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March 15, 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
Responses to Commission Information Request No. 1

BC Hydro writes in accordance with BCUC Order No G-200-18 (Exhibit A-8), submitting its responses to Round 1 Information Requests (**IR**) as follows:

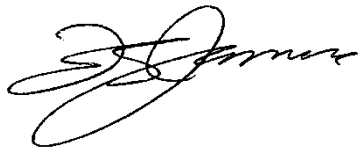
Exhibit B-5	Responses to Commission IRs (Public Version)
Exhibit B-5-1	Responses to Commission IRs (Confidential Version)
Exhibit B-6	Responses to Commission Confidential IRs (Confidential)
Exhibit B-7	Responses to Interveners IRs (Public Version)
Exhibit B-7-1	Responses to Interveners IRs (Confidential Version)

On October 16, 2018, BC Hydro sought an extension for providing its answers for round one IRs to four weeks following the release of a report with respect to the Government Review of BC Hydro (Government Review). The Comprehensive Review of BC Hydro Phase 1 Final Report was released on February 14, 2019 and is provided at this link: https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/electricity/bc-hydro-review.

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 IV 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

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Enclosure

1.0 A. BC ENERGY OBJECTIVES CONSIDERATION

Reference: FIRST NATIONS IMPACT – SECHELT CREEK HYDRO OWNERSHIP STRUCTURE
***Clean Energy Act*, Section 2(l); Exhibit B-1, Application, p. 13, p. 15**

Section (2)(l) of the *Clean Energy Act* (CEA*)* states that one of BC's energy objectives is "to foster the development of first nation and rural communities through the use and development of clean or renewable resources;"

Page 13 of the British Columbia Hydro and Power Authority (BC Hydro) Application for Electricity Purchase Agreement (EPA) Renewals for Sechelt Creek Hydro, Brown Lake Hydro and Walden North Hydro (Application) states BC Hydro's view that "…the proposed EPA renewal price reasonably represents the cost of service for the Sechelt Creek facility, including an acceptable rate of return given the risk borne by the IPP."

Page 15 of the Application states that "Earlier this year; BC Hydro was advised that the Sechelt Creek IPP and the shíshálh Nation entered into an agreement that results in collaborative decision-making and governance, and will result in shíshálh Nation equity ownership and profit sharing for the project."

1.1.1 On what date was BC Hydro advised that the Sechelt Creek (Independent Power Producer) IPP and the shíshálh Nation entered into an agreement for equity ownership and profit sharing?

RESPONSE:

BC Hydro was advised on March 27, 2017 that an equity ownership and profit sharing agreement (Facility Agreement) had been executed between the Sechelt Creek IPP and shíshálh Nation. Sechelt Creek IPP has advised BC Hydro that the effective date of the Facility Agreement is March 1, 2017.

1.0 A. BC ENERGY OBJECTIVES CONSIDERATION

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1.1.1.1 On what date did the Sechelt Creek IPP and shíshálh Nation agree to equity ownership and profit sharing, and what is the effective date of this agreement?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.1.1.

1.0 A. BC ENERGY OBJECTIVES CONSIDERATION

Reference: FIRST NATIONS IMPACT – SECHELT CREEK HYDRO OWNERSHIP STRUCTURE
***Clean Energy Act*, Section 2(l); Exhibit B-1, Application, p. 13, p. 15**

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1.1.2 Please provide an ownership structure, along with percentages, that indicates the shíshálh Nation's ownership level in the Sechelt Creek IPP.

RESPONSE:

BC Hydro does not have additional details other than what was provided in the Application. The Sechelt Creek IPP has advised BC Hydro that the ownership structure and percentages are subject to confidentiality restrictions. Please refer to the March 2017 press release for the information made publicly available at http://m.marketwired.com/press-release/capstone-infrastructure-corporation-and-shishalh-nation-sign-facility-agreement-tsx-cse.pr.a-2205631.htm.

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1.1.2.1 Please provide BC Hydro's estimate of the net present value of the income the shíshálh Nation would earn over the life of the proposed 40-year EPA period compared to a scenario where the EPA was not renewed. Please provide supporting calculations and describe all key assumptions used.

RESPONSE:

BC Hydro does not have the information to provide the requested calculations. However, the Sechelt Creek IPP has indicated to BC Hydro that if the Sechelt Creek EPA is not renewed the associated income to shíshálh Nation would decline.

Please also refer to BC Hydro's responses to BCUC IRs 1.1.2 (for the ownership structure of the IPP) and IRs 1.1.2.2 and 1.6.1 (for the other economic benefits).

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1.1.2.2 Please quantify any additional First Nations benefits to the shíshálh Nation (for example, jobs and training). Please include in your response an estimate (if available) of the number of shíshálh Nation members employed at the Sechelt Creek Hydro facility.

RESPONSE:

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

- **One member of shíshálh Nation is directly employed by the Sechelt Creek IPP on a part-time basis; and**

- **In addition to this direct employment, shíshálh Nation's Resource Management team facilitates the ongoing maintenance of the facility's man-made salmon spawning channel. shíshálh Nation's Resource Management team is comprised of four full-time staff dedicated to local environmental projects which include the spawning channel.**

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1.1.3 Please explain how much weight BC Hydro considers should be placed on the shíshálh Nation equity ownership/profit sharing arrangement for Sechelt Creek Hydro.

RESPONSE:

Relationships with First Nations are important to BC Hydro. The local First Nation community stands to benefit from this EPA renewal through its participation in the project leading to greater economic prosperity for its community.

Section 71(2.21) of the *Utilities Commission Act* specifies the factors and criteria the Commission must consider in determining whether an energy supply contract filed by BC Hydro is in the public interest. The test of what constitutes the public interest is a flexible test.

Section 71(2.21) does not specify the weight to be given to particular prescribed factors and criteria when considering whether a particular energy supply contract is in the public interest. In determining whether to enter into an EPA, BC Hydro is guided by the section 71(2.21) criteria and does not apply weighting to these criteria. Generally, we believe that it is not practical or feasible (with a reasonable

level of confidence) to apply quantitative weighting to the section 71(2.21) factors and criteria.

However, section 71(2.21) of the *Utilities Commission Act* does make clear that in determining whether an energy supply contract filed by BC Hydro is in the public interest the Commission is to consider B.C.'s energy objectives which includes "to foster the development of first nation and rural communities through the use and development of clean or renewable resources".

2.0 A. BC ENERGY OBJECTIVES CONSIDERATION

Reference: FIRST NATIONS IMPACT – WALDEN NORTH HYDRO OWNERSHIP STRUCTURE
CEA, Section 2(l); Exhibit B-1, p. 26, p. 32, pp. 34–36

Page 26 of the Application states that "In February, 2016, the Walden North project was acquired by Cayoose Creek Power Limited Partership (CCCLP), which is comprised of the Cayoose Creek Development Corporation and Innergex. The Sekw'el'was Cayoose Creek Indian Band (Cayoose Creek Indian Band) is the sole beneficial shareholder of Cayoose Creek Development Corporation."

Page 32 of the Application states BC Hydro's view that "…the proposed EPA renewal price reasonably represents Walden North IPP's cost of service including a rate of return given the risks borne by the IPP."

Page 34 of the Application states that "The Cayoose Creek Indian Band and the T'it'q'et Administration are two of the eleven communities constituting the St'át'imc Nation."

Pages 35 and 36 of the Application states the following:

> "In 2011, St'át'imc Nation, the Province of British Columbia and BC Hydro entered into a series of settlement agreements that settled all past, present and future impacts and claims relating to BC Hydro's Bridge River facilities, and their continued maintenance and operations…As part of BC Hydro's commitment under the St'át'imc settlement agreements, BC Hydro has been consulting with T'it'q'et Administration about the transfer of lands from BC Hydro to T'it'q'et Administration, related to the transmission line easement and road access easement required for Walden North…"

1.2.1 Please provide an ownership structure, along with percentages, that indicates the Cayoose Creek Indian Band's ownership level in the Walden North Hydro project.

RESPONSE:

The Walden North IPP has provided BC Hydro with the following:

"The Walden North hydroelectric facility was acquired in February 2016 by Cayoose Creek Power Limited Partnership, a limited partnership formed under the laws of the Province of British Columbia.

Cayoose Creek Power Limited Partnership has two limited partners, Cayoose Creek Development Corp. ("CCDC") (49%) and Innergex Renewable Energy Inc. (51%).

CCDC is the business arm of Cayoose Creek Indian Band. All of the shares of CCDC are held in bare trust for the Cayoose Creek Indian Band. For reference, after several years of engagement and discussion T'it'q'et Administration declined ownership and participation in the partnership.

Under the Cayoose Creek Power Limited Partnership Agreement, if the EPA is not renewed, Cayoose Creek Development Corp. (and its shareholder, Cayoose Creek Indian Band) receives zero income. If the EPA is renewed, the income that Cayoose Creek Development Corp. would earn over the life of the proposed 40 year EPA period with respect to the Walden North hydroelectric facility would be determined by the net income (including capital gain) or the net loss (including capital loss) of Cayoose Creek Power Limited Partnership, and by the allocation thereof among the limited partners of record of Cayoose Creek Power Limited Partnership."

2.0 A. BC ENERGY OBJECTIVES CONSIDERATION

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1.2.1.1 Please provide BC Hydro's estimate of the net present value of the income the Cayoose Creek Indian Band would earn over the life of the proposed 40-year EPA period compared to a scenario where the EPA was not renewed. Please provide supporting calculations and describe all key assumptions used.

RESPONSE:

BC Hydro does not have the information to provide the requested calculations. BC Hydro asked the IPP for an answer to this question. For the IPPs response please refer to BC Hydro response to BCUC IR 1.2.1.

2.0 A. BC ENERGY OBJECTIVES CONSIDERATION

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1.2.1.2 Please quantify any additional First Nations benefits (for example, jobs and training). Please include in your response an estimate (if available) of the number of St'át'imc Nation members employed at the Walden North Hydro facility.

RESPONSE:

The Walden North IPP has provided BC Hydro with the following information:

> **"There are First Nations benefits related to contracting, jobs and training under the Limited Partnership Agreement between Cayoose Creek Power Inc., as general partner, and Cayoose Creek Development**

Corporation and Innergex Renewable Energy Inc., as limited partners; the Partnership Agreement is not available for disclosure. The number of St'at'imc Nation members employed at the Walden North hydroelectric facility is not available."

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1.2.2 Please explain how much weight BC Hydro considers should be placed on the Cayoose Creek Indian Band equity ownership/profit sharing arrangement for Walden North Hydro.

RESPONSE:

Relationships with First Nations are important to BC Hydro. The local First Nation community stands to benefit from this EPA renewal through its participation in the project leading to greater economic prosperity for its community.

Please refer to BC Hydro's response to BCUC IR 1.1.3.

2.0 A. BC ENERGY OBJECTIVES CONSIDERATION

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1.2.3 Please explain whether the T'it'q'et Administration, as well as other communities in the St'at'imc Nation, are supportive of the Walden North EPA proposed EPA renewal.

RESPONSE:

Walden North is within the consultative boundaries, per the Government of British Columbia's Consultative Areas Database, of two First Nations: Cayoose Creek Indian Band (Cayoose Creek) and T'it'q'et Administration (T'it'q'et).

T'it'q'et asked BC Hydro a few questions related to the Walden North IPP in October 2017 and BC Hydro answered the questions. T'it'q'et has not expressed

any concerns to BC Hydro about the renewal of the Walden North EPA and BC Hydro is not aware of any general concerns T'it'q'et might have about the renewal of the EPA for Walden North.

Cayoose Creek has informed BC Hydro that they are comfortable with all aspects of the refurbishment, construction, and mitigation plans for Walden North. BC Hydro is also of the view that Cayoose Creek, being part owner of Walden North, is supportive of the renewal of the EPA for Walden North.

3.0 A. BC ENERGY OBJECTIVES CONSIDERATION

Reference: ENVIRONMENTAL IMPACTS – SECHELT CREEK
Exhibit B-1, p. 9, pp. 14–16, p. 22

Page 9 of the Application states that Sechelt Creek Hydro "…has been recognized for its environmental stewardship, including efforts to enhance the salmon run in Sechelt Creek…"

Page 14 of the Application states that "…the Sechelt Creek facility has all material permits needed for continued operation and these permits do not require renewal during the 40-year term of the EPA renewal, with the exception of the following provincial agreements and permits:

- Lease agreements…which expire October 16, 2025;
- Right of way agreement for the penstock, which expires October 1, 2030;
- Licence of occupation…which expires in 2027 (it can be extended to match the term of the EPA); and
- Conversion of the existing permit for the dock and barge ramp to current land tenure standard, which is currently underway with FLNRO."

Pages 15 and 16 of the Application states the following:

The Sechelt Creek IPP has advised:

- They do not anticipate any changes to the physical footprint of the Sechelt Creek facility and there will be no change to the energy output of the facility or operations as a result of the EPA renewal;
- There are no environmental impacts that resulted from the original construction of Sechelt Creek facility that have the potential to worsen with continued operation; and
- It is uncertain whether the Sechelt Creek facility would be decommissioned or decommissioned earlier in the event the EPA is not renewed."

Page 16 of the Application also states that "BC Hydro is…of the view that the renewal of the Sechelt Creek EPA has no potential new or incremental impacts on Aboriginal rights and title…"

1.3.1 Please discuss what risks (financial, operational, etc.), if any, would be associated with each of the above mentioned provincial agreements and permits.

RESPONSE:

Each of the above mentioned provincial agreements and permits, if not renewed or reissued, may introduce financial and/or operational risk to the Sechelt Creek project. Pursuant to the Sechelt Creek EPA, any such risks are essentially borne by the Sechelt Creek IPP. If the Sechelt Creek IPP is not able to operate and deliver energy to BC Hydro, the risk to BC Hydro is that it will not receive the energy it expects to be delivered by the IPP.

The Sechelt Creek IPP has advised BC Hydro that it believes the risk of the above-noted provincial agreements and permits not being renewed or reissued is low given the low-impact nature of the facility, the lack of community opposition, the high level of support from shíshálh Nation, and Sechelt Creek IPP's ability to recently obtain other permits (e.g. a statutory right-of-way for the existing transmission line and a licence of occupation for the powerhouse access road).

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The Sechelt Creek IPP has advised:

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- There are no environmental impacts that resulted from the original construction of Sechelt Creek facility that have the potential to worsen with continued operation; and
- It is uncertain whether the Sechelt Creek facility would be decommissioned or decommissioned earlier in the event the EPA is not renewed."

Page 16 of the Application also states that "BC Hydro is…of the view that the renewal of the Sechelt Creek EPA has no potential new or incremental impacts on Aboriginal rights and title…"

1.3.2 Please discuss what is meant by the statement "Conversion of the existing permit for the dock and barge ramp to current land tenure standard…" Would construction or maintenance be involved? If so, please discuss the environmental impact on the shíshálh Nation, consequent to such construction or maintenance.

RESPONSE:

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

> **This statement refers to a change in the legal documentation of the property use rights granted to the Sechelt Creek IPP for the dock and barge ramp. The original property use rights were provided pursuant to an agreement with a former corporate land owner. This agreement was subsequently assigned to the Crown upon the Crown's acquisition of the land. The Province has requested that the facility apply for provincial land tenure to replace the existing contractual rights.**
>
> **No incremental construction or maintenance is required to convert to provincial land tenure. shíshálh Nation and the Sunshine Coast Regional District have both notified the Province that they do not object to the issuance of this land tenure.**

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- Lease agreements…which expire October 16, 2025;
- Right of way agreement for the penstock, which expires October 1, 2030;
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- They do not anticipate any changes to the physical footprint of the Sechelt Creek facility and there will be no change to the energy output of the facility or operations as a result of the EPA renewal;
- There are no environmental impacts that resulted from the original construction of Sechelt Creek facility that have the potential to worsen with continued operation; and
- It is uncertain whether the Sechelt Creek facility would be decommissioned or decommissioned earlier in the event the EPA is not renewed."

Page 16 of the Application also states that "BC Hydro is…of the view that the renewal of the Sechelt Creek EPA has no potential new or incremental impacts on Aboriginal rights and title…"

1.3.3 Please discuss why the Sechelt Creek facility would be decommissioned or decommissioned earlier in the event the EPA is not renewed.

RESPONSE:

To clarify, the Sechelt Creek IPP advised BC Hydro that they were uncertain whether the Sechelt Creek facility would be decommissioned or decommissioned earlier in the event the EPA is not renewed (as noted above).

Sechelt Creek IPP also advised that:

- **The EPA renewal ensures that the facility will not be decommissioned during the EPA term;**

- **If the EPA were not to be renewed, this could result in facility decommissioning if for example First Nations benefits are reduced, which could in turn result in the withdrawal of First Nations support, thereby increasing the risk of permit non-renewal; and**

- **If the EPA is not renewed, it may be uneconomic to make the necessary capital investments for continued operation.**

Please also refer to BC Hydro's response to BCUC IR 1.36.1.

3.0 A. BC ENERGY OBJECTIVES CONSIDERATION

Reference: ENVIRONMENTAL IMPACTS – SECHELT CREEK
Exhibit B-1, p. 9, pp. 14–16, p. 22

Page 9 of the Application states that Sechelt Creek Hydro "…has been recognized for its environmental stewardship, including efforts to enhance the salmon run in Sechelt Creek…"

Page 14 of the Application states that "…the Sechelt Creek facility has all material permits needed for continued operation and these permits do not require renewal during the 40-year term of the EPA renewal, with the exception of the following provincial agreements and permits:

- Lease agreements…which expire October 16, 2025;
- Right of way agreement for the penstock, which expires October 1, 2030;
- Licence of occupation…which expires in 2027 (it can be extended to match the term of the EPA); and
- Conversion of the existing permit for the dock and barge ramp to current land tenure standard, which is currently underway with FLNRO."

Pages 15 and 16 of the Application states the following:

The Sechelt Creek IPP has advised:

- They do not anticipate any changes to the physical footprint of the Sechelt Creek facility and there will be no change to the energy output of the facility or operations as a result of the EPA renewal;
- There are no environmental impacts that resulted from the original construction of Sechelt Creek facility that have the potential to worsen with continued operation; and
- It is uncertain whether the Sechelt Creek facility would be decommissioned or decommissioned earlier in the event the EPA is not renewed."

Page 16 of the Application also states that "BC Hydro is…of the view that the renewal of the Sechelt Creek EPA has no potential new or incremental impacts on Aboriginal rights and title…"

1.3.3.1 Please discuss any environmental impact that decommissioning would have on the shíshálh Nation and surrounding community.

RESPONSE:

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

- **The ongoing operation of the facility provides for continued benefits from the spawning channel which has helped restore the salmon population previously harmed due to industrial development in the area. The spawning channel cannot be operated independently; it depends on operation of the hydro facility. The ongoing maintenance on the spawning channel is performed by the site operators and shíshálh Nation which includes debris removal, ensuring vegetation is maintained, and providing annual counts of salmon;**

- **The success of the spawning channel is made possible by a low flow augmentation scheme that was constructed at Sechelt Lake, a natural lake in the upper catchment, which is operated and maintained by the Sechelt Creek IPP. It is estimated that 70,000 salmon are dependent on Sechelt Creek's spawning channel. This salmon population would not be supported without the ongoing operation of the Sechelt Creek project;**

- **If the Sechelt Creek facility were to be decommissioned, the environmental benefit achieved from the spawning channel would be lost. In addition to the direct impact on the salmon population, which would likely decline without the spanning channel; there would be an indirect impact on eagles, seals, bears and other wildlife which are dependent on the salmon. A decline in the salmon and wildlife populations could in turn affect commercial fishing (which has returned to Salmon Inlet for the first time in 60 years) and could potentially impact the boost in eco-tourism observed in the area more recently; and**

- **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.**

3.0 A. BC ENERGY OBJECTIVES CONSIDERATION

Reference: ENVIRONMENTAL IMPACTS – SECHELT CREEK
Exhibit B-1, p. 9, pp. 14–16, p. 22

Page 9 of the Application states that Sechelt Creek Hydro "…has been recognized for its environmental stewardship, including efforts to enhance the salmon run in Sechelt Creek…"

Page 14 of the Application states that "…the Sechelt Creek facility has all material permits needed for continued operation and these permits do not require renewal during the 40-year term of the EPA renewal, with the exception of the following provincial agreements and permits:

- Lease agreements…which expire October 16, 2025;
- Right of way agreement for the penstock, which expires October 1, 2030;
- Licence of occupation…which expires in 2027 (it can be extended to match the term of the EPA); and
- Conversion of the existing permit for the dock and barge ramp to current land tenure standard, which is currently underway with FLNRO."

Pages 15 and 16 of the Application states the following:

The Sechelt Creek IPP has advised:

- They do not anticipate any changes to the physical footprint of the Sechelt Creek facility and there will be no change to the energy output of the facility or operations as a result of the EPA renewal;
- There are no environmental impacts that resulted from the original construction of Sechelt Creek facility that have the potential to worsen with continued operation; and
- It is uncertain whether the Sechelt Creek facility would be decommissioned or decommissioned earlier in the event the EPA is not renewed."

Page 16 of the Application also states that "BC Hydro is…of the view that the renewal of the Sechelt Creek EPA has no potential new or incremental impacts on Aboriginal rights and title…"

1.3.4 Please explain whether there would be detrimental impacts on the salmon run if the Sechelt Creek EPA was not renewed, and if yes, whether (and to what extent) BC Hydro could mitigate these impacts.

RESPONSE:

The Sechelt Creek IPP has advised, as provided in BC Hydro's response to BCUC IR 1.3.3 the EPA renewal ensures that the facility will not be decommissioned during the EPA term. Please refer to BC Hydro's response to BCUC IR 1.3.3.1 for a discussion regarding the detrimental impacts on the salmon run if the Sechelt Creek facility were to be decommissioned. 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.

3.0 A. BC ENERGY OBJECTIVES CONSIDERATION

Reference: ENVIRONMENTAL IMPACTS – SECHELT CREEK
Exhibit B-1, p. 9, pp. 14–16, p. 22

Page 9 of the Application states that Sechelt Creek Hydro "…has been recognized for its environmental stewardship, including efforts to enhance the salmon run in Sechelt Creek…"

Page 14 of the Application states that "…the Sechelt Creek facility has all material permits needed for continued operation and these permits do not require renewal during the 40-year term of the EPA renewal, with the exception of the following provincial agreements and permits:

- Lease agreements…which expire October 16, 2025;
- Right of way agreement for the penstock, which expires October 1, 2030;
- Licence of occupation…which expires in 2027 (it can be extended to match the term of the EPA); and
- Conversion of the existing permit for the dock and barge ramp to current land tenure standard, which is currently underway with FLNRO."

Pages 15 and 16 of the Application states the following:

The Sechelt Creek IPP has advised:

- They do not anticipate any changes to the physical footprint of the Sechelt Creek facility and there will be no change to the energy output of the facility or operations as a result of the EPA renewal;
- There are no environmental impacts that resulted from the original construction of Sechelt Creek facility that have the potential to worsen with continued operation; and
- It is uncertain whether the Sechelt Creek facility would be decommissioned or decommissioned earlier in the event the EPA is not renewed."

Page 16 of the Application also states that "BC Hydro is…of the view that the renewal of the Sechelt Creek EPA has no potential new or incremental impacts on Aboriginal rights and title…"

1.3.4.1 Please describe the environmental impacts that resulted from the original construction of the Sechelt Creek facility, and explain whether there would be an overall improvement in these environmental impacts if the Sechelt Creek facility was decommissioned, or decommissioned earlier.

RESPONSE:

BC Hydro has no records in relation to the original construction of the Sechelt Creek facility. The Sechelt Creek IPP has advised BC Hydro of the following:

- **The Sechelt Creek facility was specifically designed, with input from shíshálh Nation, to minimize any negative environmental impacts and has received international recognition for sustainable development;**

- **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; and**

- **Any negative environmental impacts that resulted from the original construction of the facility were minimal and there are no environmental impacts from the original construction of the facility that have the potential to worsen with continued operation of the facility.**

4.0 A. BC ENERGY OBJECTIVES CONSIDERATION

Reference: ENVIRONMENTAL IMPACTS – BROWN LAKE HYDRO
Exhibit B-1, p. 9, pp. 14–16, p. 22

Page 22 of the Application states that "…Brown Lake facility will not be decommissioned or decommissioned earlier if the EPA is not renewed."

1.4.1 Please confirm, or explain otherwise, that as BC Hydro expects the Brown Lake facility will not be decommissioned or decommissioned earlier if the EPA is not renewed, there should be no environmental considerations associated with the EPA renewal.

RESPONSE:

BC Hydro confirms that there are no environmental considerations associated with the Brown Lake EPA renewal. Please see section 5.7(c) and section 5.8 of the Application.

Given that the IPP has indicated that in the absence of the EPA renewal, they will sell electricity to third-parties, BC Hydro has not explored with the IPP whether it has considered that without the Brown Lake EPA renewal there may be environmental considerations associated with its facility.

5.0 A. BC ENERGY OBJECTIVES CONSIDERATION

Reference: ENVIRONMENTAL IMPACTS – WALDEN NORTH HYDRO
Exhibit B-1, pp. 24–25, p. 35; Appendix J-2, p. 2

Pages 24 and 25 of the Application states the following:

> Pursuant to the Diversion Agreement, the Walden North IPP maintains and operates the works that are used to divert water from the Walden North tailrace into BC Hydro's Cayoosh Diversion Tunnel…
>
> …Diversion of Cayoosh Creek water facilitates maintenance of the dilution ratio of Seton River water to Cayoosh Creek water below the Cayoosh confluence which we understand facilitates salmon migration to spawning areas in the Bridge River system, via Seton River and Seton Lake.
>
> …In 2017, BC Hydro commissioned a study to assess the impact of the dilution ration on salmon migration, and it was confirmed that maintaining the dilution ratio facilitates salmon migration during spawning.

