCUC IR 42.1.1 that the total cost forecast from the 10-Year-Rates Plan has been used to provide a financial framework and budget within which to manage the costs for all EPA renewals.

BC Hydro states in response to BCUC IR 42.5 that it does not anticipate that an analysis of energy procurement processes will be carried out in preparation for the next IRP.

The Merrimack Report recommends on page 5 that BC Hydro develop standards for evaluating and negotiating bilateral contracts and make the standards transparent to stakeholders. On page 47 the report recommends that BC Hydro develop project viability criteria and transparent weightings for price and non-price factors to evaluate bids and select procurements.

BC Hydro describes its energy procurement principles in its Energy Procurement Practices Overview dated November 2013 and includes on page 2 the following principles:

- Cost-effectiveness – enter into contracts with proponents which provide cost-effective electricity that benefits BC Hydro's ratepayers, and
- Transparency – provide clear information on procurement requirements including eligibility, fees, evaluation criteria and selection of projects.

[1] BC Hydro, Overview of BC Hydro's Energy Procurement Practices (November 2018) https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/energy-procurement-practices.pdf

2.19.4 Does BC Hydro consider that improvements could be made in its approach to its energy procurement processes as related to EPA renewals (specifically, with regard to cost-effectiveness and transparency principles)? Please explain.

RESPONSE:

BC Hydro is of the view that its approach to its energy procurement processes, as related to recent EPA renewal bilateral negotiations, have adequately met BC Hydro's cost effective and transparency principles. Please refer to BC Hydro's response to BCUC IR 2.19.1 explaining why BC Hydro believes it has met its cost-effectiveness and transparency principles. Nevertheless, it is possible that improvements could be identified for such processes.

19.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: BC Hydro Energy Procurement Processes
Exhibit B-7, CEC IR 3.2; Exhibit B-5, BCUC IR 42.1.1, BCUC IR 42.5;
Merrimack Report, pp. 5, 47; BC Hydro Overview of BC Hydro's Energy Procurement Practices (Energy Procurement Practices Overview) dated November 2013, p. 2[1]
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[1] BC Hydro, Overview of BC Hydro's Energy Procurement Practices (November 2018) https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/energy-procurement-practices.pdf

2.19.4 Does BC Hydro consider that improvements could be made in its approach to its energy procurement processes as related to EPA renewals (specifically, with regard to cost-effectiveness and transparency principles)? Please explain.

2.19.4.1 Does BC Hydro consider there could be benefit from a third party review of BC Hydro's EPA renewal practices (similar to the 2011 Merrimack report)? If not, please explain.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.19.4.

19.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: BC Hydro Energy Procurement Processes
Exhibit B-7, CEC IR 3.2; Exhibit B-5, BCUC IR 42.1.1, BCUC IR 42.5;
Merrimack Report, pp. 5, 47; BC Hydro Overview of BC Hydro's Energy Procurement Practices (Energy Procurement Practices Overview) dated November 2013, p. 2[1]
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BC Hydro describes its energy procurement principles in its Energy Procurement Practices Overview dated November 2013 and includes on page 2 the following principles:

- Cost-effectiveness – enter into contracts with proponents which provide cost-effective electricity that benefits BC Hydro's ratepayers, and
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[1] BC Hydro, Overview of BC Hydro's Energy Procurement Practices (November 2018) https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/energy-procurement-practices.pdf

2.19.5 Please explain whether key inputs involved in pricing EPA renewals (specifically, load resource balance, Mid-C forecast, new-generation cost estimate and the Delivery Price Adjustment Table) need to be kept confidential, and whether they are kept confidential in BC Hydro's IRP.

RESPONSE:

BC Hydro has considered the disclosure of confidential information in a careful and reasoned manner while balancing the interests of transparency and procedural fairness with the equally important objective of ensuring that commercially sensitive and confidential financial information remains protected from wide disclosure which could result in harm to both BC Hydro and its ratepayers.

BC Hydro has determined that the LRB, new-generation cost estimate and the generic delivery price adjustment table will be made public, subject to the protection of any underlying commercially sensitive and confidential financial information.

The Mid-C forecast contains information proprietary to ABB and BC Hydro is subject to non-disclosure obligations in our agreement with ABB. It is BC Hydro's understanding this information is highly confidential to ABB and public disclosure of this information would be harmful to their commercial interests. Therefore, the detailed Mid-C Forecast will be kept confidential.

20.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: BC Hydro Energy Procurement Processes
Exhibit B-5, BCUC IR 42.1.1
EPAs with Evergreen Provisions

In BCUC IR 42.1.1 response, BC Hydro states for those EPAs with "evergreen" provisions, BC Hydro has been deferring renewal of EPAs for smaller hydroelectric projects and focusing negotiation of EPA renewals with larger hydroelectric projects.

2.20.1 Please provide a list of EPAs that BC Hydro could terminate, their most recent annual energy volumes and most recent annual energy cost (in $ and average $/MWh), and explain why BC Hydro has not terminated them.

RESPONSE:

The public version of this response has been redacted to maintain in confidence commercially sensitive information.as public disclosure could impact BC Hydro's ongoing negotiations related to EPAs.

BC Hydro continually monitors its portfolio of EPAs to ensure that IPPs are in compliance with the terms of their agreements and to consider exercising termination rights when such rights arise. At this time, there is one EPA which BC Hydro has identified as an agreement where we may wish to exercise our termination rights. [redacted]

Please also refer to BC Hydro's response to BCUC IR 2.15.1 which provides a summary of those EPAs which are expected to expire prior to BC Hydro's submission of its 2021 IRP by February 28, 2021.

21.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: BC Hydro Energy Procurement Processes
Exhibit B-7, CEC IR 1.2; Zapped: A Review of BC Hydro's Purchase of Power from IPPs conducted for the Minster of Energy, Mines and Petroleum Resources (Zapped Report) dated February 2019, p. 69[1]
Market value of energy

BC Hydro states in response to CEC IR 1.2 that, in evaluating the EPAs, it considered BC Hydro's avoided cost as the upper benchmark of cost-effectiveness, and also took into consideration the IPP's opportunity cost (based on the BC border sell price), and an estimate of the IPP's cost of service (including a rate of return).

The Zapped Report, a review of BC Hydro's purchase of power from IPPs conducted for the Minster of Energy, Mines and Petroleum Resources, states on page 69:

BC Hydro is a Commercial Crown corporation and should do nothing more or less than act in a commercial manner. Any offer of a renewal rate that is negotiated based on the IPPs cost of service and a rate of return, rather than the market value of the energy produced, is a non-commercial act; it is somewhat equivalent to a guarantee of future profit for the out of province investor who now owns the project. BC Hydro should establish one reasonable commercial proposition, define that proposition in appropriate detail and present it as the only commercial offer BC Hydro will make to investors holding a maturing IPP generating Intermittent energy.

2.21.1 Does BC Hydro agree with the extract from the Zapped Report included above? Please explain.

RESPONSE:

BC Hydro does not believe it is appropriate to comment on the conclusions or the methodology of the report. The Zapped Report was commissioned by the Minister of Energy, Mines & Petroleum Resources to review BC Hydro's power acquisitions and provides an independent assessment of government policy. While BC Hydro provided background data and information to the consultant, the consultant developed his own independent analysis, conclusions and recommendations.

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[1] Zapped: A Review of BC Hydro's Purchase of Power from IPPs conducted for the Minster of Energy, Mines and Petroleum Resources (February 2019) https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bch19-158-ipp_report_february_11_2019.pdf

21.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: BC Hydro Energy Procurement Processes
Exhibit B-7, CEC IR 1.2; Zapped: A Review of BC Hydro's Purchase of Power from IPPs conducted for the Minster of Energy, Mines and Petroleum Resources (Zapped Report) dated February 2019, p. 69[1]
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2.21.2 Does BC Hydro consider that there are market barriers (such as lack of information or an overly complex process to export energy) preventing the IPPs in this Application from achieving market value for their energy should BC Hydro not renew their respective EPAs? If yes, please describe.