Page 35 of the Application states "The Walden North Facility will not be decommissioned or decommissioned earlier if the EPA is not renewed."

1.5.1 Does BC Hydro consider that salmon migration could be negatively affected if the Walden North EPA is not renewed, or that there could be other negative environmental impacts? Please explain.

RESPONSE:

As provided at the end of section 6.2 of the Application, if the Walden North EPA renewal is not accepted, the original EPA and the Forbearance Agreement will remain in effect in accordance with their respective terms. If there is no EPA with BC Hydro, the Diversion Agreement terminates. Without an EPA and Diversion Agreement, there are uncertainties regarding how the parties will manage water flows in relation to the diversion tunnel.

Water needs to be fed from Cayoosh Creek through the IPP's plant (which includes its diversion structure) to reach BC Hydro's Cayoosh Diversion Tunnel. The diversion structure is essentially the Walden North IPP's tailrace structure as shown on page 1 of Appendix G of the Application. This tailrace structure feeds into and connects to BC Hydro's Cayoosh Diversion Tunnel. Pursuant to the Diversion Agreement, the IPP built and maintains its diversion structure connecting to the tunnel. The Cayoosh Diversion Tunnel is owned and operated by BC Hydro and allows for the diversion of water from the Walden North IPP's tailrace to Seton Lake which is part of BC Hydro's Bridge River system.

If the diversion of water from Cayoosh Creek to Seton Lake is discontinued, salmon migration will be negatively affected. BC Hydro has conducted an analysis that showed the tunnel being opened (which allows water from the Cayoosh Creek to flow into Seton Lake) is critical in maintaining the dilution ratios that support salmon migration. 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.

The continuation of the Diversion Agreement enables BC Hydro to avoid the cost of an alternative diversion structure (in order to feed water into BC Hydro's diversion tunnel) if such a structure is required sometime in the future. Given the existing diversion structure is already in place and owned by the IPP, BC Hydro has not carried out an assessment of available options for building an alternative diversion structure at this time. We have also not considered the alternative of negotiating a new diversion agreement in the absence of an EPA and we do not have an estimate of what such an agreement might cost.

5.0 A. BC ENERGY OBJECTIVES CONSIDERATION

Reference: ENVIRONMENTAL IMPACTS – WALDEN NORTH HYDRO
Exhibit B-1, pp. 24–25, p. 35; Appendix J-2, p. 2

Pages 24 and 25 of the Application states the following:

> Pursuant to the Diversion Agreement, the Walden North IPP maintains and operates the works that are used to divert water from the Walden North tailrace into BC Hydro's Cayoosh Diversion Tunnel…
>
> …Diversion of Cayoosh Creek water facilitates maintenance of the dilution ratio of Seton River water to Cayoosh Creek water below the Cayoosh confluence which we understand facilitates salmon migration to spawning areas in the Bridge River system, via Seton River and Seton Lake.
>
> …In 2017, BC Hydro commissioned a study to assess the impact of the dilution ration on salmon migration, and it was confirmed that maintaining the dilution ratio facilitates salmon migration during spawning.

Page 35 of the Application states "The Walden North Facility will not be decommissioned or decommissioned earlier if the EPA is not renewed."

1.5.1 Does BC Hydro consider that salmon migration could be negatively affected if the Walden North EPA is not renewed, or that there could be other negative environmental impacts? Please explain.

1.5.1.1 If yes, please explain whether BC Hydro could mitigate these negative environmental effects (for example, through a separately negotiated diversion agreement). If yes, please estimate the financial cost of mitigation and explain to what extent negative environmental impacts would remain.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.5.1.

6.0 A. BC ENERGY OBJECTIVES CONSIDERATION

Reference: IMPACTS TO ECONOMIC DEVELOPMENT – SECHELT CREEK HYDRO, BROWN LAKE HYDRO, WALDEN NORTH HYDRO CEA, Section 2(l) Exhibit B-1, pp. 16, 23, 35

Section (2)(l) of the CEA states one of BC's energy objectives is "…to foster the development of first nation and rural communities through the use and development of clean or renewable resources;"

1.6.1 Please describe the economic development impact that could result if BC Hydro did not renew the Sechelt Creek facility EPA. Please include an estimate of the number of full-time equivalents (FTE's) employed at the facility and any other ongoing economic considerations (such as loss of water rentals, property taxes).

RESPONSE:

The public version of this response has been redacted to maintain in confidence commercially sensitive information. The redacted information is commercially sensitive to the IPP, and public disclosure of this information would be harmful to the commercial interests of the IPP.

The Sechelt Creek IPP has provided the following:

- **The operation of the facility generates positive economic impacts within the surrounding communities and B.C. through direct expenditures on goods and services, creation of employment opportunities and generation of tax revenues for local, provincial and federal governments;**

- **It is estimated that in 2015 the Sechelt Creek IPP contributed $[redacted] annually to the provincial Gross Domestic Product, $[redacted] in tax revenues (including property taxes), $[redacted] in water rentals, and six local Full-Time Equivalent (FTEs) positions;**

- **Capital expenditures associated with the facility are projected to total $[redacted] in B.C. over five years and are expected to support an additional cumulative eight and a half FTEs of employment, and roughly $[redacted] in provincial GDP and $[redacted] in tax revenues for all levels of government; and**

- **In addition, there are other economic benefits associated with the facility that are more difficult to quantify, such as the benefits provided by the salmon spawning channel, as detailed in BC Hydro's response to BCUC IR 1.3.3.1.**

6.0 A. BC ENERGY OBJECTIVES CONSIDERATION

Reference: IMPACTS TO ECONOMIC DEVELOPMENT – SECHELT CREEK HYDRO, BROWN LAKE HYDRO, WALDEN NORTH HYDRO CEA, Section 2(l) Exhibit B-1, pp. 16, 23, 35

Section (2)(l) of the CEA states one of BC's energy objectives is "…to foster the development of first nation and rural communities through the use and development of clean or renewable resources;"

1.6.1.1 Does BC Hydro consider that, when BC Hydro is no longer in an energy surplus situation, the BC economic development benefits from a new wind farm would be greater, similar or less compared to the economic development benefits associated with the renewal of the Sechelt Creek EPA? Please explain.

RESPONSE:

These EPA renewals are contracts with already constructed facilities, and incremental economic development is generally limited to ongoing maintenance, operation and sustaining investments. In comparison, a new wind farm will have additional employment benefits associated with construction and project development. Once constructed, the economic development in terms of employment would be generally similar between hydro and wind projects of similar scale.

6.0 A. BC ENERGY OBJECTIVES CONSIDERATION

Reference: IMPACTS TO ECONOMIC DEVELOPMENT – SECHELT CREEK HYDRO, BROWN LAKE HYDRO, WALDEN NORTH HYDRO CEA, Section 2(l) Exhibit B-1, pp. 16, 23, 35

Section (2)(l) of the CEA states one of BC's energy objectives is "…to foster the development of first nation and rural communities through the use and development of clean or renewable resources;"

1.6.2 Please confirm or explain otherwise that, as BC Hydro expects the Brown Lake and Walden North facility will not be decommissioned or decommissioned earlier if the EPA is not renewed, there should be no associated economic development considerations. If no, please explain.

RESPONSE:

The public version of this response has been redacted to maintain in confidence commercially sensitive information. The redacted information is commercially sensitive to the IPP, and public disclosure of this information would be harmful to the commercial interests of the IPP.

As stated in the Application, all three EPA renewals provide the Province of B.C., applicable regional districts and local communities with ongoing economic benefits such as water rentals, property taxes, employment opportunities, direct expenditures on goods and services, and other contracting opportunities.

For the Walden North IPP, it is estimated that in 2018, it contributed approximately $[redacted] in property taxes, $[redacted] in water rentals, and [redacted] local Full-Time Equivalent (FTEs) positions. There are also capital expenditures associated with the facility that are projected to total $[redacted] in B.C. for major projects related to the facility, which provides direct job and procurement opportunities; and sub-contracting opportunities in relation to operations and maintenance opportunities translating into job and procurement opportunities.

For the Brown Lake IPP, it is estimated that in 2018, it contributed approximately $[redacted] in property taxes, $[redacted] in water rentals, and [redacted] local FTE position and one part-time position. There are also sub-contracting opportunities in relation to operations and maintenance opportunities translating into job and procurement opportunities.

Given that the opportunity costs for the Brown Lake and Walden North IPPs are less than the respective EPA renewal price, BC Hydro expects that if these two

facilities continue to operate in the absence of the EPA renewals, the economic development benefits to the Province and the local communities will likely be less. BC Hydro is not able to quantify the differences if these EPA renewals are not accepted.

7.0 A. BC ENERGY OBJECTIVES CONSIDERATION

Reference: BC ENERGY OBJECTIVES
Exhibit B-1, pp. 15, 27; Mandate Letter from the Ministry of Energy, Mines and Petroleum Resources to BC Hydro, April 18, 2018[1]
First Nations – General

The Mandate Letter from the Ministry of Energy, Mines and Petroleum Resources to BC Hydro dated April 18, 2018 states on page 2: "Please ensure that going forward your organization incorporates the [United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP)] and the [Calls to Action of the Truth and Reconciliation Commission (TRC)], give the specific mandate and context of your organization."

1.7.1 Please explain, for each EPA included in this Application, whether the UNDRIP or the TRC are relevant to the public interest evaluation of these proposed contracts, and if so how.

RESPONSE:

In the context of the renewal of the Sechelt Creek EPA, Brown Lake EPA and the Walden North EPA, BC Hydro is of the view that the renewals do not give rise to potential incremental adverse impacts on Aboriginal rights and title and that there are no adverse impacts on Aboriginal rights and title relevant to the public interest evaluation.

On this basis BC Hydro's mandate to incorporate UNDRIP and TRC is not part of the public interest evaluation for this Application.

[1] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/openness-accountability/2018-2019-bc-hydro-mandate-letter.pdf

8.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO OPPORTUNITY COST ESTIMATE
Exhibit B-1, pp. 8, 9, 12, 20, 31
Methodology

BC Hydro states on page 9 of the Application that its opportunity cost analysis values IPP energy at the market price during periods of surplus, and at the long run marginal cost (LRMC) during periods of deficit. BC Hydro estimates its marginal resources and related costs in Table 1 of the Application (page 8), which includes an estimated LRMC from F2022 to F2033 of less than $89/MWh, and from F3024 and beyond of $104/MWh.

BC Hydro estimates its opportunity cost (adjusted for project-specific characteristics) for each EPA on page 12, 20 and 31 of the Application.

1.8.1 Please provide the analysis, including all key assumptions, to support BC Hydro's opportunity cost estimate for each EPA.

RESPONSE:

The public version of this response and the attached spreadsheet has been redacted to maintain in confidence commercially sensitive information. The public disclosure of this information would prejudice BC Hydro's negotiating position and commercial interests with respect to other EPA renewals.

Attached is BC Hydro's Excel spreadsheet that provides the calculations and assumptions for BC Hydro's opportunity cost for each of the EPA renewals as provided on pages 12, 20 and 31 of the Application. In addition, in order to provide the numerical support for values provided in other BC Hydro responses in this proceeding, the model also includes the calculations and assumptions for IPP opportunity cost and levelized EPA renewal price.

BC Hydro notes that the following considerations were not reflected, and should have been, in BC Hydro's opportunity costs as set out in the Application, correcting for these results in minor adjustments to BC Hydro's opportunity costs:

- **Losses were excluded for the Brown Lake and Walden North EPA renewals. The energy loss factors for Brown Lake (North Coast) and for Walden North (Kelly Nicola) are 6.4 and 3.7 per cent, respectively;**

- **The present value calculation of the Sechelt Creek EPA renewal energy volumes excluded the volume in the final year of the EPA;**

- **The impact of the Forbearance Agreement for Walden North was not reflected. BC Hydro's opportunity cost for the Walden North EPA renewal as stated in the Application was based on an assumption that without the renewal there is no EPA with BC Hydro. For the Walden North IPP, this is not accurate because the original EPA has not been terminated and will continue in accordance with its terms and the Forbearance Agreement if the EPA renewal is not accepted by the BCUC. If this additional factor is considered, BC Hydro's opportunity cost would be the levelized value of the remaining existing EPA term (assuming the existing EPA is terminated at the earliest termination date specified in the Forbearance Agreement) and the value of the energy to the BC Hydro system over the remainder of the equivalent EPA renewal term; and**

- **Water rentals for Seton (related to the Cayoosh Diversion Tunnel) were not included for the Walden North EPA renewal. For calculating BC Hydro's Opportunity Cost for the Walden North EPA renewal (including the energy from Seton, i.e., $[redacted]/MWh), BC Hydro assumed that without the renewal there is no additional energy at Seton (through the Cayoosh Diversion Tunnel) and that the replacement energy would need to be acquired through other means. If this Seton energy were also required to be replaced, BC Hydro's opportunity cost would be the cost of alternatives, less the cost of water rentals that BC Hydro would be avoiding, by not generating the additional energy at Seton (24.4 GWh per year in each year that the Forbearance Agreement is not in effect).**

For completeness, the BC Hydro opportunity costs estimates are shown in the table below based on what was provided in the Application and reflecting the revisions noted above. Also for completeness, we have included a calculation of opportunity costs using the market energy price for the full term of the EPAs. Please refer to BC Hydro's response to BCUC IR 1.8.4. BC Hydro notes that the market price assumption used below represents the mid-forecast (B.C. Border sell price in all years) based on the ABB spring 2016 reference case, and that there is significant uncertainty in the forecast as indicated in figure 1 of BC Hydro's response to CEC IR 1.4.3. A summary of the model results and input assumptions are provided in the 'Summary' tab of the attached Excel spreadsheet. The supporting calculations are provided in the 'Annual Model' and 'Monthly Model' tabs of the attached Excel spreadsheet[1]

[1] BC Hydro notes that there is no supporting calculation for the $[redacted]/MWh BC Hydro Opportunity Cost for the Sechelt Creek Hydro EPA renewal provided in the Application (equivalent to scenario "2" on the 'Summary' worksheet – see cell B8). This calculation can be reproduced by changing the NPV formula in cell B9 of the 'Annual Model' worksheet to reference the range "D9:AQ9" rather than "D9:AR9".

Table 1 BC Hydro's Opportunity Cost (2017$/MWh)

EPA (Application Reference)	Application	Revised	Market
Sechelt Creek Hydro (Page 12, Table 3)	[redacted]	[redacted]	[redacted]
Brown Lake Hydro (Page 20, Table 5)	[redacted]	[redacted]	[redacted]
Walden North Hydro (Page 31, Table 7)	[redacted]	[redacted]	[redacted]

[2] The Brown Lake hydro facility is estimated to provide 6 MW of dependable capacity. Reflecting the long-term value of this capacity would increase BC Hydro's opportunity costs by approximately $[redacted]-$[redacted]/MWh.

CONFIDENTIAL ATTACHMENT

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8.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO OPPORTUNITY COST ESTIMATE
Exhibit B-1, pp. 8, 9, 12, 20, 31
Methodology

BC Hydro states on page 9 of the Application that its opportunity cost analysis values IPP energy at the market price during periods of surplus, and at the long run marginal cost (LRMC) during periods of deficit. BC Hydro estimates its marginal resources and related costs in Table 1 of the Application (page 8), which includes an estimated LRMC from F2022 to F2033 of less than $89/MWh, and from F3024 and beyond of $104/MWh.

BC Hydro estimates its opportunity cost (adjusted for project-specific characteristics) for each EPA on page 12, 20 and 31 of the Application.

1.8.2 For the purpose of valuing IPP energy during F2022 to F2033, has BC Hydro assumed it will be in an energy surplus or deficit position? Please provide the analysis (i.e. load resource balance) to support this position.

RESPONSE:

At the time of the negotiating and executing the EPA renewals, BC Hydro had assumed it would have an energy shortfall (prior to future planned resources) beginning in fiscal 2022 based on the planning view of the LRB shown on line 12 of Table 3-6 of Appendix B to the Application. Please also refer to BC Hydro's response to BCUC IR 1.11.2.2.1.

8.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO OPPORTUNITY COST ESTIMATE
Exhibit B-1, pp. 8, 9, 12, 20, 31
Methodology

BC Hydro states on page 9 of the Application that its opportunity cost analysis values IPP energy at the market price during periods of surplus, and at the long run marginal cost (LRMC) during periods of deficit. BC Hydro estimates its marginal resources and related costs in Table 1 of the Application (page 8), which includes an estimated LRMC from F2022 to F2033 of less than $89/MWh, and from F3024 and beyond of $104/MWh.

BC Hydro estimates its opportunity cost (adjusted for project-specific characteristics) for each EPA on page 12, 20 and 31 of the Application.

1.8.2.1 Does BC Hydro consider that acceptance of EPAs in this Application will, over the F2022 to F2033 period, result in both (i) lower demand side management (DSM) expenditures, and (ii) reduced renewal volumes from other IPPs (compared to an option where they are not accepted)? Please explain.

RESPONSE:

Acceptance of EPAs in this Application may, but will not necessarily, result in reduced DSM expenditures and reduced future EPA renewals over the fiscal 2022 to fiscal 2033 period than shown in the F12-F19 RRA LRB (Table 3-8 and Table 3-9 of Appendix B to the Application). For example, since our May 31, 2018 filing, three EPAs (McDonald Ranch, Seaton Creek Hydro and Morehead Creek Hydro) have expired and have not been renewed; however, these three EPAs were included in the forecast for the purpose of this Application because the decision to not renew was made after the forecast was finalized.

As noted in BC Hydro's response to BCUC IR 1.8.4, BC Hydro recently adopted the use of market price as a conservative interim assumption for evaluating energy during surplus and deficit periods. This approach is consistent with BC Hydro's plan to stay within the cost forecast that aligns with the rates set out in the Government of B.C.'s Comprehensive Review, including expenditures for DSM and EPA renewals. In addition, the next IRP will inform our future plans for the level of DSM expenditures and volume of EPA renewals.

8.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO OPPORTUNITY COST ESTIMATE
Exhibit B-1, pp. 8, 9, 12, 20, 31
Methodology

BC Hydro states on page 9 of the Application that its opportunity cost analysis values IPP energy at the market price during periods of surplus, and at the long run marginal cost (LRMC) during periods of deficit. BC Hydro estimates its marginal resources and related costs in Table 1 of the Application (page 8), which includes an estimated LRMC from F2022 to F2033 of less than $89/MWh, and from F3024 and beyond of $104/MWh.

BC Hydro estimates its opportunity cost (adjusted for project-specific characteristics) for each EPA on page 12, 20 and 31 of the Application.

1.8.3 Please explain how BC Hydro has used a 'less than' $89/MWh marginal cost estimate for F2022 to F2033 in its opportunity cost analysis of the EPAs. Specifically, did BC Hydro assume a value of $89/MWh or a lower number (and if a lower number, which one)?

RESPONSE:

Given the third column in Table 1 of the Application is showing LRMC, the words "less than" should not have been included. BC Hydro utilized a value of $89/MWh as the marginal cost estimate for fiscal 2022 to fiscal 2033 in calculating BC Hydro's opportunity cost. As noted in the Application BC Hydro's opportunity costs is a cost effectiveness benchmark and is not used to determine the EPA renewal price.

8.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO OPPORTUNITY COST ESTIMATE
Exhibit B-1, pp. 8, 9, 12, 20, 31
Methodology

BC Hydro states on page 9 of the Application that its opportunity cost analysis values IPP energy at the market price during periods of surplus, and at the long run marginal cost (LRMC) during periods of deficit. BC Hydro estimates its marginal resources and related costs in Table 1 of the Application (page 8), which includes an estimated LRMC from F2022 to F2033 of less than $89/MWh, and from F3024 and beyond of $104/MWh.

BC Hydro estimates its opportunity cost (adjusted for project-specific characteristics) for each EPA on page 12, 20 and 31 of the Application.

1.8.3.1 Please explain whether it is standard utility practice to use an estimated renewal price for EPAs in an evaluation of EPA renewals (and if yes, what the estimated EPA renewal price was based on).

RESPONSE:

BC Hydro is not aware of a standard utility practice that uses an estimated renewal price for evaluating EPA renewals.

8.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO OPPORTUNITY COST ESTIMATE
Exhibit B-1, pp. 8, 9, 12, 20, 31
Methodology

BC Hydro states on page 9 of the Application that its opportunity cost analysis values IPP energy at the market price during periods of surplus, and at the long run marginal cost (LRMC) during periods of deficit. BC Hydro estimates its marginal resources and related costs in Table 1 of the Application (page 8), which includes an estimated LRMC from F2022 to F2033 of less than $89/MWh, and from F3024 and beyond of $104/MWh.

BC Hydro estimates its opportunity cost (adjusted for project-specific characteristics) for each EPA on page 12, 20 and 31 of the Application.

1.8.3.2 Please explain whether BC Hydro plans to acquire cost-effective DSM up to $89/MWh from F2022 to F2033 and if not, whether that is reflected in BC Hydro's marginal cost estimate used to evaluate the EPAs in this Application.

RESPONSE:

BC Hydro's current DSM Plan does not acquire all DSM up to $89/MWh. BC Hydro's current DSM Plan is set out in the F20-F21 RRA Application. Future levels of DSM beyond fiscal 2021 are expected to be informed by BC Hydro's next IRP.

BC Hydro's opportunity cost in the Application used the $89/MWh, set out in Table 1 of the Application, to value energy for period between fiscal 2022 to fiscal 2033. Please also refer to BC Hydro's response to CEC IR 1.4.5.

8.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO OPPORTUNITY COST ESTIMATE
Exhibit B-1, pp. 8, 9, 12, 20, 31
Methodology

BC Hydro states on page 9 of the Application that its opportunity cost analysis values IPP energy at the market price during periods of surplus, and at the long run marginal cost (LRMC) during periods of deficit. BC Hydro estimates its marginal resources and related costs in Table 1 of the Application (page 8), which includes an estimated LRMC from F2022 to F2033 of less than $89/MWh, and from F3024 and beyond of $104/MWh.

BC Hydro estimates its opportunity cost (adjusted for project-specific characteristics) for each EPA on page 12, 20 and 31 of the Application.

1.8.4 Please provide analysis to support BC Hydro's estimate of the cost of greenfield IPPs of $104/MWh in F2034. Please provide the date that costs included in this estimate were last updated.

RESPONSE:

The LRMC of $89/MWh (applicable from fiscal 2022 to fiscal 2033) and the LRMC of $104/MWh (applicable for fiscal 2034 and beyond), as used in the Application, were estimated in 2015. The $89/MWh estimate is based on DSM and EPA renewal as the marginal resources and the $104/MWh estimate is based on greenfield wind energy from IPPs.

The $89/MWh estimate was a price signal to set the upper limit on DSM and EPA renewal acquisitions.

The $104/MWh cost estimate was based on the cost of wind energy at the point of interconnection ($84/MWh) plus adjusters such as BC Hydro's cost to integrate and deliver this energy to its load center (the Lower Mainland). The cost of wind energy has continued to decline since these assessments were completed.

These LRMCs are now considered out of date.

BC Hydro's LRB shows it will not need to acquire new energy resources for many years to come. Given potential policy changes that may affect BC Hydro arising from ongoing government review and other energy related policies, on top of technology cost uncertainty in the long term, BC Hydro recently adopted the use of market price as a conservative interim assumption for evaluating energy during surplus and deficit periods.

9.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO OPPORTUNITY COST ESTIMATE
Exhibit B-1, pp. 4, 12, 20, 31, Appendix C; Tacoma Power Integrated Resource Plan (IRP) 2017 update, p. 38[1]; BC Hydro F2017 to F2019 Revenue Requirements Application (RRA) Decision and Order G-47-18, p. 28
2013 IRP

BC Hydro states on page 4 of the Application that it is guided by the 2013 Integrated Resource Plan (IRP) EPA renewal assumptions, and includes experts from the 2013 IRP in Appendix C.

Tacoma Power states on page 38 of its 2017 IRP update, "With wholesale power prices continuing to fall, power from the CBH [Columbia Basin Hydro] contracts now costs more than the price for which it can be sold into the market. Assessing the value of these contracts - whether renewed under current contract terms or negotiated new terms - will be a major component of the 2019 IRP."

Page 28 of the BC Hydro F2017 to F2019 RRA Decision and Order G-47-18 states:

The Panel also recommends a review of the appropriateness of five years between refreshes of the IRP. Five years can be a long time - prices for clean energy have dropped significantly during the five years since the previous IPP review and also BC Hydro's demand has also fallen short of the previously forecasts.

1.9.1 Please explain when BC Hydro expects to finalize its next IRP, and describe the consultation process being undertaken in its preparation.

RESPONSE:

BC Hydro expects to finalize its next IRP by February 28, 2021. This is the prescribed IRP submission date according to the BC Hydro IRP Regulation (B.C. Reg. 266/2018) issued by the B.C. Government for the purposes under the *Clean Energy Act*.

The scope (including the consultation process) of the next IRP has not been determined at this time and will be informed by Phase 2 of the Government Review of BC Hydro.

[1] https://www.mytpu.org/file_viewer.aspx?id=64787

9.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO OPPORTUNITY COST ESTIMATE
Exhibit B-1, pp. 4, 12, 20, 31, Appendix C; Tacoma Power Integrated Resource Plan (IRP) 2017 update, p. 38[1]; BC Hydro F2017 to F2019 Revenue Requirements Application (RRA) Decision and Order G-47-18, p. 28
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BC Hydro states on page 4 of the Application that it is guided by the 2013 Integrated Resource Plan (IRP) EPA renewal assumptions, and includes experts from the 2013 IRP in Appendix C.

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Page 28 of the BC Hydro F2017 to F2019 RRA Decision and Order G-47-18 states:

The Panel also recommends a review of the appropriateness of five years between refreshes of the IRP. Five years can be a long time - prices for clean energy have dropped significantly during the five years since the previous IPP review and also BC Hydro's demand has also fallen short of the previously forecasts.