[1] Zapped: A Review of BC Hydro's Purchase of Power from IPPs conducted for the Minster of Energy, Mines and Petroleum Resources (February 2019) https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bch19-158-ipp_report_february_11_2019.pdf

RESPONSE:

No. BC Hydro does not believe there are barriers to accessing wholesale electricity markets. Similar to U.S. transmission service providers, BC Hydro has an Open Access Transmission Tariff that sets out what type and how parties can reserve transmission service within and out of the BC Hydro transmission system for deliveries to U.S. and Alberta markets. The requirements for participation in the Alberta market are easily accessible from the Alberta Electric System Operator website. The National Energy Board's requirements for applying for Electricity Export Permits to the U.S. are laid out on the National Energy Board's website. BC Hydro notes that numerous parties participate in wholesale electricity markets in Alberta and the U.S. on a regular basis, including IPPs based in Canada and the U.S., and there are numerous entities such as lawyers and consultants that can advise on the process.

The ability to achieve any particular market value is dependent upon the respective generation output profile and the type and level of investment in transmission service chosen by the party.

21.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: BC Hydro Energy Procurement Processes
Exhibit B-7, CEC IR 1.2; Zapped: A Review of BC Hydro's Purchase of Power from IPPs conducted for the Minster of Energy, Mines and Petroleum Resources (Zapped Report) dated February 2019, p. 69[1]
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2.21.2 Does BC Hydro consider that there are market barriers (such as lack of information or an overly complex process to export energy) preventing the IPPs in this Application from achieving market value for their energy should BC Hydro not renew their respective EPAs? If yes, please describe.

2.21.2.1 To the extent that market barriers are identified, please explain the options for BC Hydro to mitigate these market barriers, and whether the options identified would result in significant costs to ratepayers.

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[1] Zapped: A Review of BC Hydro's Purchase of Power from IPPs conducted for the Minster of Energy, Mines and Petroleum Resources (February 2019) https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bch19-158-ipp_report_february_11_2019.pdf

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.21.2 for a discussion regarding market access for IPPs.

22.0 E. BC ENERGY POLICY

Reference: BC ENERGY POLICY ISSUE
Exhibit B-1-1-2, p. 26; *Utilities Commission Act*, RSBC 1996, c 473;
Exhibit B-6, BCUC IR 3.1
UCA filing requirements

BC Hydro states on page 26 of the Application that it entered into a Forbearance Agreement with an effective date of April 1, 2014, where it agreed to forebear from exercising its right to terminate the Walden North EPA.

Section 68 of the *Utilities Commission Act* (UCA) states:

> "energy supply contract" means a contract under which energy is sold by a seller to a public utility or another buyer, and includes an amendment of that contract, but does not include a contract in respect of which a schedule is approved under section 61 of this Act."

2.22.1 Please provide, if possible, a public version of BC Hydro's response to confidential BCUC IR 3.1.

RESPONSE:

Portions of the background information provided by the BCUC as preamble to its BCUC CONF IR 1.3.1 included information that BC Hydro considers confidential. As a result, BC Hydro is only including in this response the question asked by the BCUC in BCUC CONF IR 1.3.1 and BC Hydro's response to that IR.

The question asked was,

1.3.1 Please explain why the Forbearance Agreement was never filed for acceptance with the BCUC.

BC Hydro's response was as follows:

> **"The Forbearance Agreement was not filed pursuant to section 71 of the UCA because it is a stand-alone commercial arrangement entered into by the parties and does not constitute an energy supply contract or an amendment to an energy supply contract.**

Under the terms of the Forbearance Agreement, BC Hydro agreed to refrain from exercising its right to terminate the EPA for a period of time in consideration of payments being made to BC Hydro. Notwithstanding this arrangement, the EPA continues to exist, unamended, during the term of the Forbearance Agreement and will continue to exist, unamended, following the expiry of the Forbearance Agreement."

22.0 E. BC ENERGY POLICY

Reference: BC ENERGY POLICY ISSUE
Exhibit B-1-1-2, p. 26; *Utilities Commission Act*, RSBC 1996, c 473;
Exhibit B-6, BCUC IR 3.1
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Section 68 of the *Utilities Commission Act* (UCA) states:

> "energy supply contract" means a contract under which energy is sold by a seller to a public utility or another buyer, and includes an amendment of that contract, but does not include a contract in respect of which a schedule is approved under section 61 of this Act."

2.22.2 Does BC Hydro consider the Forbearance Agreement an amendment to the EPA for the purpose of section 68 of the UCA? Please explain.

RESPONSE:

BC Hydro does not consider the Forbearance Agreement to be an amendment to the Walden North EPA for the purpose of section 68 of the UCA. A forbearance agreement is a common, stand-alone form of commercial agreement where one party agrees to forbear from exercising a right in exchange for consideration from the other party. The contract in which the original rights are set out continues to exist, unamended, during the term of forbearance.

22.0 E. BC ENERGY POLICY

Reference: BC ENERGY POLICY ISSUE
Exhibit B-1-1-2, p. 26; *Utilities Commission Act*, RSBC 1996, c 473;
Exhibit B-6, BCUC IR 3.1
UCA filing requirements

BC Hydro states on page 26 of the Application that it entered into a Forbearance Agreement with an effective date of April 1, 2014, where it agreed to forebear from exercising its right to terminate the Walden North EPA.

Section 68 of the *Utilities Commission Act* (UCA) states:

> "energy supply contract" means a contract under which energy is sold by a seller to a public utility or another buyer, and includes an amendment of that contract, but does not include a contract in respect of which a schedule is approved under section 61 of this Act."

2.22.2 Does BC Hydro consider the Forbearance Agreement an amendment to the EPA for the purpose of section 68 of the UCA? Please explain.

2.22.2.1 Does BC Hydro consider that, if a Forbearance Agreement is not accepted under section 71 of the UCA, resultant costs (if found to not be in the public interest) could be disallowed under sections 58–64 of the UCA? Please explain.

RESPONSE:

In BC Hydro's view, the Forbearance Agreement does not need to be filed under section 71 of the UCA as it is not an energy supply contract as defined in section 68 of the UCA. No energy is being purchased or sold under the Forbearance Agreement. Please refer to BC Hydro's response to BCUC IR 2.22.2 for further discussion of BC Hydro's views with respect to the status of the Forbearance Agreement.

BC Hydro is not incurring any costs pursuant to the Forbearance Agreement, so there are no costs that could be subject to disallowance in relation to this question. BC Hydro notes that the costs it is incurring pursuant to the Walden North EPA (whether or not the Forbearance Agreement is in effect) are recoverable pursuant to section 4(1)(b) of Direction No. 8 to the BCUC.

22.0 E. BC ENERGY POLICY

Reference: BC ENERGY POLICY ISSUE
Exhibit B-1-1-2, p. 26; *Utilities Commission Act*, RSBC 1996, c 473;
Exhibit B-6, BCUC IR 3.1
UCA filing requirements

BC Hydro states on page 26 of the Application that it entered into a Forbearance Agreement with an effective date of April 1, 2014, where it agreed to forebear from exercising its right to terminate the Walden North EPA.

Section 68 of the *Utilities Commission Act* (UCA) states:

> "energy supply contract" means a contract under which energy is sold by a seller to a public utility or another buyer, and includes an amendment of that contract, but does not include a contract in respect of which a schedule is approved under section 61 of this Act."

2.22.3 Please describe the type of amendments that BC Hydro might typically make to energy supply contracts that would come before the BCUC for section 71 review.

RESPONSE:

BC Hydro files all amendments to non-exempt EPAs pursuant to section 71 of the *Utilities Commission Act* either as part of its quarterly filings with the BCUC or as a separate application in some circumstances. For example, if the seller wishes to change the description of their plant as defined in the EPA or if the seller wishes to change its point of interconnection as defined in the EPA, BC Hydro would file such amending agreements with the BCUC pursuant to section 71 of the *Utilities Commission Act*.