1.9.2 Please describe at a high level any significant changes that have occurred since the 2013 IRP that could materially affect BC Hydro's IPP renewal strategy (for example, related to load forecast, market price estimates, wind cost estimates).

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.42.1.1 for a discussion of BC Hydro's approach to EPA renewals. This approach has been recently informed by Phase 1 of the Comprehensive Review by Government which provides for 1) indefinite suspension of the Standing Offer Program and 2) the Biomass Energy Program.

[1] https://www.mytpu.org/file_viewer.aspx?id=64787

The examples referenced in the question above (e.g., load forecast, market price forecast and wind cost estimates) do not affect BC hydro's approach to EPA renewals. They are parameters used to determine whether an individual EPA renewal price is cost effective and therefore can affect the ultimate volume of EPAs renewed.

9.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO OPPORTUNITY COST ESTIMATE
Exhibit B-1, pp. 4, 12, 20, 31, Appendix C; Tacoma Power Integrated Resource Plan (IRP) 2017 update, p. 38[1]; BC Hydro F2017 to F2019 Revenue Requirements Application (RRA) Decision and Order G-47-18, p. 28
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Page 28 of the BC Hydro F2017 to F2019 RRA Decision and Order G-47-18 states:

The Panel also recommends a review of the appropriateness of five years between refreshes of the IRP. Five years can be a long time - prices for clean energy have dropped significantly during the five years since the previous IPP review and also BC Hydro's demand has also fallen short of the previously forecasts.

1.9.2.1 Please explain why BC Hydro is seeking acceptance of 40 year renewal contracts now, instead of waiting until guidance is received from the next IRP.

RESPONSE:

The contract term for an EPA is dependent on the particular circumstances of each situation. For the renewals which are the subject of this Application, longer-term renewal contracts were attractive to BC Hydro, at the time that these agreements were negotiated and executed, because this allowed the agreements to extend well past the point at which we had expected to have an energy deficit, during which time BC Hydro valued energy at the cost of other clean, renewable alternatives. Based on a review of third-party condition assessments and capital

[1] https://www.mytpu.org/file_viewer.aspx?id=64787

plans submitted by the IPPs, BC Hydro determined that 40-year renewal terms were appropriate and cost-effective for these particular projects.

Please also refer to BC Hydro's response to BCUC IR 1.42.1.1 for a discussion of what BC Hydro's approach has been with respect to EPA renewals.

10.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, pp. 3, 12, 20, 31, Appendix B, Table 3-8, p. 6, Table 3-9, p. 7; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, pp. 77-82, Exhibit A-24-2-1, Appendix-C Commission Illustrative Alternative Portfolio, Exhibit F1-1, Appendix K, pp. 7, 8
Load Forecast

BC Hydro states on page 3 of the Application that based on the mid-level load forecast in the F2017-F2019 Revenue Requirement Application (RRA), the load resource balance (LRB) identifies a need for new resources in fiscal 2022. BC Hydro includes the F2017-F2019 RRA LRB after planned resources in Appendix B to the Application (Table 3-8 and 3-9).

On page 77 of the British Columbia Utilities Commission (BCUC) 2017 Site C Final Report BCUC found that overall BC Hydro's mid load forecast was excessively optimistic and considered it more appropriate to use the low load forecast. On pages 78 to 82 the BCUC discussed the following issues and factors: recent developments in the industrial sectors; accuracy of historical load forecasts; GDP and other forecast drivers; price elasticity; future rate increases; potential disrupting trends; and flattening electricity demand.

1.10.1 When did BC Hydro last undertake a comprehensive update of its load forecast, and when is the next update expected?

RESPONSE:

BC Hydro last undertook a comprehensive update of its load forecast in October 2018 to support the BC Hydro F20-F21 RRA. However, this forecast only covers fiscal 2019 to fiscal 2024. A new long term load forecast is expected to be completed in Spring 2019. In the interim, we adjusted the May 2016 forecast, which was used in the F17-F19 RRA, by incorporating assumptions consistent with the approach used in the October 2018 Load Forecast. Please refer to BC Hydro's response to BCUC IR 1.11.2.2.1.

10.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, pp. 3, 12, 20, 31, Appendix B, Table 3-8, p. 6, Table 3-9, p. 7; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, pp. 77-82, Exhibit A-24-2-1, Appendix-C Commission Illustrative Alternative Portfolio, Exhibit F1-1, Appendix K, pp. 7, 8
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1.10.2 Please identify and explain whether factors identified by the BCUC in the Site C Inquiry Final Report (pages 78 to 82) have been adjusted in the load forecast assumed in this. Where no adjustment has been made, please explain why not.

RESPONSE:

No, at the time of filing this Application we had not updated our long-term forecast to include the factors cited in the reference above. Please refer to BC Hydro's response to BCUC IR 1.11.2.2.1 for a discussion of BC Hydro's updated LRB.

10.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, pp. 3, 12, 20, 31, Appendix B, Table 3-8, p. 6, Table 3-9, p. 7; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, pp. 77-82, Exhibit A-24-2-1, Appendix-C Commission Illustrative Alternative Portfolio, Exhibit F1-1, Appendix K, pp. 7, 8
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1.10.3 Until BC Hydro has an updated IRP, please discuss the advantages and disadvantages of using BC Hydro's F2017–F2019 RRA mid load forecast vs. the low-load forecast for the purpose of evaluating new energy purchases (for example, through IPP renewals or the Standing Offer Program (SOP)) over the F2018 to F2036 period. Please include a discussion of the risks involved in each approach and how those risks could be mitigated.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.8.4 with respect to BC Hydro's recently adopted conservative interim assumption for evaluating energy during surplus and deficit periods.

BC Hydro also notes that our approach has been recently informed by Phase 1 of the Comprehensive Review by Government which provides, for example, for the indefinite suspension of the SOP.

10.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, pp. 3, 12, 20, 31, Appendix B, Table 3-8, p. 6, Table 3-9, p. 7; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, pp. 77-82, Exhibit A-24-2-1, Appendix-C Commission Illustrative Alternative Portfolio, Exhibit F1-1, Appendix K, pp. 7, 8
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On page 77 of the British Columbia Utilities Commission (BCUC) 2017 Site C Final Report BCUC found that overall BC Hydro's mid load forecast was excessively optimistic and considered it more appropriate to use the low load forecast. On pages 78 to 82 the BCUC discussed the following issues and factors: recent developments in the industrial sectors; accuracy of historical load forecasts; GDP and other forecast drivers; price elasticity; future rate increases; potential disrupting trends; and flattening electricity demand.

1.10.4 For each of BC Hydro's load forecast scenarios (high, mid, low), please provide an Excel file and an accompanying graph that shows the energy load forecasts after DSM (i.e. lines 'e + f' on Table 3-8 of the F2017-F2019 RRA), covering a period from F2018 to F2036:

- as presented by BC Hydro in the Site C Inquiry (Table K-3 in Appendix K to Exhibit F1-1);
- as presented by BC Hydro in the F2017-F2019 Revenue Requirement Application (Table 3-8); and
- as updated by BC Hydro (if available).

RESPONSE:

The attached Excel spreadsheet shows the three (low, mid and high) load forecast after DSM scenarios from the Site C Inquiry, the F17-F19 RRA and a recently updated LRB as described in BC Hydro's response to BCUC IR 1.11.2.2.1. Graphs of the energy and capacity load forecasts after DSM are also provided in BC Hydro's response to BCUC IR 1.11.2.2.1. Please note that in those graphs, the load forecast from the Site C Inquiry is the same as the load forecast from the F17-F19 RRA.

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10.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, pp. 3, 12, 20, 31, Appendix B, Table 3-8, p. 6, Table 3-9, p. 7; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, pp. 77-82, Exhibit A-24-2-1, Appendix-C Commission Illustrative Alternative Portfolio, Exhibit F1-1, Appendix K, pp. 7, 8
Load Forecast

BC Hydro states on page 3 of the Application that based on the mid-level load forecast in the F2017-F2019 Revenue Requirement Application (RRA), the load resource balance (LRB) identifies a need for new resources in fiscal 2022. BC Hydro includes the F2017-F2019 RRA LRB after planned resources in Appendix B to the Application (Table 3-8 and 3-9).

On page 77 of the British Columbia Utilities Commission (BCUC) 2017 Site C Final Report BCUC found that overall BC Hydro's mid load forecast was excessively optimistic and considered it more appropriate to use the low load forecast. On pages 78 to 82 the BCUC discussed the following issues and factors: recent developments in the industrial sectors; accuracy of historical load forecasts; GDP and other forecast drivers; price elasticity; future rate increases; potential disrupting trends; and flattening electricity demand.

1.10.4.1 Please also provide the same information (in an Excel file and graphically) for the peak capacity LRB (i.e, lines 'g + h' on Table 3-9 of the F17-F19 RRA).

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.11.2.2.1.

10.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, pp. 3, 12, 20, 31, Appendix B, Table 3-8, p. 6, Table 3-9, p. 7; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, pp. 77-82, Exhibit A-24-2-1, Appendix-C Commission Illustrative Alternative Portfolio, Exhibit F1-1, Appendix K, pp. 7, 8
Load Forecast

BC Hydro states on page 3 of the Application that based on the mid-level load forecast in the F2017-F2019 Revenue Requirement Application (RRA), the load resource balance (LRB) identifies a need for new resources in fiscal 2022. BC Hydro includes the F2017-F2019 RRA LRB after planned resources in Appendix B to the Application (Table 3-8 and 3-9).

On page 77 of the British Columbia Utilities Commission (BCUC) 2017 Site C Final Report BCUC found that overall BC Hydro's mid load forecast was excessively optimistic and considered it more appropriate to use the low load forecast. On pages 78 to 82 the BCUC discussed the following issues and factors: recent developments in the industrial sectors; accuracy of historical load forecasts; GDP and other forecast drivers; price elasticity; future rate increases; potential disrupting trends; and flattening electricity demand.

1.10.5 Please provide an Excel file and accompanying graph that shows BC Hydro's actual weather normalized load forecast results (energy and peak capacity) for the most recent 10 years and most recent mid load forecast out to F2036. Please discuss any change in trend over time.

RESPONSE:

The figures below show the most recent temperature normalized actuals (total integrated system energy and peak demand) and the adjusted May 2016 mid forecasts as described in BC Hydro's response to BCUC IR 1.11.2.2.1.

The forecast in the figures below start in fiscal 2016 because the foundation for the forecast in BC Hydro's response to BCUC IR 1.11.2.2.1 is the May 2016 Load Forecast, where the forecast reflects our models that were estimated with actual loads up to fiscal 2015.

For the 10- year period from fiscal 2005 to fiscal 2015 average actual compound annual growth on a temperature normalized basis was 0.1 per cent and 0.2 per cent for energy and peak demand, respectively. For the recent three year

period fiscal 2015 to fiscal 2018 the average actual compound annual growth on a temperature normalized basis is 0.4 per cent and 0.0 per cent for energy and peak demand respectively.

For a comparable 10 year forecast period (fiscal 2015 to fiscal 2025) the average annual compound growth is expected to be 1.1 per cent for both energy and peak demand based on the adjusted May 2016 load forecast. Our recent October 2018 energy load forecast (see BC Hydro's response to BCUC IR 1.11.2.2.1) anticipates an average compound annual growth rate of 0.4 per cent between fiscal 2018 and fiscal 2023 and 0.7 between fiscal 2018 and fiscal 2024.

The change in trends between historical and forecast are largely attributed to the factors highlight below:

The fiscal 2005 to fiscal 2015 period:

- **Includes a significant global recession in 2007 to 2008 and a slower than expected economic recovery following; and**

- **This period also included large discrete customer facility closures, primarily in the forestry sector. These load reductions offset growth in other sectors, which explains why historical system growth has been low.**

The fiscal 2015 to fiscal 2018 period:

- **Load growth has been tracking close to forecast (as measured against the May 2016 Load Forecast). This includes growth in each major customer groups driven by provincial economic growth (GDP, housing starts, retail sales); as well as growth in the oil and gas sector, which was partially offset by a paper line closure in the forestry sector.**

The fiscal 2019 to fiscal 2024 period and beyond:

- **Our October 2018 Load Forecast projects continued growth albeit at a lower rate relative to previous forecasts. This is due to a number of factors including lower economic growth forecasts, weaker relationships between economic growth drivers and electricity demand, and higher end-use efficiency projections. This slower growth rate in existing sectors is partially-offset by growth in new and emerging sectors including electric vehicles, cannabis and cryptocurrency. The next five years is also expected to experience continued growth in the natural gas sector, driven by new incremental natural gas processor loads. Several of these projects are currently energized or in the initial stages of connection. This growth will be partially offset by continued expected declines in the forestry sector; and**

- **Looking beyond fiscal 2024, we expect the trend of oil and gas sector growth and forestry sector decline to continue. However, this period will also reflect the emergence of an LNG industry, largely due to LNG Canada's decision to proceed with its terminal in Kitimat, B.C. In addition, the forecast anticipates more growth in electric vehicle load.**

Figure 1 Mid Total Integrated Gross System Energy Requirements Normalized Actuals and Forecast (GWh)

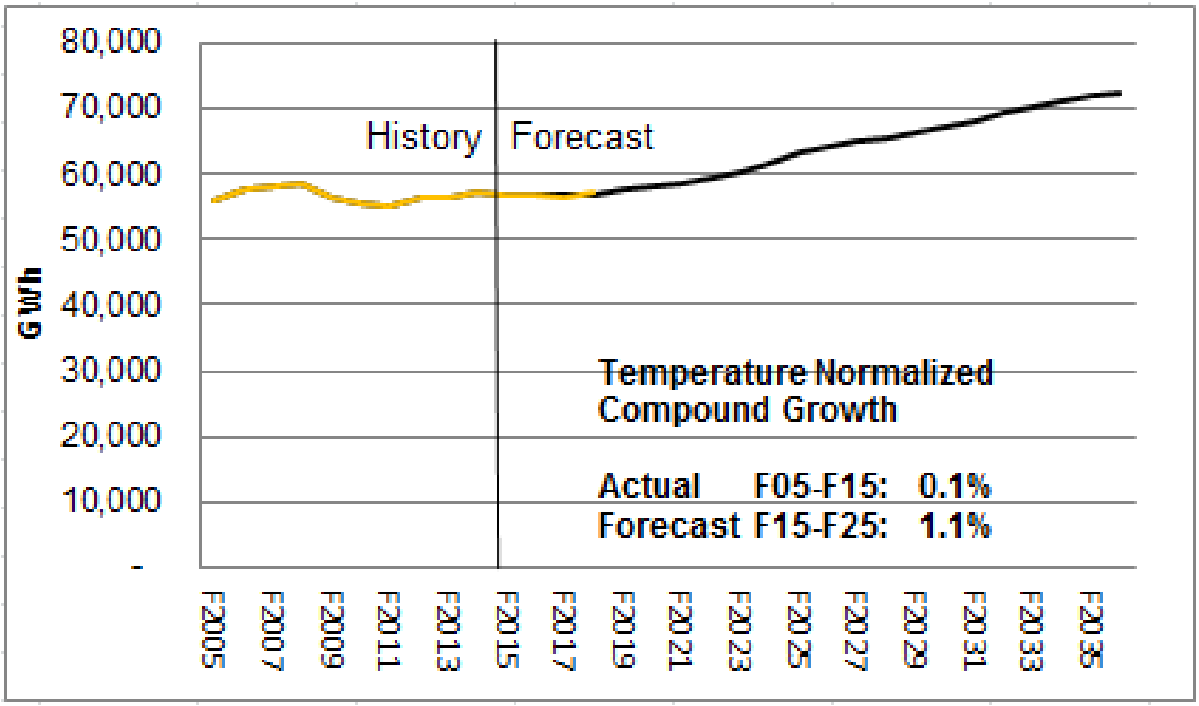
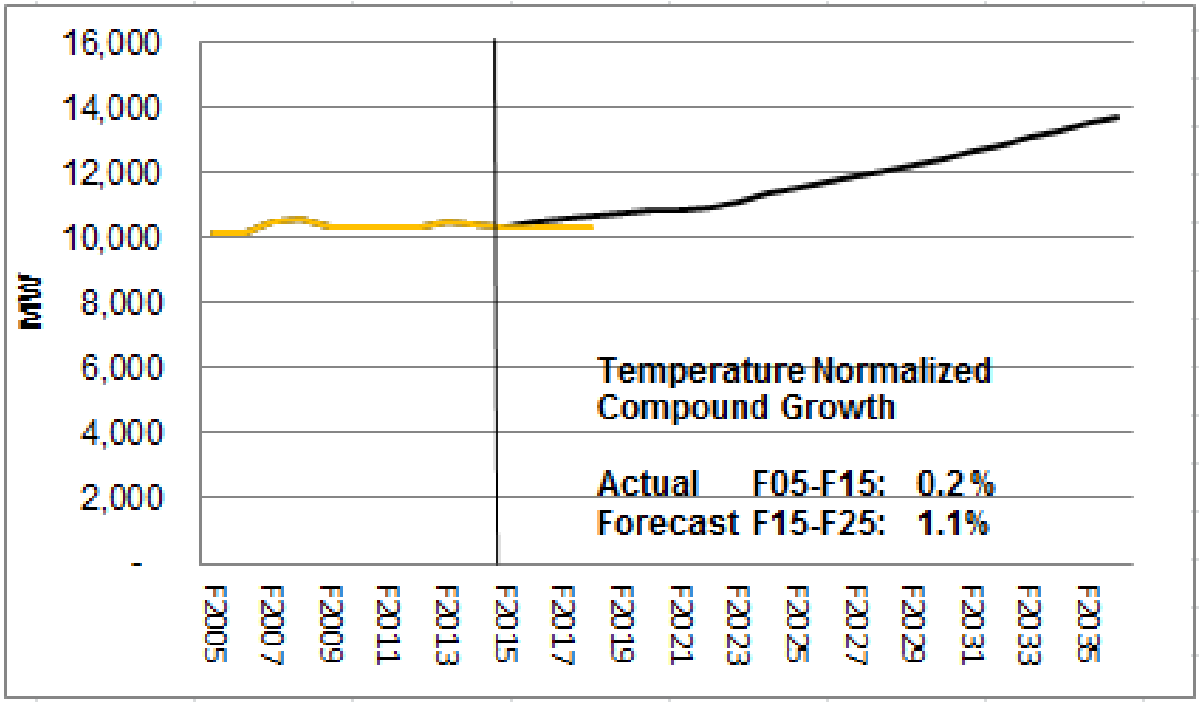


Figure 2 **Mid Total Integrated System Peak Demand Normalized Actuals and Forecast (MW)**



The data used in the above figures is attached to this response.

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Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

11.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, p. 3; 2017 BCUC Site C Inquiry, Exhibit F1-1, pp. 7, 8, Exhibit A-24-2-1, Commission Illustrative Alternative Portfolio
Need for new resources

BC Hydro states on page 3 of the Application that based on the mid-level load forecast in the F2017-F2019 RRA, the LRB identifies a need for new resources in F2022.

1.11.1 Please explain (including supporting analysis and assumptions) how BC Hydro arrived at the F2022 date for the need for new resources.

RESPONSE:

BC Hydro used the planning view of LRBs for the mid load forecast and before planned resources to determine the need for new resources in fiscal 2022 (line 12 of Table 3-6 in Appendix B of the Application). Please refer to BC Hydro response to BCUC IR 1.11.2.2.1 for a description of analysis and assumptions underpinning the LRB used in this Application, as well as an updated LRB.

11.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, p. 3; 2017 BCUC Site C Inquiry, Exhibit F1-1, pp. 7, 8, Exhibit A-24-2-1, Commission Illustrative Alternative Portfolio
Need for new resources

BC Hydro states on page 3 of the Application that based on the mid-level load forecast in the F2017-F2019 RRA, the LRB identifies a need for new resources in F2022.

1.11.2 In a working Excel file, please provide Table K-3 and K-4 in Appendix K to Exhibit F1-1 of the BCUC 2017 Site C Inquiry (Site C LRB).

RESPONSE:

The requested Excel file is attached. However, we note that Table K-3 and Table K-4 do not provide the appropriate view to determine the need for resources. Please refer to BC Hydro's response to BCUC IR 1.11.2.2.1 for 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.

BC Hydro
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REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

11.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, p. 3; 2017 BCUC Site C Inquiry, Exhibit F1-1, pp. 7, 8, Exhibit A-24-2-1, Commission Illustrative Alternative Portfolio
Need for new resources

BC Hydro states on page 3 of the Application that based on the mid-level load forecast in the F2017-F2019 RRA, the LRB identifies a need for new resources in F2022.

1.11.2.1 Please identify and explain any differences between Tables K-3 and K-4 above and Tables 3-8 and 3-9 from the F2017 to F2019 RRA included in Appendix B to the Application.

RESPONSE:

The LRBs filed with the Site C Inquiry, the F17-F19 RRA, and the Waneta 2017 Transaction, are based on the same vintage of demand and supply information. There were certain updates made to the F17-F19 RRA LRBs in the Site C Inquiry and then subsequently in the Waneta 2017 Transaction but the differences are not material and do not impact the first year of energy shortfall (fiscal 2022) in the LRB in the Application. For an explanation of the differences between the LRB in the F17-F19 RRA and the Site C Inquiry, please refer to BCUC supplemental IR 2.21.1 Attachment 2 in the Site C Inquiry. For the differences in LRBs between the Site C Inquiry and the Waneta 2017 Business case, please refer to the attached BC Hydro response to BCUC IR 1.3.1 in the Waneta 2017 Transaction proceeding.

British Columbia Utilities Commission Information Request No. **1.3.1** Dated: **December 8, 2017** British Columbia Hydro & Power Authority Response issued **January 26, 2018**	Page 1 of 2
British Columbia Hydro & Power Authority **Waneta 2017 Transaction**	**Exhibit:** **B-8**

3.0 Topic: Risks and potential value of the Transaction

Reference: Load resource balance – with Waneta
Exhibit B-1, Appendix O; Business Case, pp. 18, 38; Appendix A, pp. 1–2

On page 18 of the Business Case, BC Hydro provides a graph showing its Planning LRB with and without 2/3 Interest Generation. On page 38 of the Business Case BC Hydro explains: "the 2/3 Interest's generation and Teck load are both large, the long term disposition of this generation and load can have impacts on BC Hydro's long term Load Resource Balance."

1.3.1 Please confirm, otherwise explain, that the load resource balances used in the Waneta Business Case analyses include all corrections submitted in the Site C Inquiry proceeding. If not, please identify the differences and comment on their materiality to the Waneta Business Case.

RESPONSE:

Not confirmed. There are small differences between BC Hydro's LRBs used in the Waneta 2017 Business Case and the Site C Inquiry, but these differences are not material.

With respect to energy, the only difference in values between the Waneta 2017 Business Case and the Site C Inquiry occur in the final year of the LRB (fiscal 2036) and amount to 185 GWh for all three load scenarios. This difference is small relative to the need of over 3,700 GWh in fiscal 2036 for the mid scenario and small compared to the energy provided by Waneta.

With respect to capacity, there is no difference for the mid scenario and only slight differences (less than 66 MW) in the last two years of the LRB (fiscal 2035 and fiscal 2036) for the small and large gap.

As a result, these differences do not change the first year of energy or capacity shortfall (fiscal 2034 and fiscal 2029, respectively) in the LRB.

Please refer to BC Hydro's supplemental response to the BCUC Site C IR 2.21.1 for further explanation of the differences in LRB between the Waneta 2017 Business Case and the Site C Inquiry:

http://www.sitecinquiry.com/wp-content/uploads/2017/10/00717_F1-20_BCHydro_SiteC_Submissions.pdf

http://www.sitecinquiry.com/wp-content/uploads/2017/10/00718_F1-20-1_BC-Hydro_Excel-Spreadsheet.xlsx

Since the differences in LRBs between the Waneta 2017 Business Case and the Site C Inquiry are not material, and in order to stay consistent with the LRB used in the modelling for the Waneta 2017 Business Case, all of BC Hydro responses to IRs are based on the LRB used in the Waneta 2017 Business Case. It should be noted that this LRB includes BC Hydro's one-third interest in Waneta, Site C and Revelstoke Unit 6.

11.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, p. 3; 2017 BCUC Site C Inquiry, Exhibit F1-1, pp. 7, 8, Exhibit A-24-2-1, Commission Illustrative Alternative Portfolio
Need for new resources

BC Hydro states on page 3 of the Application that based on the mid-level load forecast in the F2017-F2019 RRA, the LRB identifies a need for new resources in F2022.

1.11.2.2 For each row in Table K-3 and K-4 above, please (i) identify the year in which this data was last updated, (ii) explain whether there have been any significant changes since this date which could affect the reliability of these estimates (for example, to the SOP program, planned DSM etc.), and (iii) whether updated estimates are available for significant data changes as identified in (ii).

RESPONSE:

Table K-3 and K-4 were based on the LRB updated in 2016. Please refer to BCUC IR 1.11.2.2.1 for a more recent LRB.

11.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, p. 3; 2017 BCUC Site C Inquiry, Exhibit F1-1, pp. 7, 8, Exhibit A-24-2-1, Commission Illustrative Alternative Portfolio
Need for new resources

BC Hydro states on page 3 of the Application that based on the mid-level load forecast in the F2017-F2019 RRA, the LRB identifies a need for new resources in F2022.

1.11.2.2.1 Please provide an updated Table K-3 and K-4 above, using BC Hydro's most recent estimates for each row and explain any significant differences (Updated LRB).

RESPONSE:

Tables K-3 and K-4 provided in the BCUC Site C Inquiry only provide the LRB after planned resources. For completeness and for the purpose of answering other questions in this proceeding that refer to this response, we are providing the updates to the LRB tables both before and after planned resources (i.e., Tables K-1 to K-4 of the Site C Inquiry where Tables K-1 and K-2 do not include Site C, and Tables K-3 and K-4 include Site C). Please refer to Tables 1-4, which all include Site C, in section 3 below.