If the EPA provides for a party to exercise a right which is included within the terms of the EPA, with agreement of the other party, BC Hydro views these agreements as contractual developments (not amendments) as provided under section 2 of the BCUC's Rules for Energy Supply Contracts for Electricity (Appendix A to BCUC Order No. G-61-12). These agreements are noted as contractual developments in our quarterly filings with the BCUC and are filed for information purposes only.

BC Hydro notes that amendments and contractual developments related to EPAs that are not required to be filed pursuant to section 71 of the *Utilities Commission Act* in accordance with legislation or regulations are not filed with the BCUC.

22.0 E. BC ENERGY POLICY

Reference: BC ENERGY POLICY ISSUE
Exhibit B-1-1-2, p. 26; *Utilities Commission Act*, RSBC 1996, c 473;
Exhibit B-6, BCUC IR 3.1
UCA filing requirements

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> "energy supply contract" means a contract under which energy is sold by a seller to a public utility or another buyer, and includes an amendment of that contract, but does not include a contract in respect of which a schedule is approved under section 61 of this Act."

2.22.4 Please explain why BC Hydro treated the Walden North Forbearance Agreement as a stand-alone agreement, and not an amendment to the original EPA. Is it standard practice? Has BCH done this before?

RESPONSE:

Please refer to BC Hydro's response to BCUC IRs 2.22.1 and 2.22.2 for a further discussion with respect to BC Hydro's views on forbearance agreements and the application of this analysis to the Walden North Forbearance Agreement.

BC Hydro does not have a standard practice with respect to using forbearance agreements. Generally, BC Hydro would use a forbearance agreement if the appropriate circumstances arose. For example, if the seller requests BC Hydro to forbear, or refrain, from exercising a certain right under a contract, BC Hydro may agree to such a request in exchange for consideration.

BC Hydro has entered into forbearance arrangements in different contexts for different EPAs. For example, BC Hydro has entered into forbearance agreements in the EPA context where we agreed to forbear from exercising termination rights that may arise under certain circumstances (e.g., failure of the IPP to achieve commercial operation by a specified date) in consideration of the IPP delaying their commercial operation to a future date. The Walden North Forbearance Agreement deals with BC Hydro's termination right related to the evergreen

provision of an EPA (i.e., the existing original Walden North EPA has an evergreen provision that provides it will continue on a year to year basis, after its initial contract term, unless terminated in accordance with the terms of the EPA). There are no other IPPs with evergreen EPAs that have a forbearance arrangement similar to the Walden North Forbearance Agreement.

23.0 E. BC ENERGY POLICY

Reference: BC ENERGY POLICY ISSUE
Exhibit B-5, BCUC IR 23.1; Exhibit B-1-1-2, p. 16;
Exhibit B-5-1, BCUC IR 6.1, IR 33.3
Wealth transfers

BC Hydro states in response to BCUC IR 23.1 that IPP water rentals and taxes are included in its cost-effectiveness analysis. In the Application BC Hydro states that it is uncertain whether the Sechelt Creek facility would be decommissioned or decommissioned earlier in the event the EPA is not renewed**.**

2.23.1 Please discuss whether preventing an IPP from shutting down its operation is a consideration for BC Hydro when entering into EPA renewals with IPPs.

RESPONSE:

In considering whether to enter into an EPA renewal with an IPP, BC Hydro considers the benefits associated with the continuing operation of the IPP facility. The benefits primarily considered are the supply of cost effective energy for BC Hydro's ratepayers and support for applicable legislation and government policy and direction.

23.0 E. BC ENERGY POLICY

Reference: BC ENERGY POLICY ISSUE
Exhibit B-5, BCUC IR 23.1; Exhibit B-1-1-2, p. 16;
Exhibit B-5-1, BCUC IR 6.1, IR 33.3
Wealth transfers

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2.23.1 Please discuss whether preventing an IPP from shutting down its operation is a consideration for BC Hydro when entering into EPA renewals with IPPs.

2.23.1.1 If so, in determining whether it is in the public interest to enter into an EPA renewal that prevents an IPP from shutting down, does BC Hydro consider that the EPA cost should be reduced by the IPP's: (i) total contributions to the BC GDP, (ii) water rentals, and/or (iii) taxes paid? Please explain.

RESPONSE:

No. Please refer to BC Hydro's response to BCUC IR 2.23.1.

23.0 E. BC ENERGY POLICY

Reference: BC ENERGY POLICY ISSUE
Exhibit B-5, BCUC IR 23.1; Exhibit B-1-1-2, p. 16;
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2.23.1 Please discuss whether preventing an IPP from shutting down its operation is a consideration for BC Hydro when entering into EPA renewals with IPPs.

2.23.1.1 If so, in determining whether it is in the public interest to enter into an EPA renewal that prevents an IPP from shutting down, does BC Hydro consider that the EPA cost should be reduced by the IPP's: (i) total contributions to the BC GDP, (ii) water rentals, and/or (iii) taxes paid? Please explain.

2.23.1.1.1 Please explain whether BC Hydro considers that, if such an adjustment is made, it should only be for the years that BC Hydro is in a surplus situation (on the basis that new generation projects would have similar or greater economic benefits). Please explain.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.23.1.1.

23.0 E. BC ENERGY POLICY

Reference: BC ENERGY POLICY ISSUE
Exhibit B-5, BCUC IR 23.1; Exhibit B-1-1-2, p. 16;
Exhibit B-5-1, BCUC IR 6.1, IR 33.3
Wealth transfers

2.23.2 Does BC Hydro take into consideration the full amortization of the IPPs capital assets in determining the price of EPA renewals?

RESPONSE:

Yes. In negotiating EPA renewals, BC Hydro expects that the IPP's initial capital investment is likely to have been fully or largely recovered during the term of the original EPA. BC Hydro notes that the IPP may have made recent capital investments to its existing facility, which may not be fully amortized at the time of the EPA renewal.

24.0 E. BC ENERGY POLICY

Reference: Load Resource Balance
Site C Inquiry Report, Appendix C, p.2; Exhibit B-5, BCUC IR 8.4, 11.2.2.1
Before vs. after planned resources

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BC Hydro states in response to BCUC IR 11.2.2.1 that the LRB before planned resources is applicable because all planned resources, including EPA renewals, are not committed. BC Hydro also states that the renewal assumption for seven biomass projects has increased from 50 percent to 80 per cent for energy, and that volumes under the Standing Offer Program (SOP) have been reduced, with the exception of four First Nations clean energy projects and three other potential EPAs related to Impact Benefit Agreements with First Nations. In BCUC IR 8.4, BC Hydro uses 2034 as the date to switch from DSM/EPA renewals to greenfield wind energy in estimating its long run marginal cost.

2.24.1 Please identify the resources that are included in the 'after planned resource' LRB but not the 'before planned resource' LRB.

RESPONSE:

Resources that are included in the 'after planned resource' LRB but not the 'before planned resource' LRB are as follows:

- **All future IPP EPA renewals not yet executed and/or accepted by the BCUC; for example, the planned renewals for the three projects in this Application as well as the biomass projects under the Biomass Energy Program;**
- **Four First Nations clean energy projects under the SOP that were announced March 14, 2018[1] as well as three other potential EPAs related to Impact Benefit Agreements with First Nations;**
- **Revelstoke Unit 6; and**
- **DSM savings associated with Rates and Programs in fiscal 2020 and beyond.**

[1] **The announcement included five First Nations clean energy projects, but one of the agreements was executed on October 1, 2018.**

24.0 E. BC ENERGY POLICY

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2.24.1 Please identify the resources that are included in the 'after planned resource' LRB but not the 'before planned resource' LRB.

2.24.1.1 Please identify any resources on this list that BC Hydro considers would not reasonably be displaced by the EPAs included in this Application. For example, does BC Hydro consider that Revelstoke 6 or planned EPAs supporting government priority policy items are viable alternatives to EPAs included in this Application? Please explain.