Tables 1-4 provide an updated LRB[1] that incorporates new and updated information as discussed more fully in section 1 below. This updated LRB is not a new long term load forecast. This update includes new supply information and incorporates adjustments to the May 2016 load forecast. The updated LRB in Table 1 below shows that the first year of LRB shortfall (before planned resources) has moved from fiscal 2022 (in the Application) to fiscal 2027.

Additional detailed information is provided below as follows: (1) new and updated information to the LRB; (2) the first year of deficit in the updated LRB; and (3) updated LRBs.

[1] BC Hydro notes in our applications subsequent to the F17-F19 RRA (i.e., BCUC Site C Inquiry [Tables K1-K4], Waneta 2017 Transaction), BC Hydro provided updates to the LRB which largely reflected revisions and re-allocations to certain values, and had no impact on the fiscal 2022 LRB shortfall.

SECTION 1: New and Updated Information

The key updates to the LRBs reflected in Tables 1-4 include:

a) Adjustments to the May 2016 Load Forecast;

b) Updates to our existing and committed resources; and

c) Updates to our planned resources (shown in Tables 3 and 4 only).

a) Adjustments to the May 2016 Load Forecast

BC Hydro's new long term load forecast has not yet been completed. However, we have made some updates to the May 2016 long term load forecast in response to certain issues raised previously by the BCUC that could be easily incorporated. Specifically, the following adjustments have been made:

- **The price elasticity factor has been updated from -0.05 to -0.1, based on findings of an electricity price elasticity study conducted by a third party consultant;**
- **Updated methodology and new information on LNG and LNG uncertainty bands, and**
- **Updated DSM plan developed for the F20-F21 RRA.**

Figure 1 below presents the May 2016 Load Forecast and the adjusted May 2016 Load Forecast for energy with their respective uncertainty bands. This figure also includes BC Hydro's short-term mid-load forecast (fiscal 2019 to fiscal 2024) from the F20-F21 RRA (October 2018 Load Forecast).[2] Figure 2 below presents a similar view for peak demand without a short term forecast. BC Hydro considers the adjusted May 2016 forecast is reasonable for the following reasons:

- **Although the short-term October 2018 Load Forecast suggests more modest load growth relative to the May 2016 forecast, it remains within the May 2016 forecast's band of uncertainty; and**
- **The adjusted May 2016 load forecast has not incorporated potential load growth of the CleanBC Plan announced on December 5, 2018 which is expected to increase demand due to electrification.**

[2] The methodology used to develop this short term forecast addresses many of the issues raised previously by the BCUC.

b) Updates to existing and committed resources

The updated LRB reflects changes to existing and committed resources relative to the information provided in the Tables K-1 to K-4 (and the Tables 3-6 to 3-9 in the F17-F19 RRA), including the following:

- **The Heritage system capability has been updated to reflect new information, such as facility upgrades, major outage assumptions, Treaty and operational assumptions, and updated water records. BC Hydro notes that the Waneta 2017 Transaction, completed in 2018, does not impact the LRB as the lease with Teck extends past the forecast period;**

- **Future energy savings from codes and standards have been reallocated to existing and committed (i.e., were previously planned resources);**

- **The IPP forecast was updated from May 2016 to October 2018 to reflect updated IPP operational history and other expected changes to operations; and**

- **New EPAs, such as EPA renewals, and SOP EPAs that have been reallocated to existing and committed (i.e., were previously planned resources).**

BC Hydro notes that these changes to existing and committed resources are consistent with the information provided in the F20-F21 RRA.

c) Updates to planned resources

The updated LRB reflects the following material updates to planned resources relative to the information provided in Tables K-1 to K-4 (and the Tables 3-6 to 3-9 in the F17-F19 RRA):

- ***EPA renewals*. In addition to the IPP forecast updates discussed above, as a result of the recently announced Biomass Energy Program, which is part of Phase 1 of Government's Comprehensive Review, the renewal assumption for seven biomass projects has increased from 50 per cent to 80 per cent for energy, and from 50 per cent to 100 per cent for capacity. For all the other EPA renewals (including those biomass projects that are not eligible to participate in the Biomass Energy Program), the renewal percentage assumptions have not been changed to reflect the recent decision to use market price as an interim assumption for cost effectiveness. As such, these assumptions remain the same as in the BC Hydro May 2016 IPP forecast; and**

- ***Expected SOP and other First Nations commitments.* The Standing Offer Program (SOP) has been indefinitely suspended and accordingly SOP**

volumes have been reduced, with the exception of four First Nations clean energy projects under the SOP[3] and three other potential EPAs related to Impact Benefit Agreements with First Nations.

BC Hydro notes that these changes to planned resources are consistent with the information provided in the F20-F21 RRA.

SECTION 2: The First Year of Deficit in the Updated LRB

Table 1 demonstrates that the first year of energy deficit in the updated LRB is in fiscal 2027 (line 8 "surplus/(deficit)" of Table 1). Table 2 demonstrates that the first year of capacity deficit in the updated LRB is in fiscal 2023 (line 9 "surplus/(deficit)" of Table 2). BC Hydro notes that when evaluating the need for energy resources, such as EPA renewals:

- **The planning view of the LRB is applicable and is used to determine the first year of deficit. For an explanation of planning vs. operational view please see Appendix B of the Application; and**

- **The LRB (before planned resources) - i.e., Table 1 – is applicable because all planned resources, including EPA renewals, are not committed. Table 3 (after planned resources) would be used for determining the need for a resource that is not included in our planned resources.[4]**

SECTION 3: BC HYDRO'S UPDATED LOAD RESOURCE BALANCE TABLES

As discussed above,

- **Tables 1 to 4 show the planning view of the updated LRB;**

- **Tables 1 and 2 show the LRB with only existing and committed resources (before planned resources); and**

- **Tables 3 and 4 show the LRB after planned resources.**

[3] There are five excepted First Nation clean energy projects; one EPA has already been signed and is now an existing and committed resource.

[4] Please note that Tables K-3 and K-4 from the Site C Inquiry, similar to Table 3 and Table 4 (both after planned resources), would also not be applicable because they include planned resources.

Table 1 Planning view of energy load resource balance based on existing and committed resources

	(GWh)		F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
	Existing and Committed Heritage Resources																		
1	Heritage Resources (including Site C)	(a)	46,916	46,916	46,916	46,916	47,282	50,808	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202
2	***Existing and Committed IPP Resources***	(b)	16,898	16,607	16,293	14,173	13,762	13,511	13,221	13,113	13,006	12,537	11,766	11,229	10,949	10,824	10,518	9,809	8,283
3	**Total Supply (Planning View)**	(c) = a + b	63,814	63,523	63,209	61,089	61,043	64,319	65,423	65,315	65,208	64,739	63,968	63,431	63,151	63,026	62,720	62,011	60,485
	Demand - Integrated System Total Gross Requirements																		
4	Adjusted 2016 May Mid Load Forecast Before DSM (with -0.1 elasticity)	(d)	(61,129)	(62,066)	(63,444)	(64,672)	(66,252)	(68,201)	(69,563)	(71,047)	(72,030)	(72,990)	(74,057)	(75,128)	(76,283)	(77,204)	(78,129)	(78,946)	(79,815)
	Existing and Committed Demand Side Management & Others Measures																		
5	F16-F19 DSM Portfolio Savings - F20-F21 RRA		2,557	2,463	2,388	2,352	2,332	2,311	2,274	2,235	2,194	2,148	2,111	2,050	1,964	1,884	1,766	1,678	1,577
6	F20+ Codes & Standards - F20-F21 RRA and Voltage and VAR Optimization		220	617	967	1,238	1,483	1,715	1,921	2,108	2,271	2,427	2,583	2,724	2,853	2,982	3,110	3,240	3,368
7	Sub-total	(e)	2,777	3,080	3,355	3,590	3,815	4,026	4,195	4,343	4,465	4,575	4,694	4,774	4,817	4,866	4,876	4,918	4,945
8	**Surplus / (Deficit)**	(f) = c + d + e	**5,461**	**4,538**	**3,120**	**7**	**(1,393)**	**144**	**55**	**(1,389)**	**(2,357)**	**(3,675)**	**(5,395)**	**(6,923)**	**(8,315)**	**(9,312)**	**(10,533)**	**(12,018)**	**(14,384)**
9	**Surplus / Deficit as % of Net Load**		**109%**	**108%**	**105%**	**100%**	**98%**	**100%**	**100%**	**98%**	**97%**	**95%**	**92%**	**90%**	**88%**	**87%**	**86%**	**84%**	**81%**
10	**Small Gap Surplus / (Deficit)**		**8,849**	**8,362**	**7,404**	**4,654**	**3,711**	**5,782**	**5,988**	**4,758**	**4,037**	**2,978**	**1,519**	**216**	**(841)**	**(1,587)**	**(2,632)**	**(3,848)**	**(5,987)**
11	**Large Gap Surplus / (Deficit)**		**1,125**	**(296)**	**(2,363)**	**(6,947)**	**(8,637)**	**(7,382)**	**(8,106)**	**(9,846)**	**(11,144)**	**(12,874)**	**(15,054)**	**(16,846)**	**(18,518)**	**(19,773)**	**(21,267)**	**(23,032)**	**(25,694)**

Table 2 Peak capacity load resource balance based on existing and committed resources

	(MW)		F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
	Existing and Committed Heritage Resources																		
1	Heritage Hydroelectric (including Site C)	(a)	11,588	11,588	11,588	11,528	11,588	12,319	12,319	12,676	12,676	12,676	12,676	12,676	12,262	12,262	12,733	12,733	12,733
2	***Existing and Committed IPP Resources***	(b)	1,536	1,455	1,482	1,207	1,196	1,136	1,104	1,104	1,091	1,080	948	912	908	884	835	590	517
3	14% of Supply Requiring Reserves - excl. Rio Tinto Alcan and FortisBC	(c)	(1,808)	(1,796)	(1,792)	(1,745)	(1,752)	(1,853)	(1,848)	(1,898)	(1,897)	(1,895)	(1,877)	(1,871)	(1,813)	(1,810)	(1,869)	(1,865)	(1,855)
4	**Effective Load Carrying Capability**	(d) = a + b + c	11,317	11,246	11,278	10,990	11,032	11,602	11,575	11,882	11,870	11,861	11,748	11,716	11,357	11,336	11,699	11,458	11,395
	Demand - Integrated System Total Gross Requirements																		
5	Adjusted 2016 May Mid Load Forecast Before DSM (with -0.1 elasticity)	(e)	(11,340)	(11,502)	(11,704)	(11,930)	(12,260)	(12,508)	(12,709)	(12,900)	(13,133)	(13,345)	(13,574)	(13,801)	(14,026)	(14,257)	(14,485)	(14,723)	(14,953)
	Existing and Committed Demand Side Management & Others Measures																		
6	F16-F19 DSM Portfolio Savings - F20-F21 RRA		476	465	451	442	435	426	417	407	398	387	378	367	352	338	325	315	301
7	F20+ Codes & Standards - F20-F21 RRA		43	129	198	246	288	327	360	390	416	440	463	484	503	521	544	568	591
8	Sub-total	(f)	519	594	649	688	723	753	777	797	814	827	841	851	855	859	869	883	892
9	**Surplus / (Deficit)****	(g) = d + e + f	**496**	**338**	**223**	**(251)**	**(505)**	**(153)**	**(357)**	**(221)**	**(449)**	**(657)**	**(985)**	**(1,234)**	**(1,813)**	**(2,062)**	**(1,917)**	**(2,382)**	**(2,666)**
10	**Surplus / Deficit as % of Net Load ****		**105%**	**103%**	**102%**	**98%**	**96%**	**99%**	**97%**	**98%**	**96%**	**95%**	**92%**	**90%**	**86%**	**85%**	**86%**	**83%**	**81%**
11	**Small Gap Surplus / (Deficit)****		**1,111**	**1,031**	**1,002**	**611**	**427**	**857**	**708**	**886**	**710**	**556**	**282**	**80**	**(435)**	**(628)**	**(444)**	**(850)**	**(1,083)**
12	**Large Gap Surplus / (Deficit)****		**(318)**	**(574)**	**(859)**	**(1,528)**	**(1,822)**	**(1,564)**	**(1,863)**	**(1,756)**	**(2,045)**	**(2,322)**	**(2,735)**	**(3,034)**	**(3,666)**	**(3,969)**	**(3,882)**	**(4,411)**	**(4,760)**

** Capacity load resource balances are only shown in Planning View.

Table 3 Planning view of the energy load resource balance after planned resources

	(GWh)		F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
1	***Existing and Committed Heritage Resources (incl. Site C)***	(a)	46,916	46,916	46,916	46,916	47,282	50,808	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202
2	***Existing and Committed IPP Resources***	(b)	16,898	16,607	16,293	14,173	13,762	13,511	13,221	13,113	13,006	12,537	11,766	11,229	10,949	10,824	10,518	9,809	8,283
	Future Supply-Side Resources																		
3	IPP Renewals		593	1,105	1,201	3,430	3,789	3,990	4,267	4,350	4,434	4,838	5,365	5,829	5,963	6,003	6,241	6,889	8,177
4	Expected SOP Projects and other First Nations Commitments		67	145	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226
5	Rev 6		-	-	-	-	-	-	-	-	-	-	11	26	26	26	26	26	26
6	Sub-total	(c)	659	1,250	1,427	3,656	4,015	4,216	4,493	4,576	4,660	5,064	5,602	6,081	6,215	6,255	6,493	7,141	8,429
7	**Total Supply (Planning View)**	(d) = a + b + c	64,473	64,774	64,635	64,745	65,058	68,535	69,916	69,891	69,868	69,804	69,570	69,512	69,366	69,280	69,213	69,152	68,914
	Demand - Integrated System Total Gross Requirements																		
8	Adjusted 2016 May Mid Load Forecast Before DSM (with -0.1 elasticity)	(e)	(61,129)	(62,066)	(63,444)	(64,672)	(66,252)	(68,201)	(69,563)	(71,047)	(72,030)	(72,990)	(74,057)	(75,128)	(76,283)	(77,204)	(78,129)	(78,946)	(79,815)
	Existing and Committed Demand Side Management & Others Measures																		
9	F16-F19 DSM Portfolio Savings - F20-F21 RRA		2,557	2,463	2,388	2,352	2,332	2,311	2,274	2,235	2,194	2,148	2,111	2,050	1,964	1,884	1,766	1,678	1,577
10	F20+ Codes & Standards - F20-F21 RRA and Voltage and VAR Optimization		220	617	967	1,238	1,483	1,715	1,921	2,108	2,271	2,427	2,583	2,724	2,853	2,982	3,110	3,240	3,368
	Planned Demand Side Management Measures																		
11	F20+ Rates - F20-F21 RRA		64	129	145	149	145	142	140	139	137	137	136	136	136	136	136	136	136
12	F20+ Programs - F20-F21 RRA		128	382	570	699	833	954	1,070	1,187	1,298	1,397	1,492	1,510	1,515	1,561	1,592	1,619	1,632
13	Sub-total	(f)	2,969	3,591	4,070	4,438	4,793	5,122	5,405	5,669	5,900	6,109	6,322	6,420	6,468	6,563	6,604	6,673	6,713
14	**Surplus / (Deficit)**	(g) = d + e + f	**6,313**	**6,299**	**5,261**	**4,511**	**3,600**	**5,456**	**5,758**	**4,514**	**3,738**	**2,923**	**1,835**	**804**	**(449)**	**(1,361)**	**(2,312)**	**(3,122)**	**(4,187)**
15	**Surplus / Deficit as % of Net Load**		**111%**	**111%**	**109%**	**107%**	**106%**	**109%**	**109%**	**107%**	**106%**	**104%**	**103%**	**101%**	**99%**	**98%**	**97%**	**96%**	**94%**
16	**Small Gap Surplus / (Deficit)**		**9,682**	**10,071**	**9,473**	**9,071**	**8,604**	**10,983**	**11,569**	**10,526**	**9,986**	**9,420**	**8,584**	**7,776**	**6,857**	**6,191**	**5,411**	**4,865**	**4,025**
17	**Large Gap Surplus / (Deficit)**		**1,957**	**1,413**	**(294)**	**(2,530)**	**(3,744)**	**(2,181)**	**(2,526)**	**(4,078)**	**(5,195)**	**(6,432)**	**(7,989)**	**(9,286)**	**(10,819)**	**(11,995)**	**(13,225)**	**(14,319)**	**(15,682)**

Table 4 Peak capacity load resource balance after planned resources

	(MW)		F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
	Existing and Committed Heritage Resources																		
1	Heritage Hydroelectric	(a)	11,588	11,588	11,588	11,528	11,588	12,319	12,319	12,676	12,676	12,676	12,676	12,676	12,262	12,262	12,733	12,733	12,733
2	***Existing and Committed IPP Resources***	(b)	1,536	1,455	1,482	1,207	1,196	1,136	1,104	1,104	1,091	1,080	948	912	908	884	835	590	517
	Future Supply-Side Resources																		
3	IPP Renewals		143	225	254	529	538	547	576	576	586	597	662	640	628	643	680	925	966
4	Expected SOP Projects and other First Nations Commitments		12	12	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
5	REV 6		0	0	0	0	0	0	0	0	0	0	488	488	488	488	488	488	488
6	Sub-total	(c)	155	236	273	548	557	566	594	595	605	616	1,169	1,147	1,135	1,150	1,187	1,432	1,473
7	14% of Supply Requiring Reserves - excl. Rio Tinto Alcan and FortisBC	(d)	(1,829)	(1,829)	(1,830)	(1,822)	(1,830)	(1,932)	(1,932)	(1,982)	(1,981)	(1,981)	(2,040)	(2,032)	(1,972)	(1,971)	(2,035)	(2,066)	(2,061)
8	**Effective Load Carrying Capability**	(e) = a+b+c+d	11,450	11,450	11,513	11,461	11,512	12,088	12,086	12,393	12,390	12,390	12,753	12,702	12,334	12,326	12,720	12,689	12,662
	Demand - Integrated System Peak																		
9	Adjusted 2016 May Mid Load Forecast Before DSM (with -0.1 elasticity)	(f)	(11,340)	(11,502)	(11,704)	(11,930)	(12,260)	(12,508)	(12,709)	(12,900)	(13,133)	(13,345)	(13,574)	(13,801)	(14,026)	(14,257)	(14,485)	(14,723)	(14,953)
	Existing and Committed Demand Side Management & Others Measures																		
10	F16-F19 DSM Portfolio Savings - F20-F21 RRA		476	465	451	442	435	426	417	407	398	387	378	367	352	338	325	315	301
11	F20+ Codes & Standards - F20-F21 RRA		43	129	198	246	288	327	360	390	416	440	463	484	503	521	544	568	591
	Planned Demand Side Management Measures																		
12	F20+ Rates - F20-F21 RRA		8	15	17	17	17	16	16	15	15	15	15	15	14	14	14	14	14
13	F20+ Programs - F20-F21 RRA		19	58	87	108	129	148	166	183	199	213	225	229	232	237	244	250	254
14	Sub-total	(g)	546	667	753	813	869	917	959	995	1,028	1,055	1,081	1,095	1,101	1,110	1,127	1,147	1,160
15	**Surplus / (Deficit)****	(h) = e + f + g	**656**	**615**	**562**	**345**	**121**	**497**	**336**	**488**	**285**	**101**	**260**	**(3)**	**(591)**	**(822)**	**(638)**	**(887)**	**(1,131)**
16	**Surplus / Deficit as % of Net Load ****		**106%**	**106%**	**105%**	**103%**	**101%**	**104%**	**103%**	**104%**	**102%**	**101%**	**102%**	**100%**	**95%**	**94%**	**95%**	**93%**	**92%**
17	**Small Gap Surplus / (Deficit)****		**1,268**	**1,298**	**1,327**	**1,192**	**1,034**	**1,488**	**1,380**	**1,573**	**1,420**	**1,288**	**1,501**	**1,284**	**761**	**586**	**808**	**617**	**422**
18	**Large Gap Surplus / (Deficit)****		**(161)**	**(307)**	**(534)**	**(947)**	**(1,214)**	**(933)**	**(1,192)**	**(1,069)**	**(1,335)**	**(1,590)**	**(1,516)**	**(1,831)**	**(2,470)**	**(2,754)**	**(2,630)**	**(2,944)**	**(3,254)**

Figure 1 Comparison of load forecasts for energy. All forecasts are after DSM and with LNG.

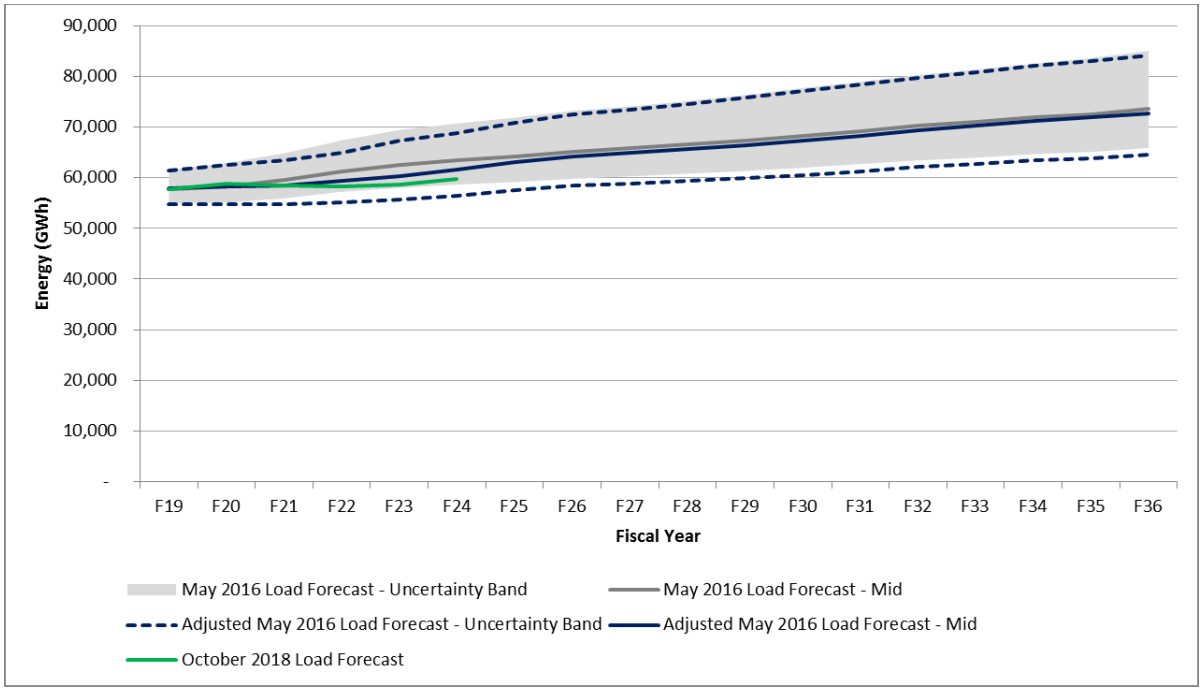
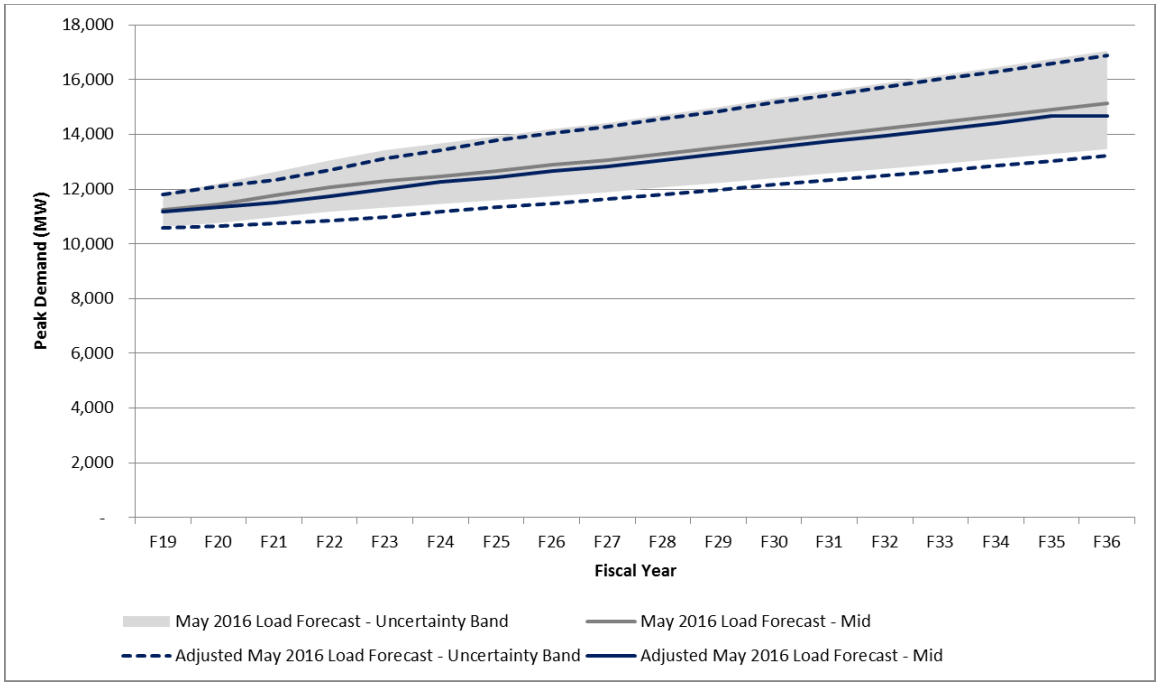


Figure 2 Comparison of load forecasts for peak demand. All forecasts are after DSM and with LNG.



11.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, p. 3; 2017 BCUC Site C Inquiry, Exhibit F1-1, pp. 7, 8, Exhibit A-24-2-1, Commission Illustrative Alternative Portfolio
Need for new resources

BC Hydro states on page 3 of the Application that based on the mid-level load forecast in the F2017-F2019 RRA, the LRB identifies a need for new resources in F2022.

1.11.3 For the purpose of identifying the year when there is a need for new resources, please provide a working spreadsheet in the format consistent with tab 'Energy & Capacity Gap' of the Site C Commission Illustrative Alternative Portfolio. Please use the following assumptions:

- Row 8, 15, 24, 31, 40, 47: please provide two versions of the spreadsheet. Version 1 should use the Site C LRB, and Version 2 should use the Updated LRB (if available).
- Rows 9, 16, 25, 32, 41, 48: For Version 1, please replace this line item with 'IPP Renewals', and include in this row energy/capacity related to BC Hydro forecast IPP renewals less any IPP renewals that BC Hydro has committed to. For Version 2, in addition to IPPs, please include any SOP energy/capacity that BC Hydro no longer considers a planned resource.
  For capacity requirements, please adjust where appropriate for the 14% of supply requiring reserves and explain the adjustment made.
- Where BC Hydro is still expected to be in an energy/capacity surplus situation beyond F2036, for Version 1 please use the same ramp-up estimates as used in the Site C Commission Illustrative Alternative Portfolio (800 GWh/year and 200 MW/year). For Version 2 please use BC Hydro's ramp-up estimate (if different) and explain the assumption used.

RESPONSE:

The spreadsheets requested above are based on the Site C BCUC Illustrative Portfolio format which presented an operational view after planned resources. For the purposes of evaluating need in the Application, the LRB was the planning view

and before planned resources as provided in Table 3-6 of Appendix B (line 12) of the Application. Please see BC Hydro's response to BCUC IR 1.11.2.2.1 (section 2) for the first year of deficit in the updated LRB.

We are providing the spreadsheets in planning view (the view for determining need) with the requested changes.

BC Hydro
Power smart

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

11.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, p. 3; 2017 BCUC Site C Inquiry, Exhibit F1-1, pp. 7, 8, Exhibit A-24-2-1, Commission Illustrative Alternative Portfolio
Need for new resources

BC Hydro states on page 3 of the Application that based on the mid-level load forecast in the F2017-F2019 RRA, the LRB identifies a need for new resources in F2022.

1.11.3.1 Resulting from the analysis and assumptions above, please identify for each load forecast (high, mid, low) and version (Version 1, 2), the year in BC Hydro considers the energy and/or any capacity from the EPAs included this Application will not be surplus to BC Hydro's requirements.

RESPONSE:

The table below identifies the years in which the requested analysis indicates the energy and capacity from the EPAs included in this Application will not be surplus to BC Hydro's requirements. BC Hydro notes that this analysis assumes that the future DSM volumes are committed resources. However, BC Hydro has not committed to this level of future DSM volumes (above the F20-F21 RRA plan).

Please refer to BC Hydro's response to BCUC IR 1.11.3 for the working spreadsheets.

	Load Forecast	V1 – Site C (fiscal year)	V2 - Updated (fiscal year)
Energy	High	2022	2022
	Mid	2029[1]	2028[1]
	Low	2036	2034
Capacity	High	2020	2020
	Mid	2022	2023
	Low	2035	2035

[1] **For V1 – Site C, fiscal 2029 is the first year of a long term deficit, however there is one temporary deficit year in fiscal 2024; for V2 – Updated, fiscal 2028 is the first year of a long term deficit however there is one temporary deficit year in fiscal 2024.**

11.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, p. 3; 2017 BCUC Site C Inquiry, Exhibit F1-1, pp. 7, 8, Exhibit A-24-2-1, Commission Illustrative Alternative Portfolio
Need for new resources

BC Hydro states on page 3 of the Application that based on the mid-level load forecast in the F2017-F2019 RRA, the LRB identifies a need for new resources in F2022.

1.11.3.1 Resulting from the analysis and assumptions above, please identify for each load forecast (high, mid, low) and version (Version 1, 2), the year in BC Hydro considers the energy and/or any capacity from the EPAs included this Application will not be surplus to BC Hydro's requirements.

1.11.3.1.1 Please also estimate the year in which energy delivered during the freshet period (May to June) would not be surplus to requirements.

RESPONSE:

BC Hydro cannot estimate the year in which energy delivered during the freshet period would not be surplus to requirements. How long the freshet energy oversupply situation will last will depend on variables such as the annual profile of future demand growth and the type of resources acquired to meet growth.

In general, BC Hydro expects, on a planning basis (i.e., under average water conditions), to have energy surplus during freshet for some time. However, the actual condition is subject to operational factors including water variability and fluctuations in load.

Please also refer to BC Hydro's response to CEC IR 1.19.2

12.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, p. 3, Appendix B, pp. 6, 7, Table 3-8, Table 3-9; 2017 BCUC Site C Inquiry, Exhibit A-24, Appendix A, p. 7; Exhibit F1-1, Appendix K, Table K-3, Table K-4; BC Hydro F2017 to F2019 RRA, Tables 3-8, Tables 3-9
Need for new resources

In the 2017 BCUC Site C Final Report, Appendix A, p. 7 the BCUC found that the Kootenay Canal Grohman Narrows project and the Alouette redevelopment project (incremental to decommissioning) and the GMS Units 1-5 capacity increase projects are alternatives to Site C with the potential to provide competitively priced energy and capacity.

1.12.1 Please explain whether BC Hydro's planned resources provided in Table K-3 and K-4 in Appendix K to Exhibit F1-1 of the Site C Inquiry and Tables 3-8 and 3-9 from the BC Hydro F2017 to F2019 RRA (included at pages 6 and 7 of Appendix B to the Application) include the Grohman Narrows project, the Alouette redevelopment project (incremental to decommissioning) and the GMS Units 1-5 capacity increase projects. If no, please explain why not.

RESPONSE:

No, BC Hydro's planned resources provided during the Site C Inquiry and F17-F19 RRA did not include the Grohman Narrows project, the Alouette redevelopment project, or the GMS Units 1-5 capacity increase projects. They were not included because BC Hydro did not have a plan to pursue them.

12.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, p. 3, Appendix B, pp. 6, 7, Table 3-8, Table 3-9; 2017 BCUC Site C Inquiry, Exhibit A-24, Appendix A, p. 7; Exhibit F1-1, Appendix K, Table K-3, Table K-4; BC Hydro F2017 to F2019 RRA, Tables 3-8, Tables 3-9
Need for new resources

In the 2017 BCUC Site C Final Report, Appendix A, p. 7 the BCUC found that the Kootenay Canal Grohman Narrows project and the Alouette redevelopment project (incremental to decommissioning) and the GMS Units 1-5 capacity increase projects are alternatives to Site C with the potential to provide competitively priced energy and capacity.

1.12.1.1 Please estimate the (i) energy/capacity volumes available and (ii) energy/capacity cost of these projects. Please comment on whether they are lower cost than the EPAs included in this Application.

RESPONSE:

The public version of this response has been redacted to maintain in confidence commercially sensitive information. Please refer to BC Hydro's letter of August 24, 2018 (Exhibit B-2) for a description of the information redacted in BC Hydro's Application and the rationale for these redactions.

The estimated energy and capacity volumes and costs for the three referenced projects are provided in Table 1 below.

BC Hydro notes the following when comparing the costs of the referenced projects to the EPA renewals in the Application:

- **The GMS project only provides capacity, so it does not provide an appropriate point of reference for comparing with EPAs that provide energy; and**

- **The estimated costs of the referenced projects contain significant cost uncertainty because they are preliminary estimates; whereas, the EPA prices are known contractual prices.**

Although the levelized EPA price for the [redacted] in the Application is higher than the estimated UECs shown in Table 1 below; BC Hydro believes all three EPA renewals compare favourably to the UECs shown because there is significantly less cost risk and there are the benefits to the EPA renewals, such as

the value associated with the additional generation provided to Seton Dam Generating Station.

Table 1 Project Energy and Capacity Volumes and Costs[1]

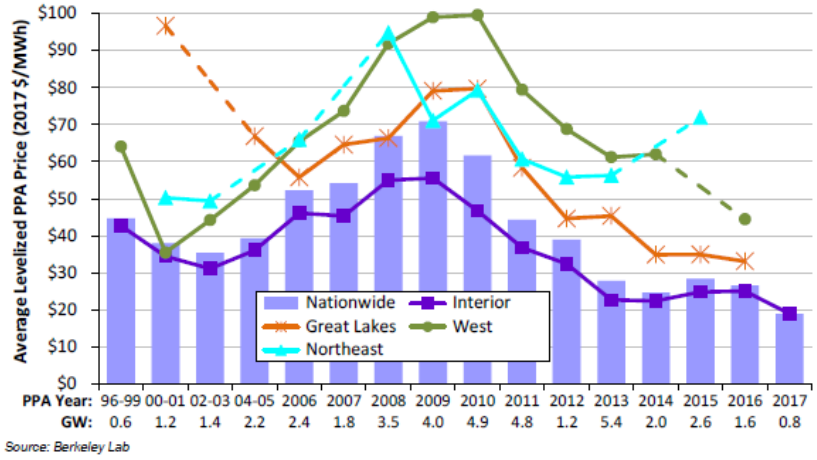
Project	Energy (GWh/yr)	UEC ($/MWh)	Capacity (MW)	UCC ($/kW-yr)
Kootenay Canal Grohman Narrows	**89**	**51**		
Alouette redevelopment	**61**	**50**	**21**	**145**
GMS Units 1-5 capacity increase			**100**	**65**

[1] All unit energy cost (UEC) and unit capacity cost (UCC) at Point-of-Interconnection (POI) are calculated assuming 4 per cent real WACC and presented in 2017 dollar (to be in the same year as the levelized EPA prices in the Application).

13.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; US Department of Energy 2017 Wind Technologies Market Report, p. 59[1]
Wind levelized cost (plant gate) – regional variation

Page 59 of the US Department of Energy 2017 Wind Technologies Market Report includes the following chart of generation weighted average levelized wind power purchase agreement (PPA) prices by PPA execution date and region (in US $):



1.13.1 For the purpose of determining BC Hydro's opportunity cost when it needs new resources, please explain which resource option (or portfolio of options) BC Hydro considers should be used (for example, wind, solar, geothermal, energy efficiency etc.)

RESPONSE:

At the time of negotiating and executing these EPA renewals, BC Hydro's approach to assessing the need for new resources (i.e., beyond existing and committed resources) had been to consider DSM and EPA renewals as the next most cost effective energy resources until there is a need for new greenfield supply. BC Hydro considers onshore wind the next most cost effective greenfield energy resource in B.C.

[1] https://www.energy.gov/eere/wind/downloads/2017-wind-technologies-market-report

13.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; US Department of Energy 2017 Wind Technologies Market Report, p. 59[1]
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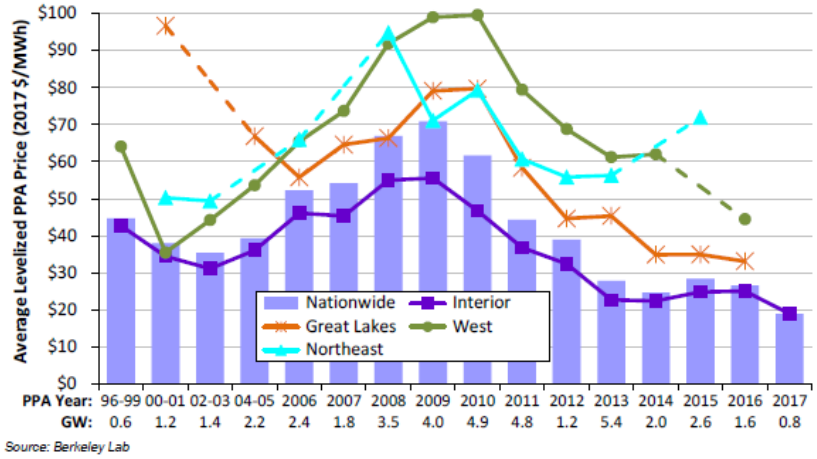
Page 59 of the US Department of Energy 2017 Wind Technologies Market Report includes the following chart of generation weighted average levelized wind power purchase agreement (PPA) prices by PPA execution date and region (in US $):



1.13.2 Does BC Hydro consider that wind PPA prices in BC would be reasonably similar to the wind PPA prices achieved in the West region above? Please explain why/why not.

RESPONSE:

BC Hydro notes that the wind PPA price shown for the West region in 2016 is based on a very small sample size (two projects). This is a very small data pool from which to draw conclusions on whether wind PPA prices in B.C. would be reasonably similar. However, we offer the following comments:

- **It would be reasonable to expect that wind prices in the West region are higher than the Interior region due in part to differences in terrain; and**

[1] https://www.energy.gov/eere/wind/downloads/2017-wind-technologies-market-report

- **The U.S. PPA prices shown in the graph above include the Production Tax Credit (PTC) which effectively lowers the cost of wind energy. The PTC is not available to Canadian wind projects.**

Please also refer to BC Hydro's response to BCUC IR 1.14.1.

14.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; Alberta Electric System Operator (AESO), REP Round 1 Results[1], Renewable Electricity Program (REP)[2]; SaskPower, 200 MW wind power news release, July 6, 2017[3]; BC Hydro Waneta 2017 Transaction Application Decision and Order G-130-18, p. 46
Wind levelized cost and timeline – Alberta, Saskatchewan

The AESO website provides information on the results of the Renewable Electricity Program (REP) Round 1: "On Dec.13, 2017, the Government of Alberta announced the results of Round 1 of the Renewable Electricity Program (REP). REP Round 1 successfully delivered nearly 600 MW of wind generation at a weighted average bid price of $37/MWh – setting a new record in Canada for the lowest renewable electricity pricing."

The AESO timeline for REP Round 2 (up to 300 MW and includes a minimum 25 per cent Indigenous equity ownership) and Round 3 (up to 400MW) is provided below for projects with a target in-service date of June 30, 2021:

SaskPower July 6, 2017 news release states that it has a competitive process for 200 MW of utility-scale wind, with the successful proponent expected to be announced in fall 2018, with the project expected to be in-service in early 2021.

Page 46 of the BC Hydro Waneta 2017 Transaction Application Decision and Order G-130-18 stated:

The Panel also notes that CEABC, BCSEA-SCBC and CEC all believe the use of wind energy at $60/MWh is appropriate. For its part, BCOAPO notes that the value of the Waneta 2017 Transaction would still be positive for any blended LRMC higher than $50/MWh. The Panel is also satisfied that using $60/MWh for wind resources is appropriate.

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1 Alberta Electric System Operator, Alberta's Renewable Electricity Program (REP) Round 1 Results, date December 31, 2017: https://www.aeso.ca/market/renewable-electricity-program/rep-round-1-results/

2 https://www.aeso.ca/market/renewable-electricity-program/

3 https://wcms.saskpower.com/about-us/media-information/news-releases/2018/03/saskpowers-200-mw-wind-project-moves-to-rfp-phase-of-competition

1.14.1 To what extent does BC Hydro consider that Alberta/Saskatchewan's successful wind bids (in $/MWh) are indicative of $/MWh bids that could be achieved in BC if a similar competitive process was undertaken? Please explain.

RESPONSE:

The recent successful wind power bids in Alberta and Saskatchewan are useful for considering the wind prices that could be achieved in B.C. but are not indicative of B.C. pricing.[4]

To consolidate responses related to wind costs and to answer other related questions in this proceeding, this response provides a discussion of jurisdictional comparisons as follows:

a) Recent declining pricing trends in global and domestic markets;
b) Market-specific factors in Alberta and Saskatchewan that have contributed to recent low wind pricing; and
c) Geographical factors that are expected to influence pricing in B.C.

(a) Recent declining pricing trends

Wind prices have been on a global downward trend since 2010, primarily due to technological development resulting in declining wind turbine costs and increasing turbine efficiencies. Beyond these technological factors that apply to the cost of wind projects generally, additional market-specific forces have resulted in much sharper declines in wind prices over the last few years in certain jurisdictions. Notably, in addition to recent low prices in Alberta and Saskatchewan, low wind prices have been realized in Morocco (US$30/MWh in 2018), Brazil (US$31/MWh in 2017), Peru (US$38/MWh in 2016), and Mexico (US$22/MWh in 2016).

(b) Market-specific factors in Alberta and Saskatchewan

The Alberta Renewable Energy Program Phase 1 (Dec 2017) resulted in record low wind bids in Canada that ranged between $31/MWh and $43/MWh, with a weighted average cost of $37/MWh. For the Phase 2 and Phase 3 of the Alberta Renewable Energy Program, announced in December 2018, the average winning bid price

[4] Note that bid prices are not directly comparable to the LRMC of $104/MWh in this Application (which is now outdated). The $104/MWh includes the cost of wind energy at point of interconnection ($84/MWh) as well as BC Hydro's cost to integrate and deliver that energy to the load center in Lower Mainland.

increased slightly to $38/MWh and $40/MWh, respectively. For Saskpower's 2018 Request for Proposal, the average price for the 29 submitted bids was $42/MWh, with the winning bid "coming in well below that".[5]

The market-specific factors that are likely influencing these low prices are as follows:

- **Increased bidding competitiveness by large, global developers enabled through auction mechanisms. Wind proponents may also be submitting very low wind bids in an effort to gain a foothold in certain markets;**

- **Low financing costs and an investor appetite for renewable projects. In addition, large developers may be able to achieve high debt-to-equity ratios, as well as access cheap debt which enables them to lower their weighted average cost of capital;**

- **Increased competition among turbine manufacturers, which would be beneficial for turbine purchasers;**

- **Where an established wind service sector exists, lower Operations & Maintenance (O&M) costs may be achieved through more competitive pricing;**

- **Participation of larger developers, whereby large national or global developers can negotiate lower turbine as well as O&M costs, and may also be able to implement more favourable financing models; and**

- **Increased design life of turbines which impact the terminal value. If the turbine/project design life exceeds the contract length, it is possible that wind proponents are including a terminal value for their project which would allow for lower bid prices.**

The regional market structure for power acquisition as well as the nature of the power acquisition process itself will largely determine whether these market forces will influence the cost of wind power in a given jurisdiction.

All of the factors noted above may play a role in B.C. if a competitive acquisition process with long-term targets were to be undertaken. However, at this time, it is uncertain whether these market forces would also manifest in B.C. and, therefore, the degree to which they may drive wind prices in B.C. lower is also uncertain.

[5] https://www.saskpower.com/about-us/media-information/news-releases/potentia-renewables-to-build-200-megawatt-wind-power-facility-near-assiniboia

(c) Geographical factors

Even assuming the market-specific factors identified above would manifest similarly in B.C., BC Hydro expects that B.C.'s wind prices would still be higher than those in Alberta or Saskatchewan due to more complex terrain and remote locations in B.C. An example of the difference in installed capital cost between Alberta and B.C. can be found by examining the capital costs published by Capital Power[6] for two wind projects, one built in Alberta, the other in B.C. The two projects, which were both commissioned in 2012, were roughly of the same size, and used the same turbine model. Analysis shows that the installed capital cost for the B.C. wind project was $790/kW or 38 per cent higher than the wind project in Alberta. We assume that most of this difference in cost was attributable to location and terrain.

[6] Capital Power states on its website (https://www.capitalpower.com/generationportfolio/CA/Pages/default.aspx) that the capital cost for the Halkirk Wind Project in Alberta was $314.2 million or $2,094/kW. The Quality Wind Project in BC cost $409.5 million or 2,884/kW. Both estimates include interconnection costs.

14.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; Alberta Electric System Operator (AESO), REP Round 1 Results[1], Renewable Electricity Program (REP)[2]; SaskPower, 200 MW wind power news release, July 6, 2017[3]; BC Hydro Waneta 2017 Transaction Application Decision and Order G-130-18, p. 46
Wind levelized cost and timeline – Alberta, Saskatchewan

The AESO website provides information on the results of the Renewable Electricity Program (REP) Round 1: "On Dec.13, 2017, the Government of Alberta announced the results of Round 1 of the Renewable Electricity Program (REP). REP Round 1 successfully delivered nearly 600 MW of wind generation at a weighted average bid price of $37/MWh – setting a new record in Canada for the lowest renewable electricity pricing."

The AESO timeline for REP Round 2 (up to 300 MW and includes a minimum 25 per cent Indigenous equity ownership) and Round 3 (up to 400MW) is provided below for projects with a target in-service date of June 30, 2021:

SaskPower July 6, 2017 news release states that it has a competitive process for 200 MW of utility-scale wind, with the successful proponent expected to be announced in fall 2018, with the project expected to be in-service in early 2021.

Page 46 of the BC Hydro Waneta 2017 Transaction Application Decision and Order G-130-18 stated:

The Panel also notes that CEABC, BCSEA-SCBC and CEC all believe the use of wind energy at $60/MWh is appropriate. For its part, BCOAPO notes that the value of the Waneta 2017 Transaction would still be positive for any blended LRMC higher than $50/MWh. The Panel is also satisfied that using $60/MWh for wind resources is appropriate.

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1 Alberta Electric System Operator, Alberta's Renewable Electricity Program (REP) Round 1 Results, date December 31, 2017: https://www.aeso.ca/market/renewable-electricity-program/rep-round-1-results/

2 https://www.aeso.ca/market/renewable-electricity-program/

3 https://wcms.saskpower.com/about-us/media-information/news-releases/2018/03/saskpowers-200-mw-wind-project-moves-to-rfp-phase-of-competition

1.14.2 Please estimate how many years in BC it would take from identifying a need for new wind generation to having the projects in-service, and comment on whether this timeline is shorter/longer than in Alberta or Saskatchewan.

RESPONSE:

The number of years it takes from identifying a need for new wind generation to having a project in-service depends on 1) the acquisition process and degree of stakeholder engagement; 2) how advanced the project is in the development process (e.g., wind resource assessment, engineering studies, permitting, etc.,); and 3) the site characteristics (e.g., terrain/soil/vegetation, location, climate) which impacts the length of time required for construction.

A reasonable estimate of time between identification of need and in-service date for utility-scale wind projects in B.C. is five to seven years, based on the following breakdown:

- **Two to three years for call process to contract awards;**
- **One to two years for permitting and final design; and**
- **Two years for construction**

For example, the three wind projects from BC Hydro's Clean Power Call issued in June 2008 required approximately four, five and nine years to reach in-service respectively, each with a two-year construction period.

The terms of the renewable energy purchase contracts from Phase 1 of the Alberta Renewable Energy Program required projects to be built and on-line within a two-year period. This suggests that the winning bid projects were close to being shovel ready. In addition, it appears that wind projects in Alberta can be built in a little bit over a year.[4]

[4] For example, construction for the Whitla project began in September 2018, and is projected to be complete in the fourth quarter of 2019 (www.capitalpower.com/generationportfolio/CA/Pages/Whitla-Wind.aspx).

14.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; Alberta Electric System Operator (AESO), REP Round 1 Results[1], Renewable Electricity Program (REP)[2]; SaskPower, 200 MW wind power news release, July 6, 2017[3]; BC Hydro Waneta 2017 Transaction Application Decision and Order G-130-18, p. 46
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2 https://www.aeso.ca/market/renewable-electricity-program/

3 https://wcms.saskpower.com/about-us/media-information/news-releases/2018/03/saskpowers-200-mw-wind-project-moves-to-rfp-phase-of-competition

1.14.2.1 To what extent does BC Hydro consider that a load under-forecasting risk can be mitigated by procuring new generation as and when the need arises.

RESPONSE:

The extent to which BC Hydro can mitigate the risk of load under-forecasting by procuring new resources as and when needed will depend on (a) how fast load growth deviates from the forecast; (b) the magnitude of the deviation from the forecast; and (c) the length of time to bring new generation and/or transmission resources on-line. The acquisition of new generation and transmission resources often will have long lead times (i.e., many years). Additional factors such as cost and availability of resources including other demand side measures will also play a role in our ability to mitigate this risk. BC Hydro's projected energy surplus offers some mitigation against load under-forecasting risk in the near term.

Please also refer to BC Hydro's response to BCUC IR 1.8.4 with respect to BC Hydro's recently adopted conservative interim assumption for evaluating energy during surplus and deficit periods.

15.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 131; Appendix C, p. 4, 6; Exhibit F1-4, BCUC IR 1.1.0; National Renewable Energy Laboratory (NREL) 2018 Annual Technology Baseline (ATB) Spreadsheet [1]
Wind levelized cost (plant gate) - NREL

The 2017 BCUC Site C Final Report (Appendix C, pp. 4, 6) assumed an exchange rate of $1 CAN = $0.7979 USD and stated

Wind capital and operating costs are taken from the National Renewable Energy Laboratory (NREL) 2017 Annual Technology Baseline [land based wind tab, TRG4 mid]. NREL costs were increased by 10% in light of cost differences between BC Hydro's 2015 capital costs in BC Hydro's resource options spreadsheet and NREL 2015 estimates for wind investments of similar capacity factor. Costs were converted to Canadian dollars and historical inflation estimates for F2015 to F2018 were taken from BC Hydro's resource options spreadsheet.

Wind capital costs and operating costs were increased to account for transmission and road costs, with values derived from the project specific cost estimates from BC Hydro's resource options spreadsheet.

The U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy funds the development of the National Renewable Energy Laboratory's (NREL's) Annual Technology Baseline (ATB).[2] The 'land-based' wind tab (Future Projections) shows a 2018 levelized cost of energy TRG4 mid value of US $39/MWh, decreasing to US $30/MWh by 2036.

On page 131 of the Site C Inquiry Final Report it is shown that BC Hydro estimates the unit energy cost (generally wind) at the point of interconnection as Can $85/MWh. BC Hydro described its wind cost assumptions in Exhibit F1-4, BCUC IR 1.1.0.