RESPONSE:

Evaluation of alternatives - which also include DSM alternatives, EPA renewals, and investments in heritage assets - for meeting BC Hydro's supply obligations and other objectives are considered at the portfolio level in our IRP. As a result, individual resources within the portfolio of planned resources (i.e., the resources identified in BC Hydro response to BCUC IR 2.24.1) are not displaced if the three EPAs from this Application are accepted and become committed resources.

The 2013 IRP recommended action to pursue cost-effective EPA renewals was established, taking into account the assumed costs and expected benefits

(e.g., financial, social, environmental and system impacts) of EPA renewals in comparison with other potential resource options, which included DSM, investment in existing BC Hydro generation assets and renewable greenfield IPPs. Based on the benchmark LRMC prices for DSM and EPA renewals and greenfield IPP supply established in the 2013 IRP, the EPA renewal portfolio in general represented cost-effective potential resources compared to greenfield IPP resources.

In implementing the 2013 IRP recommended action for EPA renewals, IPP projects have been individually assessed for need and for cost-effectiveness as they come up for renewal. In general, the assessment of cost-effectiveness has been relative to BC Hydro's opportunity cost which considered market prices during periods of LRB surplus and the above benchmark LRMC prices in periods of LRB deficit.

As discussed in BC Hydro's response to BCUC IR 1.8.4, BC Hydro's last estimate of the cost of greenfield IPPs (i.e., LRMC) is out of date. A preliminary analysis of wind costs in B.C. suggest costs have decreased. BC Hydro has adopted an interim assumption to use market price to value energy during surplus and deficit periods.

Please refer to BC Hydro's response to BCUC confidential IR 2.9.1 for the quantitative analysis of the cost-effectiveness of the three EPA renewals in this Application relative to BC Hydro's opportunity cost reflecting the interim market price approach discussed above and the approach used in the Application, with a number of different scenarios for the potential cost of greenfield IPPs.

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2.24.1 Please identify the resources that are included in the 'after planned resource' LRB but not the 'before planned resource' LRB.

2.24.1.2 Does BC Hydro consider that it would be reasonable to include the resources identified above in the LRB used to evaluate EPAs in this Application in order to mitigate the risk of oversupply? Please explain.

RESPONSE:

No, BC Hydro does not consider this approach to be reasonable for evaluating the EPAs in this Application. An evaluation of all potential resource options to meet long-term resource adequacy needs is conducted as part of the IRP, in which the merits of resource portfolios are compared. The selected resource portfolio as a whole is deemed the appropriate approach to meeting long-term resource adequacy as well as other objectives. Individual resources within the resource portfolio are tested against evaluation criteria appropriate at the time of final execution, as is the case of these EPAs in this Application. The resources identified in BC Hydro response to BCUC IR 2.24.1 that are subject to review will be similarly evaluated at the appropriate time. It would be premature to evaluate the EPAs in this Application against potential future planned resources.

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2.24.2 For table 3 and 4 provided in response to BCUC IR 11.2.2.1, please provide a break-down of the estimated IPP renewal volumes for each year from F2020 to F2036 between: (i) EPAs the BC Hydro plans to renew regardless of the outcome of this Application, and (ii) other EPAs.

RESPONSE:

The outcome of this Application does not impact any of the renewal assumptions for planned resources and hence there is no difference between i and ii in the question. The total annual planned renewal volume for energy is provided on line 3 of Table 3 in BC Hydro's response to BCUC IR 1.11.2.2.1, and for capacity it is provided on line 3 of Table 4 in the same response.

24.0 E. BC ENERGY POLICY

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2.24.3 Please explain whether BC Hydro used before or after planned resources for the purpose of developing its long-run marginal cost estimate as used in the Application.

RESPONSE:

In the Application, two LRMC values are used. The first LRMC value is based on DSM and EPA renewals as the marginal resources and is valid for the deficit period identified in 'before planned resources' LRB. The second LRMC value is based on greenfield IPPs and is used for the deficit period identified in the 'including planned resources" LRB.