1.15.1 For each key wind resource assumption described by BC Hydro in the Site C Inquiry above, please (i) provide the year that the analysis supporting this assumption was last updated and (ii) comment on whether BC Hydro considers that these

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

2 https://www.energy.gov/eere/analysis/downloads/2017-annual-technology-baseline

assumptions are reasonable now, and likely to still be reasonable (in today's dollars) in 10 years.

RESPONSE:

The assumptions underpinning the wind cost from the Site C Inquiry are described below:

Assumption	Year of update	Reasonable Now?	Reasonable in 10 years?
Wind resource potential	**2009**	**Yes**	**Yes**
Project location and size	**2009**	**Yes**	**Yes**
Turbine characteristics (size, hub height, power curve)	**2015**	**Yes**	**No**
Project life	**2015**	**Yes**	**No**
Loss factor	**2015**	**Yes**	**Yes**
Capital and O&M cost information	**2015**	**No**	**No**

15.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 131; Appendix C, p. 4, 6; Exhibit F1-4, BCUC IR 1.1.0; National Renewable Energy Laboratory (NREL) 2018 Annual Technology Baseline (ATB) Spreadsheet [1]
Wind levelized cost (plant gate) - NREL

The 2017 BCUC Site C Final Report (Appendix C, pp. 4, 6) assumed an exchange rate of $1 CAN = $0.7979 USD and stated

Wind capital and operating costs are taken from the National Renewable Energy Laboratory (NREL) 2017 Annual Technology Baseline [land based wind tab, TRG4 mid]. NREL costs were increased by 10% in light of cost differences between BC Hydro's 2015 capital costs in BC Hydro's resource options spreadsheet and NREL 2015 estimates for wind investments of similar capacity factor. Costs were converted to Canadian dollars and historical inflation estimates for F2015 to F2018 were taken from BC Hydro's resource options spreadsheet.

Wind capital costs and operating costs were increased to account for transmission and road costs, with values derived from the project specific cost estimates from BC Hydro's resource options spreadsheet.

The U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy funds the development of the National Renewable Energy Laboratory's (NREL's) Annual Technology Baseline (ATB).[2] The 'land-based' wind tab (Future Projections) shows a 2018 levelized cost of energy TRG4 mid value of US $39/MWh, decreasing to US $30/MWh by 2036.

On page 131 of the Site C Inquiry Final Report it is shown that BC Hydro estimates the unit energy cost (generally wind) at the point of interconnection as Can $85/MWh. BC Hydro described its wind cost assumptions in Exhibit F1-4, BCUC IR 1.1.0.

1.15.2 Does BC Hydro consider that the NREL 2018 Annual Technology Baseline (ATB) for onshore wind levelized cost estimate is a reasonable starting point to approximate the future (as opposed to current) cost of new generation supply in BC? If no, please explain why not.

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

[2] https://www.energy.gov/eere/analysis/downloads/2017-annual-technology-baseline

RESPONSE:

This question is interpreted as asking BC Hydro's view on the reasonableness of using the NREL ATB year-over-year projections of the future capital and OMA cost reductions of wind energy in the U.S. as a predictor of year-over-year reductions of capital and OMA costs wind energy in B.C. In general, the NREL ATB approach to forecasting the year-over-year reductions in capital and OMA costs using scenarios is a reasonable starting point.

15.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 131; Appendix C, p. 4, 6; Exhibit F1-4, BCUC IR 1.1.0; National Renewable Energy Laboratory (NREL) 2018 Annual Technology Baseline (ATB) Spreadsheet [1]
Wind levelized cost (plant gate) - NREL

The 2017 BCUC Site C Final Report (Appendix C, pp. 4, 6) assumed an exchange rate of $1 CAN = $0.7979 USD and stated

> Wind capital and operating costs are taken from the National Renewable Energy Laboratory (NREL) 2017 Annual Technology Baseline [land based wind tab, TRG4 mid]. NREL costs were increased by 10% in light of cost differences between BC Hydro's 2015 capital costs in BC Hydro's resource options spreadsheet and NREL 2015 estimates for wind investments of similar capacity factor. Costs were converted to Canadian dollars and historical inflation estimates for F2015 to F2018 were taken from BC Hydro's resource options spreadsheet.
>
> Wind capital costs and operating costs were increased to account for transmission and road costs, with values derived from the project specific cost estimates from BC Hydro's resource options spreadsheet.

The U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy funds the development of the National Renewable Energy Laboratory's (NREL's) Annual Technology Baseline (ATB).[2] The 'land-based' wind tab (Future Projections) shows a 2018 levelized cost of energy TRG4 mid value of US $39/MWh, decreasing to US $30/MWh by 2036.

On page 131 of the Site C Inquiry Final Report it is shown that BC Hydro estimates the unit energy cost (generally wind) at the point of interconnection as Can $85/MWh. BC Hydro described its wind cost assumptions in Exhibit F1-4, BCUC IR 1.1.0.

1.15.2.1 Please explain what adjustment BC Hydro considers appropriate, if any, to reflect cost differences between BC's point of interconnection wind capital costs and NREL estimates for wind investments of similar capacity factor.

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

[2] https://www.energy.gov/eere/analysis/downloads/2017-annual-technology-baseline

RESPONSE:

In general, the NREL estimates of wind costs are relevant for a typical U.S.-based wind project. It is not clear, from available documentation of the ATB database, what the initial assumptions were about geography, terrain, market conditions or grid infrastructure to inform their cost estimate. Accordingly, BC Hydro cannot determine what adjustments would be appropriate to account for the specific conditions in B.C. Please also refer to BC Hydro's response to BCUC IR 1.14.1.

16.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; NREL 2018 ATB Spreadsheet;
BC Hydro 2013 IRP, Appendix 3A-34, pp. 2, 9
Wind levelized cost - point-of-interconnection

In the NREL 2018 ATB 'land based wind' tab, cell T20 shows that the Techno-Resource Group (TRG) 4 has a weighted average net capacity factor of 43.5%.

1.16.1 Does BC Hydro consider that the Techno-Resource Group (TRG) 4 is the most appropriate TRG group for the purpose of estimating the cost of new wind generation supply in BC? If no, please explain which TRG group BC Hydro considers is most appropriate and why.

RESPONSE:

Yes because our most cost effective wind resources have similar characteristics (e.g., wind speeds) to those described in TRG 4.

16.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; NREL 2018 ATB Spreadsheet;
BC Hydro 2013 IRP, Appendix 3A-34, pp. 2, 9
Wind levelized cost - point-of-interconnection

The NREL 2018 ATB documentation for land-based wind includes within the capital expenditures definition project-related indirect costs and owners' costs such as environmental studies.[1] On page 2 of Appendix 3A-34 in the BC Hydro 2013 IRP, BC Hydro states that it includes a soft cost adder of 5 per cent to reflect cost expenditures such as environmental assessment, First Nations and stakeholder engagement. Page 9 of this Appendix shows that this adder was $5/MWh for the PC 28 wind project.

1.16.2 For the purpose of estimating BC Hydro's cost of new generation resources, please explain what adjustment for soft costs, if any, BC Hydro considers would be appropriate to make to the NREL capital cost assumption.

RESPONSE:

It is not clear, from available documentation of the ATB database, what the initial assumptions were about soft costs (e.g., environmental assessment, stakeholder engagement, permitting) to inform their cost estimate. Accordingly, BC Hydro cannot determine what incremental adjustments would be appropriate to account for the specific conditions in B.C. Please also refer to BC Hydro's response to BCUC IR 1.14.1.

The NREL capital cost assumptions are based on two source documents: the 2016 Wind Technologies Market Report,[2] and the 2016 Cost of Wind Energy Review.[3] The soft costs incorporated into the NREL report are described in the 2016 Cost of Wind Energy Review document as a component of the Balance of Plant costs, such as "Development Costs" or "Site Access and Staging". See the figure below for the representative breakdown of these and other costs from the 2016 Cost of Wind Energy Review.

1 https://atb.nrel.gov/electricity/2018/index.html?t=lw
2 https://www.energy.gov/sites/prod/files/2017/08/f35/2016_Wind_Technologies_Market_Report_0.pdf
3 https://www.nrel.gov/docs/fy18osti/70363.pdf

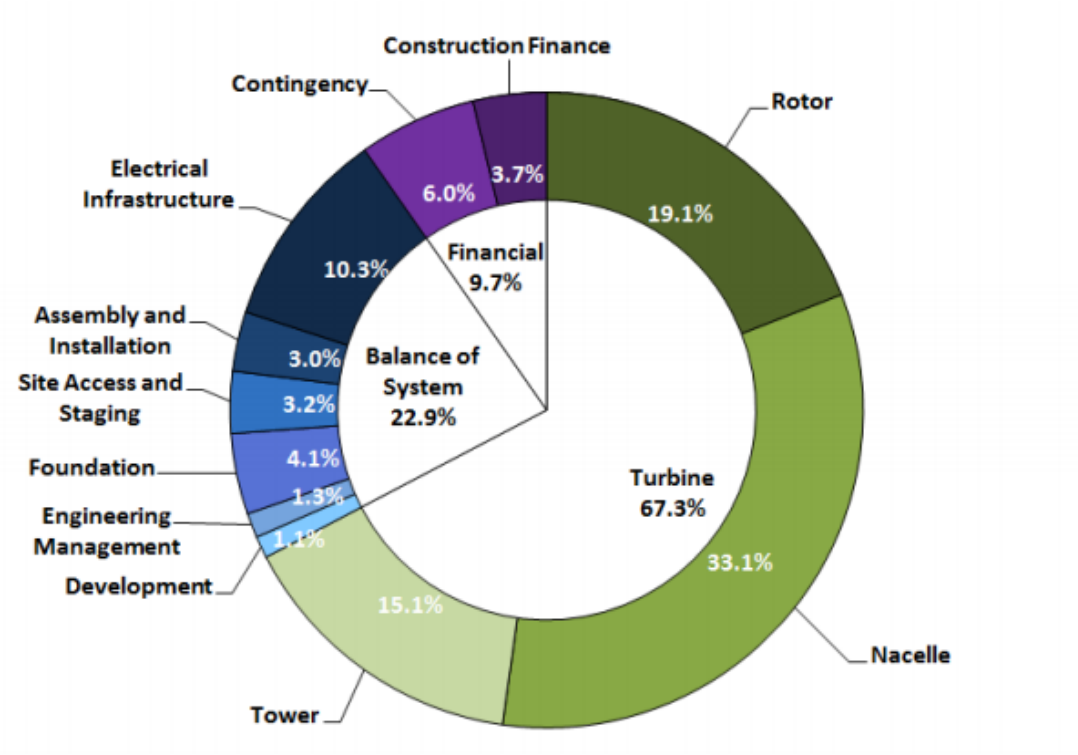


Figure 1. Capital expenditures for the land-based reference wind power plant project
Source: NREL

16.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; NREL 2018 ATB Spreadsheet;
BC Hydro 2013 IRP, Appendix 3A-34, pp. 2, 9
Wind levelized cost - point-of-interconnection

In its 2018 ATB Cost and Performance Summary, NREL describes the three technology advance scenarios as[1]:

- Constant: Base Year (or near-term estimates of projects under construction) equivalent through 2050 maintains current relative technology cost differences.
- Mid: technology advances through continued industry growth, public and private R&D investments, and market conditions relative to current levels that may be characterized as " likely," or " not surprising"
- Low: Technology advances that may occur with breakthroughs, increased public and private R&D investments, and/or other market conditions that lead to cost and performance levels that may be characterized as the " limit of surprise" , but not necessarily the absolute low bound.

1.16.3 Does BC Hydro consider that the mid technology advance scenario is the most appropriate scenario to estimate the cost of new generation supply in BC? If no, please explain why and which scenario is preferred.

RESPONSE:

Yes – of the three scenarios described, the mid technology advance scenario is the most appropriate. BC Hydro notes that we would use a different set of base-year technology cost assumptions than those used in the NREL ATB.

[1] https://atb.nrel.gov/electricity/2018/summary.html

16.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; NREL 2018 ATB Spreadsheet;
BC Hydro 2013 IRP, Appendix 3A-34, pp. 2, 9
Wind levelized cost - point-of-interconnection

In the NREL 2018 ATB 'land-based wind' tab, data sources for default inputs are described in Cells M770 to M784.

1.16.4 Does BC Hydro consider that the data sources used for default inputs in the NREL 2018 ATB 'land-based wind' tab are reasonable a reasonable starting point to approximate the cost of new generation supply delivered to the Lower Mainland? If no, please explain why not.

RESPONSE:

Yes. The data sources cited in the reference provide a reasonable assessment of wind energy costs for a generic US-based project; however a more reasonable assessment would seek to include the B.C.-specific cost details associated with the terrain, market conditions, soft costs etc., Please also refer to BC Hydro's response to BCUC IR 1.14.1.

16.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; NREL 2018 ATB Spreadsheet;
BC Hydro 2013 IRP, Appendix 3A-34, pp. 2, 9
Wind levelized cost - point-of-interconnection

In the NREL 2018 ATB 'land-based wind' tab, data sources for default inputs are described in Cells M770 to M784.

1.16.4 Does BC Hydro consider that the data sources used for default inputs in the NREL 2018 ATB 'land-based wind' tab are reasonable a reasonable starting point to approximate the cost of new generation supply delivered to the Lower Mainland? If no, please explain why not.

1.16.4.1 Please explain what adjustments, if any, BC Hydro considers would be appropriate to make to these estimates to approximate the plant gate cost of wind plants in BC.

RESPONSE:

It is not clear, from available documentation of the ATB database, what the initial assumptions were (e.g., with regards to soft costs, grid-specific costs or location-specific costs) to inform their cost estimate. Accordingly, BC Hydro cannot determine what incremental adjustments would be appropriate to account for the specific conditions in B.C. Please also refer to BC Hydro's response to BCUC IR 1.14.1.

16.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; NREL 2018 ATB Spreadsheet;
BC Hydro 2013 IRP, Appendix 3A-34, pp. 2, 9
Wind levelized cost - point-of-interconnection

In the NREL 2018 ATB 'land-based wind' tab, financial assumptions (2016) are described in cells S30 to S46.

1.16.5 In table form, please reproduce the NREL 2018 ATB 'land-based wind' tab financial assumptions tables, together with the model's default assumptions. In two additional columns please include the financial assumptions used in (i) the BCUC Site C Illustrative Alternative Portfolio and (ii) the assumptions BC Hydro considers would be appropriate in determining the cost of new generation supply. Where BC Hydro's proposed financial assumptions differ from that used in the BCUC Site C Illustrative Alternative Portfolio please explain why.

RESPONSE:

As requested, the NREL 2018 ATB 'land based wind' tab was used to populate the financial assumptions table. The blue fields are user inputs representing the financial assumptions requested, and the grey fields are calculations performed by the NREL ATB spreadsheet.

BC Hydro has observed that several functions within the NREL ATB spreadsheet do not work properly (e.g., "Interest Rate Nominal", "Calculated Rate of Return on Equity" or "WACC") and therefore BC Hydro does not have confidence in the spreadsheet overall. Accordingly, any conclusions based on these calculated parameters should not be relied on.

Financial Assumptions	NREL 2018 ATB	BCUC Site C Alternative Portfolio	BC Hydro assumptions
Inflation Rate	**2.5%**	**2.0%**	**2.0%**
Capital Recovery Period (Years)	**30**	**30**	**30**
Interest Rate Nominal - Mid	**3.7%**	**8.4%**	**7.0%**
Calculated Interest Rate Real - Mid	**1.2%**	**1.2%**	**1.2%**
Interest During Construction - Nominal	**3.7%**	**8.4%**	**7.0%**

Financial Assumptions	NREL 2018 ATB	BCUC Site C Alternative Portfolio	BC Hydro assumptions
Rate of Return on Equity Nominal - Mid	**9.0%**	**10.8%**	**10.1%**
Calculated Rate of Return on Equity Real - Mid	**6.4%**	**6.4%**	**6.4%**
Debt Fraction - Mid	**60.0%**	**0.0%**	**80.0%**
Tax Rate (Federal and State)	**25.7%**	**0.0%**	**0.0%**
WACC Nominal - Mid	**5.3%**	**5.3%**	**5.3%**
WACC Real - Mid	**2.7%**	**2.7%**	**2.7%**
Depreciation Period	**5**	**25**	**25**
Construction Finance Factor	**1.022**	**1.068**	**1.057**
Present Value of Depreciation	**0.868**	**0.880**	**0.880**
Project Finance Factor	**1.046**	**1.000**	**1.000**
Capital Recovery Factor (CRF) Nominal - Mid	**6.7%**	**6.7%**	**6.7%**
Capital Recovery Factor (CRF) Real - Mid	**4.9%**	**4.9%**	**4.9%**

16.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; NREL 2018 ATB Spreadsheet;
BC Hydro 2013 IRP, Appendix 3A-34, pp. 2, 9
Wind levelized cost - point-of-interconnection

In the NREL 2018 ATB 'land-based wind' tab, the levelized cost of energy ($/MWh) for TRG 4-mid is shown in cell N497 for 2018 and cell AF497 for 2036.

1.16.5.1 Please use the NREL 2018 ATB 'land-based wind' tab to calculate, in 2018 $, the 2018 and 2036 TRG 4-mid levelized cost of energy ($/MWh) under the following scenarios: (i) default financial assumptions included in the NREL model, (ii) financial assumptions used in the BCUC Site C Illustrative Alternative Portfolio, and (iii) financial assumptions as proposed by BC Hydro above.

RESPONSE:

As requested, we provide the resulting $/MWh calculation in $2018. Note that the NREL ATB 'land based wind' tab does not properly calculate the relevant financial parameters, and therefore BC Hydro does not have confidence in the $/MWh calculations. Please refer to BC Hydro's response to BCUC IR 1.16.5.

	Financial Assumptions		
TRG 4-mid levelized cost of energy in year	**NREL 2018 ATB Default ($)**	**BCUC Site C Alternative Portfolio ($)**	**BC Hydro assumptions ($)**
2018	**39/MWh**	**40/MWh**	**40/MWh**
2036	**30/MWh**	**31/MWh**	**31/MWh**

16.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; NREL 2018 ATB Spreadsheet;
BC Hydro 2013 IRP, Appendix 3A-34, pp. 2, 9
Wind levelized cost - point-of-interconnection

In the NREL 2018 ATB 'land based wind' tab, cell T20 shows that the Techno-Resource Group (TRG) 4 has a weighted average net capacity factor of 43.5%.

1.16.6 Please provide, in table and graphical form, the actual annual average US/Can $ actual exchange rate over the last 10 years, and forecast by BC Hydro until 2036. Please identify on the graph and table (i) the current US/Can $ exchange rate, and (ii) the exchange rate used in the BCUC Site C Illustrative Alternative Portfolio.

RESPONSE:

The requested tables and graphs are below.

Annual Average US/Can $ Exchange Rate by Fiscal Year

Fiscal Year	Actual (i)	Forecast (ii)	Site C (iii)	Current (iv)
F2009	**1.1274**			
F2010	**1.0904**			
F2011	**1.0163**			
F2012	**0.9930**			
F2013	**1.0012**			
F2014	**1.0537**			
F2015	**1.1391**			
F2016	**1.3121**			
F2017	**1.3125**			
F2018	**1.2833**		**1.2533**	
F2019		**1.2895**	**1.2533**	**1.3088**
F2020		**1.2642**	**1.2533**	
F2021		**1.2543**	**1.2533**	
F2022		**1.2480**	**1.2533**	

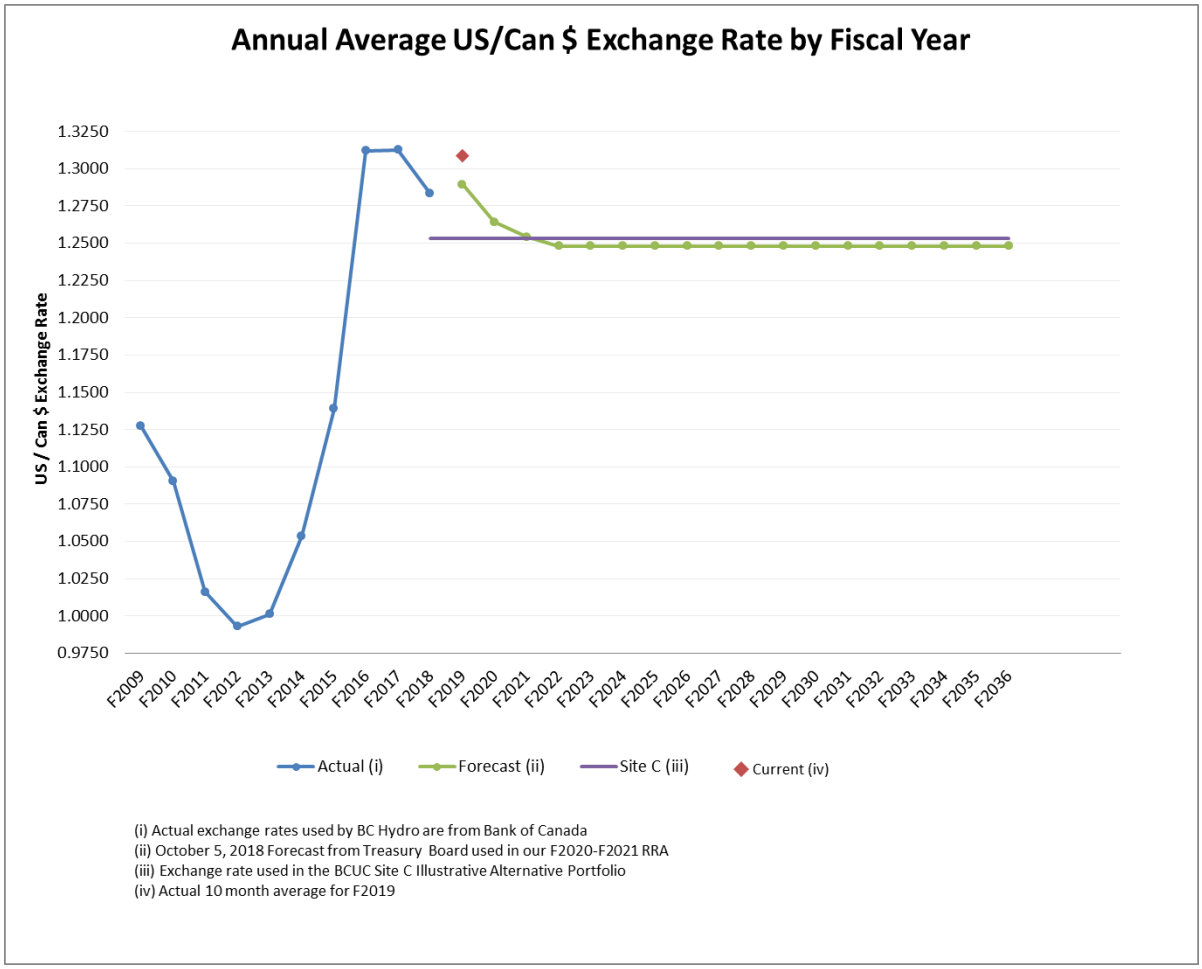
Fiscal Year	Actual (i)	Forecast (ii)	Site C (iii)	Current (iv)
F2023		**1.2480**	**1.2533**	
F2024		**1.2480**	**1.2533**	
F2025		**1.2480**	**1.2533**	
F2026		**1.2480**	**1.2533**	
F2027		**1.2480**	**1.2533**	
F2028		**1.2480**	**1.2533**	
F2029		**1.2480**	**1.2533**	
F2030		**1.2480**	**1.2533**	
F2031		**1.2480**	**1.2533**	
F2032		**1.2480**	**1.2533**	
F2033		**1.2480**	**1.2533**	
F2034		**1.2480**	**1.2533**	
F2035		**1.2480**	**1.2533**	
F2036		**1.2480**	**1.2533**	

(i) Actual exchange rates are from the Bank of Canada

(ii) October 5, 2018 Forecast from Treasury Board used in our F2020-F2021 RRA

(iii) Exchange rate used in the BCUC Site C Illustrative Alternative Portfolio

(iv) Actual 10 month average for F2019



(i) Actual exchange rates used by BC Hydro are from Bank of Canada
(ii) October 5, 2018 Forecast from Treasury Board used in our F2020-F2021 RRA
(iii) Exchange rate used in the BCUC Site C Illustrative Alternative Portfolio
(iv) Actual 10 month average for F2019

16.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; NREL 2018 ATB Spreadsheet;
BC Hydro 2013 IRP, Appendix 3A-34, pp. 2, 9
Wind levelized cost - point-of-interconnection

In the NREL 2018 ATB 'land based wind' tab, cell T20 shows that the Techno-Resource Group (TRG) 4 has a weighted average net capacity factor of 43.5%.

1.16.6.1 Please explain (i) to what extent BC Hydro considers the BC levelized cost of new wind generation would increase/decrease in proportion to changes in the US/Can exchange rate, and (ii) whether a long-term exchange rate should be used in estimating the cost of new wind generation from the NREL 2018 ATB (and if so, what rate should be assumed).

RESPONSE:

As most of the major Original Equipment Manufacturers have operations in the U.S. as well as Europe, exchange rate variations in both the U.S. dollar and the Euro can impact turbine costs and hence the levelized cost of new wind generation in Canada. However, there are also other market and financial factors, such as the strength of wind markets in the U.S./Europe, supply and demand for components in a particular construction period, interest rates and commodity prices that influence the cost of turbine components. Accordingly, BC Hydro considers there is no direct relationship between a long-term exchange rate and turbine costs and such a relationship should not be used to estimate the cost of new wind generation. There are flaws to using any one currency exchange rate when estimating future costs, but on balance, BC Hydro considers using the current exchange rate to be reasonable.

17.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; NREL 2018 ATB Spreadsheet; BC Hydro Wind Project Cost Review Final Report prepared, Hatch, May 19, 2015[1]; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 131, Appendix C, pp. 5, 7; BC Hydro 2013 IRP, Appendix 3A-34, pp. 3, 9
Wind levelized cost – Cost of incremental firm transmission (CIFT)

The NREL 2018 ATB stats in cell C99 of the Financial Definitional tab: "ATB assumes that base plant cost includes small spur line to connect with grid for all technologies in overnight capital cost. … Specific transmission lines based on geographically determined distances between [Regional Energy Deployment Systems] regions and existing transmission features for wind and solar are not included in ATB."

The BC Hydro Wind Project Cost Review Final Report prepared by Hatch (May 19, 2015) shows on page 21 (Figure 2) a regional $/MW cost comparison between regions (Vancouver Island, Peace, North Coast and Southern Interior).

The 2017 BCUC Site C Final Report (Appendix C, pp. 5, 7) assumes that wind resources are sited at the Site C location and increased wind capital and operating costs for transmission and road costs (with values derived from the project specific cost estimates from BC Hydro's resource options spreadsheet). Page 131 of 2017 BCUC Site C Final Report shows a BC Hydro estimated alternative 'block unit energy cost' (generally wind) of including a cost of incremental firm transmission (CIFT) adjustment of $2/MWh and a Cost of Required Network Upgrades of $6/MWh.

BC Hydro states in the BC Hydro 2013 IRP (Appendix 3A-34, p. 3) that CIFT adjustment was based on a BCTC Bulk Transmission System CIFT (January 2009) report which BC Hydro is in the process of updating. On page 9 of this Appendix, BC Hydro includes a CIFT adder for the PC28 wind project of $2/MWh.

1.17.1 Please confirm, or explain otherwise, that Figure 2 of the BC Hydro Wind Project Cost Review Final Report prepared by Hatch (May 19, 2015) indicates that wind cost comparisons are similar between regions.

[1] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-wind-report-20150519-hatch.pdf

RESPONSE:

Confirmed, the Hatch report shows the costs between regions are similar with some small differences. BC Hydro decided (in consultation with external stakeholders) that cost variations between regions are negligible relative to site specific conditions (e.g., terrain). Hence, BC Hydro uses B.C.-wide cost estimates with adjustments to the cost for site specific conditions.

17.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; NREL 2018 ATB Spreadsheet; BC Hydro Wind Project Cost Review Final Report prepared, Hatch, May 19, 2015[1]; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 131, Appendix C, pp. 5, 7; BC Hydro 2013 IRP, Appendix 3A-34, pp. 3, 9
Wind levelized cost – Cost of incremental firm transmission (CIFT)

The NREL 2018 ATB stats in cell C99 of the Financial Definitional tab: "ATB assumes that base plant cost includes small spur line to connect with grid for all technologies in overnight capital cost. … Specific transmission lines based on geographically determined distances between [Regional Energy Deployment Systems] regions and existing transmission features for wind and solar are not included in ATB."

The BC Hydro Wind Project Cost Review Final Report prepared by Hatch (May 19, 2015) shows on page 21 (Figure 2) a regional $/MW cost comparison between regions (Vancouver Island, Peace, North Coast and Southern Interior).

The 2017 BCUC Site C Final Report (Appendix C, pp. 5, 7) assumes that wind resources are sited at the Site C location and increased wind capital and operating costs for transmission and road costs (with values derived from the project specific cost estimates from BC Hydro's resource options spreadsheet). Page 131 of 2017 BCUC Site C Final Report shows a BC Hydro estimated alternative 'block unit energy cost' (generally wind) of including a cost of incremental firm transmission (CIFT) adjustment of $2/MWh and a Cost of Required Network Upgrades of $6/MWh.

BC Hydro states in the BC Hydro 2013 IRP (Appendix 3A-34, p. 3) that CIFT adjustment was based on a BCTC Bulk Transmission System CIFT (January 2009) report which BC Hydro is in the process of updating. On page 9 of this Appendix, BC Hydro includes a CIFT adder for the PC28 wind project of $2/MWh.

1.17.2 For the purpose of estimating BC Hydro's cost of new generation resources, please explain whether BC Hydro considers it reasonable to assume, that new wind resources are sited at the Site C location and delivered to the Lower Mainland. If no, please

[1] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-wind-report-20150519-hatch.pdf

explain which location(s) BC Hydro considers appropriate for determining the grid entry and exit point.

RESPONSE:

No, for the purpose of estimating the cost of new resources it is not reasonable to assume that new wind resources are sited at the Site C location as such an assumption underestimates the transmission and road costs. A more reasonable approach would be to assume that new generation is supplied from the lowest cost wind resources located largely in the Peace region, and include the weighted average of the transmission and road costs for those projects.

The assumption of the Lower Mainland as the exit point is appropriate because it's the load centre and is consistent with BC Hydro's approach.

17.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; NREL 2018 ATB Spreadsheet; BC Hydro Wind Project Cost Review Final Report prepared, Hatch, May 19, 2015[1]; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 131, Appendix C, pp. 5, 7; BC Hydro 2013 IRP, Appendix 3A-34, pp. 3, 9
Wind levelized cost – Cost of incremental firm transmission (CIFT)

The NREL 2018 ATB stats in cell C99 of the Financial Definitional tab: "ATB assumes that base plant cost includes small spur line to connect with grid for all technologies in overnight capital cost. … Specific transmission lines based on geographically determined distances between [Regional Energy Deployment Systems] regions and existing transmission features for wind and solar are not included in ATB."

The BC Hydro Wind Project Cost Review Final Report prepared by Hatch (May 19, 2015) shows on page 21 (Figure 2) a regional $/MW cost comparison between regions (Vancouver Island, Peace, North Coast and Southern Interior).

The 2017 BCUC Site C Final Report (Appendix C, pp. 5, 7) assumes that wind resources are sited at the Site C location and increased wind capital and operating costs for transmission and road costs (with values derived from the project specific cost estimates from BC Hydro's resource options spreadsheet). Page 131 of 2017 BCUC Site C Final Report shows a BC Hydro estimated alternative 'block unit energy cost' (generally wind) of including a cost of incremental firm transmission (CIFT) adjustment of $2/MWh and a Cost of Required Network Upgrades of $6/MWh.

BC Hydro states in the BC Hydro 2013 IRP (Appendix 3A-34, p. 3) that CIFT adjustment was based on a BCTC Bulk Transmission System CIFT (January 2009) report which BC Hydro is in the process of updating. On page 9 of this Appendix, BC Hydro includes a CIFT adder for the PC28 wind project of $2/MWh.

1.17.3 Please provide the updated CIFT report. If BC Hydro has not updated this report since 2009, please explain why.

[1] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-wind-report-20150519-hatch.pdf

RESPONSE:

BC Hydro does not have an updated CIFT report. BC Hydro has been contemplating different methodologies for estimating CIFT and plans to address this in the next IRP.

17.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; NREL 2018 ATB Spreadsheet; BC Hydro Wind Project Cost Review Final Report prepared, Hatch, May 19, 2015[1]; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 131, Appendix C, pp. 5, 7; BC Hydro 2013 IRP, Appendix 3A-34, pp. 3, 9
Wind levelized cost – Cost of incremental firm transmission (CIFT)

The NREL 2018 ATB stats in cell C99 of the Financial Definitional tab: "ATB assumes that base plant cost includes small spur line to connect with grid for all technologies in overnight capital cost. … Specific transmission lines based on geographically determined distances between [Regional Energy Deployment Systems] regions and existing transmission features for wind and solar are not included in ATB."

The BC Hydro Wind Project Cost Review Final Report prepared by Hatch (May 19, 2015) shows on page 21 (Figure 2) a regional $/MW cost comparison between regions (Vancouver Island, Peace, North Coast and Southern Interior).

The 2017 BCUC Site C Final Report (Appendix C, pp. 5, 7) assumes that wind resources are sited at the Site C location and increased wind capital and operating costs for transmission and road costs (with values derived from the project specific cost estimates from BC Hydro's resource options spreadsheet). Page 131 of 2017 BCUC Site C Final Report shows a BC Hydro estimated alternative 'block unit energy cost' (generally wind) of including a cost of incremental firm transmission (CIFT) adjustment of $2/MWh and a Cost of Required Network Upgrades of $6/MWh.

BC Hydro states in the BC Hydro 2013 IRP (Appendix 3A-34, p. 3) that CIFT adjustment was based on a BCTC Bulk Transmission System CIFT (January 2009) report which BC Hydro is in the process of updating. On page 9 of this Appendix, BC Hydro includes a CIFT adder for the PC28 wind project of $2/MWh.

1.17.3.1 Please explain what adjustment, if any, to the NREL 2018 ATB wind cost estimates BC Hydro considers appropriate to reflect CIFT costs.

[1] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-wind-report-20150519-hatch.pdf

RESPONSE:

As noted in the Guidelines for using ATB Data, "The ATB does not include impacts to the broader electric system based on output characteristics of the plant or distance from transmission infrastructure." The ATB cost estimates do not include any consideration of costs for firm bulk transmission system reinforcement.

BC Hydro has estimated CIFT based on the methodology described in the BCTC Bulk Transmission System CIFT (January 2009) report. A $2/MWh CIFT adjustment has been considered for generic wind resources located in the Peace region.

17.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; NREL 2018 ATB Spreadsheet; BC Hydro Wind Project Cost Review Final Report prepared, Hatch, May 19, 2015[1]; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 131, Appendix C, pp. 5, 7; BC Hydro 2013 IRP, Appendix 3A-34, pp. 3, 9
Wind levelized cost – Cost of incremental firm transmission (CIFT)

The NREL 2018 ATB stats in cell C99 of the Financial Definitional tab: "ATB assumes that base plant cost includes small spur line to connect with grid for all technologies in overnight capital cost. … Specific transmission lines based on geographically determined distances between [Regional Energy Deployment Systems] regions and existing transmission features for wind and solar are not included in ATB."

The BC Hydro Wind Project Cost Review Final Report prepared by Hatch (May 19, 2015) shows on page 21 (Figure 2) a regional $/MW cost comparison between regions (Vancouver Island, Peace, North Coast and Southern Interior).

The 2017 BCUC Site C Final Report (Appendix C, pp. 5, 7) assumes that wind resources are sited at the Site C location and increased wind capital and operating costs for transmission and road costs (with values derived from the project specific cost estimates from BC Hydro's resource options spreadsheet). Page 131 of 2017 BCUC Site C Final Report shows a BC Hydro estimated alternative 'block unit energy cost' (generally wind) of including a cost of incremental firm transmission (CIFT) adjustment of $2/MWh and a Cost of Required Network Upgrades of $6/MWh.

BC Hydro states in the BC Hydro 2013 IRP (Appendix 3A-34, p. 3) that CIFT adjustment was based on a BCTC Bulk Transmission System CIFT (January 2009) report which BC Hydro is in the process of updating. On page 9 of this Appendix, BC Hydro includes a CIFT adder for the PC28 wind project of $2/MWh.

1.17.4 For the purpose of estimating BC Hydro's cost of new generation resources, please explain whether it is necessary to include an adjustment for the Cost of Required Network Upgrade in addition to a CIFT adjustment. If yes, please explain why only one adjustment was made in the 2013 IRP.

[1] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-wind-report-20150519-hatch.pdf

RESPONSE:

CIFT provides an indicative cost allowance for bulk path reinforcement between regions, and Network Upgrade costs provide an indicative cost allowance for interconnecting resources to the bulk transmission system.

Both CIFT and Network Upgrade costs need to be accounted for to reflect the total cost of delivering the energy from the new generation resources to the load center (i.e., Lower Mainland).

Network Upgrade costs were included in the portfolio analysis underpinning the 2013 IRP even though it was not included in the numbers presented in Table 2 of Appendix 3A-34 in the 2013 IRP. Also see section 6.2 of Appendix 3A-1 of the 2013 IRP that explains why these numbers did not include Network Upgrade costs.

17.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; NREL 2018 ATB Spreadsheet; BC Hydro Wind Project Cost Review Final Report prepared, Hatch, May 19, 2015[1]; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 131, Appendix C, pp. 5, 7; BC Hydro 2013 IRP, Appendix 3A-34, pp. 3, 9
Wind levelized cost – Cost of incremental firm transmission (CIFT)

The NREL 2018 ATB stats in cell C99 of the Financial Definitional tab: "ATB assumes that base plant cost includes small spur line to connect with grid for all technologies in overnight capital cost. … Specific transmission lines based on geographically determined distances between [Regional Energy Deployment Systems] regions and existing transmission features for wind and solar are not included in ATB."

The BC Hydro Wind Project Cost Review Final Report prepared by Hatch (May 19, 2015) shows on page 21 (Figure 2) a regional $/MW cost comparison between regions (Vancouver Island, Peace, North Coast and Southern Interior).

The 2017 BCUC Site C Final Report (Appendix C, pp. 5, 7) assumes that wind resources are sited at the Site C location and increased wind capital and operating costs for transmission and road costs (with values derived from the project specific cost estimates from BC Hydro's resource options spreadsheet). Page 131 of 2017 BCUC Site C Final Report shows a BC Hydro estimated alternative 'block unit energy cost' (generally wind) of including a cost of incremental firm transmission (CIFT) adjustment of $2/MWh and a Cost of Required Network Upgrades of $6/MWh.

BC Hydro states in the BC Hydro 2013 IRP (Appendix 3A-34, p. 3) that CIFT adjustment was based on a BCTC Bulk Transmission System CIFT (January 2009) report which BC Hydro is in the process of updating. On page 9 of this Appendix, BC Hydro includes a CIFT adder for the PC28 wind project of $2/MWh.

1.17.5 Please explain how BC Hydro quantifies and allocates incremental transmission costs under the Standard Offer Program.

[1] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-wind-report-20150519-hatch.pdf

RESPONSE:

As provided in Phase 1 of the Government's Comprehensive Review, on February 14, 2019, the Standing Offer Program is indefinitely suspended, except for the five First Nations projects that BC Hydro committed to in March 2018.

The Standing Offer Program price was based on the results of BC Hydro's most recent broad-based competitive call process, which was the Clean Power Call initiated in June 2008. Regional prices were derived from successful Clean Power Call bids and were adjusted to account for transmission and losses to an IPP's point of interconnection. These regional prices were as set out in the Standing Offer Program Rules.

18.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 5, 12, 20, 31; BC Hydro 2013 IRP, Appendix 3A-34, pp. 3, 9
Wind levelized cost – line losses

BC Hydro states on page 3 of Appendix 3A-34 in the BC Hydro 2013 IRP that the losses were calculated based on a BCTC report titled: Peak Load Incremental Losses for the Bulk Transmission System (January 2010). Page 9 of the same Appendix shows a line losses adder of $11/MWh for PC28 wind resource.

1.18.1 Please provide an updated Peak Load Incremental Losses for the Bulk Transmission System. If BC Hydro has not updated these reports since 2009, please explain whether the results from the 2009 report are still reliable.

RESPONSE:

BC Hydro has updated Peak Load Incremental Losses (PLIL %) for the Bulk Transmission System in 2018, as presented in the table below.

Region		2018 update	2010 version
Peace River	**PR**	**19.82**	**14.00**
North Coast	**NC**	**11.55**	**8.77**
Central Interior	**CI**	**12.21**	**8.92**
Kelly Nicola	**KLY/NIC**	**6.22**	**5.17**
Lower Mainland	**LM**	**-**	**-**
Vancouver Island	**VI**	**(0.62)**	**(0.65)**
Selkirk	**SI**	**9.04**	**9.42**
Revelstoke / Ashton Creek	**SI**	**9.04**	**9.42**
East Kootenay	**EK**	**7.24**	**9.72**
Mica	**MCA**	**11.35**	**9.85**

18.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 5, 12, 20, 31; BC Hydro 2013 IRP, Appendix 3A-34, pp. 3, 9
Wind levelized cost – line losses

BC Hydro states on page 3 of Appendix 3A-34 in the BC Hydro 2013 IRP that the losses were calculated based on a BCTC report titled: Peak Load Incremental Losses for the Bulk Transmission System (January 2010). Page 9 of the same Appendix shows a line losses adder of $11/MWh for PC28 wind resource.

1.18.1.1 Please describe the general methodology used to calculate the line losses adjustment in the 2013 IRP, including whether they were based on average or incremental line losses.

RESPONSE:

The methodology used to calculate the line losses adjustment in the 2013 IRP was based on incremental line losses. The BCTC methodology computes Peak Load Incremental Losses (PLIL) across BC Hydro's bulk transmission paths, based on a simulation of peak hour power flows from a specific new generator to a fictitious incremental load across the BC Hydro system. After simulation, the difference between the generator's MW output and the MW of load served is attributed to the incremental peak hour losses along the transmission path.

Line losses adjustment depends on the location and generation characteristics. The line losses adjustment of $11/MWh for PC28 wind resource was calculated in the following four steps:

1. **Calculate the total incremental losses from the Peace River region to the Lower Mainland as 14 per cent (the sum of 5.08 per cent from Peace River to Central Interior, 3.98 per cent from Central Interior to Kelly Lake, and 4.94 per cent from Kelly Lake to Lower Mainland);**

2. **Convert to energy losses using the average load factor of 0.65715 and loss load factor of 0.47575 for year 2014/2015 as total incremental losses * installed capacity * 8760 * loss load factor * generation capacity factor / average load factor;**

3. **Calculate the UEC after energy loss as UEC_POI * 1.05 * average energy / (average energy - energy losses); and**

4. Calculate the line losses adder as the difference between UEC_POI * 1.05 and the UEC after energy loss.

Combing the four steps,
the line losses adjustment = UEC_POI * 1.05 * (1/(1 - total incremental losses * loss load factor / average load factor) - 1).

For the example PC28 wind,
the line losses adjuster= 90 * 1.05 * (1/(1-0.14 * 0.47575/0.65715) - 1) = $11/MWh.

18.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 5, 12, 20, 31; BC Hydro 2013 IRP, Appendix 3A-34, pp. 3, 9
Wind levelized cost – line losses

BC Hydro states on page 3 of Appendix 3A-34 in the BC Hydro 2013 IRP that the losses were calculated based on a BCTC report titled: Peak Load Incremental Losses for the Bulk Transmission System (January 2010). Page 9 of the same Appendix shows a line losses adder of $11/MWh for PC28 wind resource.

1.18.2 Please estimate annual (i) average and (ii) marginal annual transmission losses from the Site C location to the Lower Mainland. Please explain whether BC Hydro considers it appropriate to use average or marginal transmission losses in evaluating the benefit of a generation facility located close to the load.

RESPONSE:

Based on the methodology described in the BCTC's January 2010 report, for a project from the Site C location, i.e., Peace River, the marginal (or incremental) losses to the Lower Mainland are 14 per cent (the sum of 5.08 per cent from Peace River to Central Interior, 3.98 per cent from Central Interior to Kelly Nicola, and 4.94 per cent from Kelly Nicola to Lower Mainland), and the annual average losses are about 6.66 per cent using the Loss Load Factor (LLF) of 0.47575. Please also refer to BC Hydro's response to BCUC IR 1.18.1.1.

When a generation facility is located close to the load (e.g., within the Lower Mainland), both marginal and average losses will be negligible due to shorter transmission circuit(s).

18.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 5, 12, 20, 31; BC Hydro 2013 IRP, Appendix 3A-34, pp. 3, 9
Wind levelized cost – line losses

BC Hydro states on page 3 of Appendix 3A-34 in the BC Hydro 2013 IRP that the losses were calculated based on a BCTC report titled: Peak Load Incremental Losses for the Bulk Transmission System (January 2010). Page 9 of the same Appendix shows a line losses adder of $11/MWh for PC28 wind resource.

1.18.3 Please explain how BC Hydro quantifies and allocates line losses under the Standard Offer Program.

RESPONSE:

Please refer to BC Hydro response to BCUC IR 1.17.5.

19.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; BC Hydro 2013 IRP, Appendix 3A-34, p. 9; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, Appendix A, pp. 24, 25, 28; Appendix C, p. 5
Wind levelized cost – integration cost

BC Hydro includes on page 9 in the BC Hydro 2013 IRP a wind integration cost adder of $10/MWh.

Page 5 of Appendix C in the 2017 BCUC Site C Final Report states:

> It is assumed that BC Hydro has sufficient wind integration ability as a result of its existing hydro assets to integrate the wind included in the Alternative Portfolio. The cost of wind integration is therefore assumed to reflect an incremental reduction in the potential of BC Hydro to export its wind integration services into neighbouring markets.
>
> Assumed wind integration costs resulting from the Alternative Portfolio have been reduced to $1/MWh, taking into account concerns raised with BC Hydro's $5/MWh estimate.

The 2017 BCUC Site C Final Report also states in Appendix A, pages 24 and 25, "BC Hydro stated: … the 2016 Wind Integration Study is expected to be available for BC Hydro's next Integrated Resource Plan, scheduled for November 2018", and notes that PacifiCorp's 2017 IRP wind integration cost estimate was US $0.57/MWh.

The 2017 BCUC Site C Final Report further states on page 28 of Appendix A, "BC Hydro stated … that Powerex's level of participation in the [Western Energy Imbalance Market (EIM)] will not frequently be limited by the capacity or flexibility of the BC Hydro system, but rather by the level of market opportunities and the transmission transfer capability in the EIM."

1.19.1 Please provide BC Hydro's updated Wind Integration Study, or if not available, please provide an update on its progress (including a timeline of stakeholder consultation).

RESPONSE:

An updated Wind Integration Study is not yet available. As described in BC Hydro's response to BCUC IR 3.21.0 for the Site C Inquiry, the work plan for the study consists of three major components:

1) **Determine the operating capacity reserves (within hour and hour-to-hour);**

2) **Determine the day-ahead capacity reserves; and**

3) **Conduct system modelling to calculate the costs associated with the operating and day-ahead capacity reserves.**

To date, the first component as well as the pre-work for components 2 and 3 above (such as establishing and finalizing inputs and modelling assumptions, conducting model test runs) have been completed. We plan to have an updated study available for the next IRP. At this time, we have not outlined any stakeholder consultation and associated timeline.

19.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; BC Hydro 2013 IRP, Appendix 3A-34, p. 9; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, Appendix A, pp. 24, 25, 28; Appendix C, p. 5
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The 2017 BCUC Site C Final Report further states on page 28 of Appendix A, "BC Hydro stated … that Powerex's level of participation in the [Western Energy Imbalance Market (EIM)] will not frequently be limited by the capacity or flexibility of the BC Hydro system, but rather by the level of market opportunities and the transmission transfer capability in the EIM."

1.19.2 For the purpose of estimating BC Hydro's cost of new generation resources, please comment on whether BC Hydro considers a wind integration cost (for marginal wind additions) of $1/MWh to be reasonable? Please explain why or why not.

RESPONSE:

As noted in BC Hydro's response to BCUC IR 1.19.1 an updated Wind Integration Study is not yet available. Among other things, the Wind Integration Study will evaluate wind integration capabilities and costs, determining whether $1/MWh is reasonable.

BC Hydro's notes that its last study in 2010 estimated a wind integration cost of $10/MWh with a range from $5 to $15/MWh. BC Hydro recognizes that since that last study was completed, there have been some factors that have had a downward effect on the wind integration cost. However, BC Hydro is also aware of a rapid growth in the demand for capacity and flexibility in the Western Interconnect that will have an upward effect on the wind integration cost. The fundamentals driving this growth are the retirement of thermal resources that have historically provided capacity and flexibility, and the continued installation of wind and solar resources. In the $104/MWh LRMC used in the Application, the lower end of the range from the last study (i.e., $5/MWh) was assumed.

19.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; BC Hydro 2013 IRP, Appendix 3A-34, p. 9; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, Appendix A, pp. 24, 25, 28; Appendix C, p. 5
Wind levelized cost – integration cost

BC Hydro includes on page 9 in the BC Hydro 2013 IRP a wind integration cost adder of $10/MWh.

Page 5 of Appendix C in the 2017 BCUC Site C Final Report states:

> It is assumed that BC Hydro has sufficient wind integration ability as a result of its existing hydro assets to integrate the wind included in the Alternative Portfolio. The cost of wind integration is therefore assumed to reflect an incremental reduction in the potential of BC Hydro to export its wind integration services into neighbouring markets.
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> Assumed wind integration costs resulting from the Alternative Portfolio have been reduced to $1/MWh, taking into account concerns raised with BC Hydro's $5/MWh estimate.

The 2017 BCUC Site C Final Report also states in Appendix A, pages 24 and 25, "BC Hydro stated: … the 2016 Wind Integration Study is expected to be available for BC Hydro's next Integrated Resource Plan, scheduled for November 2018", and notes that PacifiCorp's 2017 IRP wind integration cost estimate was US $0.57/MWh.

The 2017 BCUC Site C Final Report further states on page 28 of Appendix A, "BC Hydro stated … that Powerex's level of participation in the [Western Energy Imbalance Market (EIM)] will not frequently be limited by the capacity or flexibility of the BC Hydro system, but rather by the level of market opportunities and the transmission transfer capability in the EIM."

1.19.3 Please explain whether Powerex/BC Hydro sales in the EIM could reduce opportunities to sell in the energy market (for example, as a result of transmission constraints).

RESPONSE:

Powerex's participation in the EIM, which is a voluntary energy market, does not reduce opportunities to sell energy, nor does it limit Powerex's ability to choose into which energy market to sell energy.

19.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; BC Hydro 2013 IRP, Appendix 3A-34, p. 9; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, Appendix A, pp. 24, 25, 28; Appendix C, p. 5
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> It is assumed that BC Hydro has sufficient wind integration ability as a result of its existing hydro assets to integrate the wind included in the Alternative Portfolio. The cost of wind integration is therefore assumed to reflect an incremental reduction in the potential of BC Hydro to export its wind integration services into neighbouring markets.
>
> Assumed wind integration costs resulting from the Alternative Portfolio have been reduced to $1/MWh, taking into account concerns raised with BC Hydro's $5/MWh estimate.

The 2017 BCUC Site C Final Report also states in Appendix A, pages 24 and 25, "BC Hydro stated: … the 2016 Wind Integration Study is expected to be available for BC Hydro's next Integrated Resource Plan, scheduled for November 2018", and notes that PacifiCorp's 2017 IRP wind integration cost estimate was US $0.57/MWh.

The 2017 BCUC Site C Final Report further states on page 28 of Appendix A, "BC Hydro stated … that Powerex's level of participation in the [Western Energy Imbalance Market (EIM)] will not frequently be limited by the capacity or flexibility of the BC Hydro system, but rather by the level of market opportunities and the transmission transfer capability in the EIM."

1.19.4 By what year does BC Hydro consider that Powerex sales into the EIM will be limited by the flexibility of the BC Hydro system? Please explain.

RESPONSE:

BC Hydro has made no such forecast with respect to Powerex's voluntary participation in the EIM.

20.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; BC Hydro 2013 IRP, Appendix 3A-34, pp. 3, 9–15; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, Appendix C, pp. 3–5
Wind levelized cost – capacity benefit

Page 3 in Appendix 3A-34 of the BC Hydro 2013 IRP states that a capacity credit of $50/kW-year was applied to resource options capable of delivering an hourly firm product. Pages 9 to 15 of the Appendix show that BC Hydro did not apply a capacity credit to wind resources.

Page 3 to 4 in Appendix C of the 2017 BCUC Site C Final Report states: "In any year, if the capacity of the Alternative Portfolio exceeds that of the gap to fill and is used to meet BC Hydro's domestic load requirements, the Alternative Portfolio will be credited with the assumed value of this additional capacity at $50/kW-year" and that capacity surplus to BC Hydro's requirements is assumed to have no additional value. Page 5 of the Appendix also states that, for wind projects, effective load carrying capacity for each project was taken from BC Hydro's resource options spreadsheet.

1.20.1 Please explain whether BC Hydro considers wind projects generally provide a capacity benefit, and if so how much.

RESPONSE:

A wind project on its own does not provide dependable capacity. Accordingly, wind projects are therefore not eligible for a capacity credit when calculating adjusted unit energy cost. However, on a portfolio basis, BC Hydro recognizes the benefits of aggregating wind resources with system capacity using Effective Load Carrying Capability (ELCC). A portfolio with aggregated wind resources is credited for this ELCC based on the cost of capacity deferred.

20.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; BC Hydro 2013 IRP, Appendix 3A-34, pp. 3, 9–15; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, Appendix C, pp. 3–5
Wind levelized cost – capacity benefit

Page 3 in Appendix 3A-34 of the BC Hydro 2013 IRP states that a capacity credit of $50/kW-year was applied to resource options capable of delivering an hourly firm product. Pages 9 to 15 of the Appendix show that BC Hydro did not apply a capacity credit to wind resources.

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1.20.2 For the purpose of estimating BC Hydro's $/MWh cost of a new generation resources, please comment on whether BC Hydro considers that BCUC Site C Illustrative Portfolio assumptions regarding the valuation of capacity benefits ($0/MWh when BC Hydro is in a surplus capacity situation, $50/MWh when BC Hydro has a capacity shortage) is reasonable? Please explain why/why not (and if not, please provide and support alternative valuations).

RESPONSE:

Generally, BC Hydro considers a value of $0/kw-yr as reasonable for surplus capacity value. However, we do not consider $50/MWh as reasonable, for assessing the value of capacity benefits in a portfolio during a period of capacity shortfall. BC Hydro assigns different capacity credits based on their contribution in meeting the system resource adequacy (i.e., system peak) requirement. During system surplus there is no additional value, while during system deficit the value is provided in Table 3-11 of Appendix B to the Application.

21.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; BC Hydro 2013 IRP, Appendix 3A-34, pp. 2, 3; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 93; Exhibit F1-4, BCUC 2.0, Attachment 1
Wind levelized cost – shape adjustment

BC Hydro states in the BC Hydro 2013 IRP that the amount of firm energy from a resource option during the freshet (May through July) was limited to 25 per cent of the total firm energy for the year. Any excess energy was deemed to be non-firm. The non-firm energy was valued at the market price. In valuing energy a 3 x 12 time of delivery factor was used which was the same as that used in the Clean Power Call.

In Exhibit F1-4 in the Site C Inquiry BC Hydro provided an Excel file (AdjUEC (BCUC Request)) which adjusted the wind value for the energy shape (calculations tab). The 'resource options' and 'Tables of Constants' tab showed the inputs. The Site C Inquiry Final Report page 93, included a chart provided by BC Hydro which compares average peak, off-peak and all hours prices by years.

1.21.1 Please provide in table and graphical form (i) the $/MWh market price assumption for Market Scenario 1 used in the 2013 BCH IRP (for each year to F2036), and (ii) the $/MWh market price assumption (over the same period) used by BC Hydro in the most recent revenue requirement application.

RESPONSE:

This response and the attachment have been redacted. The redacted information is proprietary to a third-party, and public disclosure of this information would be harmful to the commercial interests of the third-party.

Please refer to the tab "BCUC_1.21.1" of the attached spreadsheet that provides the information requested.

BC Hydro has provided a description of the current price forecast and the forecast methodology in the response to CEC IR 1.4.3. The following section describes analysis that BC Hydro has carried out in comparing the current forecast to other forecasts and market forwards.

Figure 1 below shows a comparison of the ABB Fall 2017 forecast against the ABB Spring 2016 reference case, BC Hydro 2013 IRP Scenario 1, other analyst

forecasts and the latest market forwards. The fall 2017 forecast has dropped relative to the spring 2016 reference case due to a combination of lower gas prices, increasing renewable penetration, and a reduction in demand growth expectations.

Figure 1 above: ABB Fall 2017 Reference Case Mid-C annual average price (including low-high uncertainty range) as compared to ABB Spring 2016 Reference Case, BC Hydro IRP Scenario 1, other analyst forecasts and latest market forwards.

Figure 2 shows the historic Mid-C prices relative to the ABB Fall 2017 forecast. When comparing electricity market price forecasts to historic prices it is important to consider natural gas prices. Natural gas has been, and continues to be, a major driver for electricity market prices in the Western Interconnect. The historic Mid-C price reflects the large drop in natural gas prices post 2008.

Figure 2 ABB Mid-C price forecast relative to historic prices and market forwards

CONFIDENTIAL ATTACHMENT

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21.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; BC Hydro 2013 IRP, Appendix 3A-34, pp. 2, 3; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 93; Exhibit F1-4, BCUC 2.0, Attachment 1
Wind levelized cost – shape adjustment

BC Hydro states in the BC Hydro 2013 IRP that the amount of firm energy from a resource option during the freshet (May through July) was limited to 25 per cent of the total firm energy for the year. Any excess energy was deemed to be non-firm. The non-firm energy was valued at the market price. In valuing energy a 3 x 12 time of delivery factor was used which was the same as that used in the Clean Power Call.

In Exhibit F1-4 in the Site C Inquiry BC Hydro provided an Excel file (AdjUEC (BCUC Request)) which adjusted the wind value for the energy shape (calculations tab). The 'resource options' and 'Tables of Constants' tab showed the inputs. The Site C Inquiry Final Report page 93, included a chart provided by BC Hydro which compares average peak, off-peak and all hours prices by years.

1.21.2 Please explain how the '3 x 12 Time of Delivery Price Adjustment' factors were arrived at, whether it was used to value firm and non-firm energy, and when this data was last updated.

RESPONSE:

The "3 x 12 Time of Delivery Price Adjustment" factors account for the value of energy delivered to BC Hydro at different hours in a day and in different months in the year. It is derived by evaluating the market electricity prices during the peak, super peak, and off peak hours of each month, and expressing the prices during those hours as a ratio of the average annual market price.

It was used to value both firm and non-firm energy.

The Delivery Price Adjustment Table used in this application is the same as the table used in the 2013 IRP.

21.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; BC Hydro 2013 IRP, Appendix 3A-34, pp. 2, 3; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 93; Exhibit F1-4, BCUC 2.0, Attachment 1
Wind levelized cost – shape adjustment

BC Hydro states in the BC Hydro 2013 IRP that the amount of firm energy from a resource option during the freshet (May through July) was limited to 25 per cent of the total firm energy for the year. Any excess energy was deemed to be non-firm. The non-firm energy was valued at the market price. In valuing energy a 3 x 12 time of delivery factor was used which was the same as that used in the Clean Power Call.

In Exhibit F1-4 in the Site C Inquiry BC Hydro provided an Excel file (AdjUEC (BCUC Request)) which adjusted the wind value for the energy shape (calculations tab). The 'resource options' and 'Tables of Constants' tab showed the inputs. The Site C Inquiry Final Report page 93, included a chart provided by BC Hydro which compares average peak, off-peak and all hours prices by years.

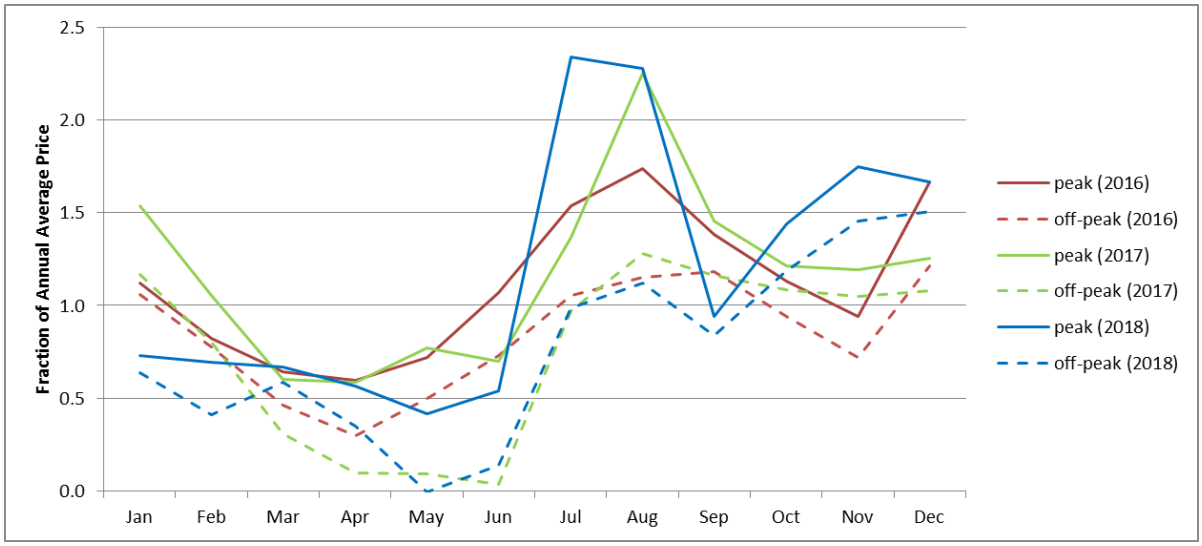
1.21.3 Please provide an updated '3 x 12 Time of Delivery Price Adjustment' factors table which uses as its source for the weightings the average monthly peak, super-peak and off-peak Mid-C prices for the last three years. Please explain all assumptions used, and also provide the average data for a different time period (such as the average for the last two or five years) if BC Hydro considers that to be more appropriate for resource planning.

RESPONSE:

Reliable historical Mid-C prices at an hourly resolution are not readily available thus precluding the creation of an accurate historical 3 x 12 Time of Delivery Price Adjustment factors table.

The following figure is provided as an alternative and illustrates monthly average factors for peak and off-peak periods for each of the past 3 calendar years. These factors were calculated by taking the monthly average peak and off-peak prices and dividing them by the annual average price. As shown, there is substantial variability in the monthly factors from one year to the next driven by conditions specific to that year. As an example, both the on-peak and off-peak values in November and December 2018 are much higher than corresponding values for

2016 and 2017 due to higher market electricity prices resulting from the Enbridge pipeline outage and low water conditions in the Pacific Northwest.



BC Hydro does not consider a 3 X 12 Time of Delivery Price Adjustment with weightings based on historical market prices to be appropriate for long term planning because (1) the recent historical market prices will be biased by short-term phenomenon such as water conditions or disruptions in gas supplies; and (2) longer term historical market prices are biased by market conditions from many years ago which may have no relevance to current market conditions e.g., impact from shale gas technologies on the market price. To evaluate long-term contracts, BC Hydro believes a weighting table based on long-term forecasts is more appropriate because it attempts to incorporate long-term market trends without being overly influenced by temporary phenomenon.

21.0 B. ECONOMIC ANALYSIS

Reference: COST OF NEW GENERATION SUPPLY
Exhibit B-1, pp. 12, 20, 31; BC Hydro 2013 IRP, Appendix 3A-34, pp. 2, 3; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 93; Exhibit F1-4, BCUC 2.0, Attachment 1
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In Exhibit F1-4 in the Site C Inquiry BC Hydro provided an Excel file (AdjUEC (BCUC Request)) which adjusted the wind value for the energy shape (calculations tab). The 'resource options' and 'Tables of Constants' tab showed the inputs. The Site C Inquiry Final Report page 93, included a chart provided by BC Hydro which compares average peak, off-peak and all hours prices by years.

1.21.4 Please provide the AdjUEC (BCUC Request) spreadsheet provided in the Site C Inquiry. Please update this spreadsheet to allow calculation of an additional resource option ('average wind') which reflects the weighted average (by average annual energy) of the wind options included in the resource options tab.

RESPONSE:

Please refer to the attached spreadsheet.

BC Hydro
Power smart

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

22.0 B. ECONOMIC ANALYSIS

Reference: ECONOMIC EVALUATION
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, Appendix C, p. 2
Discount rate

The 2017 BCUC Site C Inquiry Final Report states in Appendix C, page 2: "The discount rate proposed by BC Hydro for Site C (6% nominal, 3.9% real) has been assumed."

1.22.1 Does BC Hydro consider a discount rate of 6% nominal, 3.9% real is appropriate for an economic evaluation of EPA renewals? Please explain.

RESPONSE:

Yes. The discount rate used to present value a series of cash flows, evaluate business cases, and to support investment decisions at BC Hydro (e.g., capital projects and EPA renewals) is based on BC Hydro's weighted average cost of capital (WACC). A discount rate of 6 per cent nominal and 3.9 per cent real is appropriate as this aligns with BC Hydro's WACC at the time of filing this Application (and currently). As stated in section 4.1.2 of the Waneta 2017 Transaction Application (Exhibit B-1), the 6 per cent nominal discount rate was derived using the WACC methodology that BC Hydro has employed since 2008.

23.0 B. ECONOMIC ANALYSIS

Reference: ECONOMIC EVALUATION
Exhibit B-1, pp. 12, 20, 31
Wealth transfers

1.23.1 Does BC Hydro consider that in a public interest analysis water rentals should be excluded (for example, on the basis that they are a wealth transfer) or included (for example, on the basis that they are a proxy for environmental costs)? Please explain.

RESPONSE:

IPP costs, such as water rental and taxes, are part of an IPP's cost of doing business. Given that BC Hydro negotiated EPA renewal pricing that is reflective of the IPP cost of service, these IPP costs are reflected in the EPA price and thus, the cost-effective analysis. These IPP costs are otherwise not part of BC Hydro's analysis for the purposes of a section 71 filing.

23.0 B. ECONOMIC ANALYSIS

Reference: ECONOMIC EVALUATION
Exhibit B-1, pp. 12, 20, 31
Wealth transfers

1.23.2 Does BC Hydro consider that the cost of taxes (such as property taxes) should be excluded from the public interest analysis (please explain why/why not).

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.23.1.

23.0 B. ECONOMIC ANALYSIS

Reference: ECONOMIC EVALUATION
Exhibit B-1, pp. 12, 20, 31
Wealth transfers

1.23.2.1 Please estimate property taxes (in $/MWh) that would be paid by a wind farm

RESPONSE:

Property taxes for wind farms are dependent on the municipal tax rate and the property assessment value (as calculated by the B.C. Assessment Office), and hence vary by location, land value, size of the wind farm, improvement valuation and depreciation. Please also refer to the Hatch Wind Project Cost Review for BC Update (Final Report dated May 19, 2015)[1] where an annual property tax estimate of $8,333/MW was provided for wind projects in B.C.

[1] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-wind-report-20150519-hatch.pdf

24.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 152; Appendix C, pp. 3, 6 Mid-C forecast data

The BCUC Site C Inquiry Final Report, page 152, includes BC Hydro's F2017-F2019 Revenue Requirement Application (RRA) Mid-C Forecast. Appendix C in the BCUC Site C Inquiry states on page 6 that Illustrative Alternative Portfolio exchange rate was assumed to be $1 CAD = $0.7979 USD and on page 3 that the value of energy surplus to BC Hydro's requirement is based on:

- a Mid-C market price forecast between the BC Hydro proposed Mid-C market price and ABB's bottom forecast range.[950] Approximately, the Mid-C market price rises each year by CAD $1/MWh in real terms starting with a Mid-C market price at real F2018 CAD $32/MWh in 2018 with real escalations to real F2018 CAD $55/MWh in 2040,
- less losses (1.9%) and wheeling costs ($6.3/MWh) to the US/Canada border;[951] and
- less 11% incremental transmission losses to Site C plant gate location.[952]

The underlying data is included in the 'Sensitivity Data' tab.

1.24.1 Please reproduce, in a table and working excel spreadsheet, BC Hydro's F2017-F2019 Mid-C Forecast as provided on page 152 of the BCUC Site C Inquiry Final Report.

RESPONSE:

Please refer to the tab "BCUC_1.24.1, 1.24.1.2" in the attached spreadsheet in BC Hydro's response to BCUC IR 1.21.1.

24.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 152; Appendix C, pp. 3, 6
Mid-C forecast data

The BCUC Site C Inquiry Final Report, page 152, includes BC Hydro's F2017-F2019 Revenue Requirement Application (RRA) Mid-C Forecast. Appendix C in the BCUC Site C Inquiry states on page 6 that Illustrative Alternative Portfolio exchange rate was assumed to be $1 CAD = $0.7979 USD and on page 3 that the value of energy surplus to BC Hydro's requirement is based on:

- a Mid-C market price forecast between the BC Hydro proposed Mid-C market price and ABB's bottom forecast range.[950] Approximately, the Mid-C market price rises each year by CAD $1/MWh in real terms starting with a Mid-C market price at real F2018 CAD $32/MWh in 2018 with real escalations to real F2018 CAD $55/MWh in 2040,
- less losses (1.9%) and wheeling costs ($6.3/MWh) to the US/Canada border;[951] and
- less 11% incremental transmission losses to Site C plant gate location.[952]

The underlying data is included in the 'Sensitivity Data' tab.

1.24.1.1 Please provide a similar table and working excel spreadsheet (i.e. for 2016 to 2033) which starts with the Site C Panel market price forecast at the Site C plant gate location used in the Illustrative Alternative Portfolio, and then identifies (using the assumption in Appendix C of the Site C Final Report), the sell price at the BC border (in Can $) and the Mid-C price forecast at the Mid-C location (in US $). Please show the assumptions made at each step.

RESPONSE:

Please refer to the tab "BCUC_1.24.1.1" in the attached spreadsheet in BC Hydro's response to BCUC IR 1.21.1.

BC Hydro notes that the information provided covers the period fiscal 2019 to fiscal 2041.

24.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 152; Appendix C, pp. 3, 6
Mid-C forecast data

The BCUC Site C Inquiry Final Report, page 152, includes BC Hydro's F2017-F2019 Revenue Requirement Application (RRA) Mid-C Forecast. Appendix C in the BCUC Site C Inquiry states on page 6 that Illustrative Alternative Portfolio exchange rate was assumed to be $1 CAD = $0.7979 USD and on page 3 that the value of energy surplus to BC Hydro's requirement is based on:

- a Mid-C market price forecast between the BC Hydro proposed Mid-C market price and ABB's bottom forecast range.[950] Approximately, the Mid-C market price rises each year by CAD $1/MWh in real terms starting with a Mid-C market price at real F2018 CAD $32/MWh in 2018 with real escalations to real F2018 CAD $55/MWh in 2040,
- less losses (1.9%) and wheeling costs ($6.3/MWh) to the US/Canada border;[951] and
- less 11% incremental transmission losses to Site C plant gate location.[952]

The underlying data is included in the 'Sensitivity Data' tab.

1.24.1.2 Please provide (in graphical and table form) a comparison of (i) the Mid-C price Can $ forecast at the Lower Mainland location, and (i) the Mid-C US $ price at the Mid-C location, which compares BC Hydro's F2017-2019 RRA forecast with the Site C Panel forecast used in the Illustrative Alternative Portfolio.

RESPONSE:

Please refer to the tab "BCUC_1.24.1, 1.24.1.2" in the attached spreadsheet in BC Hydro's response to BCUC IR 1.21.1. In this response we have assumed the market price at the Lower Mainland is equivalent to the B.C. Border sell price because BC Hydro's loss factor from the Lower Mainland to the B.C. Border is zero.

25.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, pp. 88, 91
ABB forecast update

The BCUC Site C Inquiry Final Report includes on page 88 a graphical comparison of Site C Energy Cost to Mid-C market electricity price, and on page 91 a Mid-C average price forecast comparison.

1.25.1 Please provide, in a table and working excel spreadsheet, an update to BC Hydro's F2017-F2019 Mid-C Forecast as provided on page 152 of the BCUC Site C Inquiry Final Report using the most recent ABB forecast and the exchange rate BC Hydro considers appropriate for long-term resource planning. Please provide all assumptions used (including the date of the most recent ABB forecast and support for the exchange rate assumption) and provide data for all years included in the ABB forecast.

RESPONSE:

For a description of the current forecast and exchange rate assumptions please refer to BC Hydro's response to CEC IR 1.4.3. The requested tables are provided in the tab "BCUC_1.25.1" in the attached spreadsheet to BCUC IR 1.21.1.

25.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, pp. 88, 91
ABB forecast update

The BCUC Site C Inquiry Final Report includes on page 88 a graphical comparison of Site C Energy Cost to Mid-C market electricity price, and on page 91 a Mid-C average price forecast comparison.

1.25.2 Please update the graph on page 88 of Site C Inquiry Final Report for the most recent ABB forecast and state the currency denomination and location. Please exclude reference to Site C costs from the chart, and include in an excel spreadsheet the data for the Mid-C electricity price forecast and the high/low points in the range.

RESPONSE:

Please refer to the tab "BCUC_1.25.2, 1.25.2.1" in the attached spreadsheet in BC Hydro's response to BCUC IR 1.21.1.

25.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, pp. 88, 91
ABB forecast update

The BCUC Site C Inquiry Final Report includes on page 88 a graphical comparison of Site C Energy Cost to Mid-C market electricity price, and on page 91 a Mid-C average price forecast comparison.

1.25.2 Please update the graph on page 88 of Site C Inquiry Final Report for the most recent ABB forecast and state the currency denomination and location. Please exclude reference to Site C costs from the chart, and include in an excel spreadsheet the data for the Mid-C electricity price forecast and the high/low points in the range.

1.25.2.1 Please provide an additional chart which, in addition to the data included above, plots a line mid-way between BC Hydro's proposed Mid-C market price and ABB's bottom forecast range (Site C Panel Mid-C Forecast). Please provide this data set in an excel spreadsheet. Please describe all assumptions made.

RESPONSE:

Please refer to the tab "BCUC_1.25.2, 1.25.2.1" in the attached spreadsheet in BC Hydro's response to BCUC IR 1.21.1.

25.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, pp. 88, 91
ABB forecast update

The BCUC Site C Inquiry Final Report includes on page 88 a graphical comparison of Site C Energy Cost to Mid-C market electricity price, and on page 91 a Mid-C average price forecast comparison.

1.25.3 Please identify other providers of Mid-C forecasts and explain why BC Hydro has selected the ABB Mid-C forecast.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.4.3.

25.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, pp. 88, 91
ABB forecast update

The BCUC Site C Inquiry Final Report includes on page 88 a graphical comparison of Site C Energy Cost to Mid-C market electricity price, and on page 91 a Mid-C average price forecast comparison.

1.25.3.1 Please update the graph provided on page 91 of the Site C Final Report to show a comparison of the most recent ABB forecast to other the most recent Mid-C forecasts.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.21.1.

26.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit F1-8, BCUC IR 22.1, p. 10, ABB methodology

BC Hydro states on page 10 in response to BCUC IR 2.22.1 in Exhibit F1-8 of the Site C Inquiry:

> Actual Mid C prices over the past five years appear to reflect the estimated variable production cost of [combined cycle gas turbine (CCGT)] generation in most hours. In certain other hours, such as during the spring freshet, as well as other periods of high hydro runoff and high wind generation, Mid C prices were below this value, implying that CCGT generation was not required to meet the load in those hours. In certain other hours, however, Mid C prices exceeded the estimated variable production cost of a CCGT. … For every data release, ABB compares the forecast prices that the model produces to historical prices and market forwards.

1.26.1 Please explain the methodology that is used by ABB to develop its Mid-C energy forecast, and describe to what extent this methodology relies on an assumption that CCGT's are the marginal energy source.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.4.3.

26.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit F1-8, BCUC IR 22.1, p. 10, ABB methodology

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1.26.1.1 Please provide the most recent ABB comparison of forecast prices that the model produces to historical prices and market forwards.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.21.1.

26.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit F1-8, BCUC IR 22.1, p. 10, ABB methodology

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1.26.2 Please provide, in table form and graphically, a comparison of average (all-hours) annual Mid-C price forecast from the ABB Spring 2016 forecast for each year from 2016 to 2018, to the actual values for 2016 to 2017 and year to date for 2018.

RESPONSE:

Please refer to the tab "BCUC_1.26.2" in the attached spreadsheet in BC Hydro's response to BCUC IR 1.21.1.

26.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit F1-8, BCUC IR 22.1, p. 10, ABB methodology

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1.26.3 Please provide, in table form and graphically, a comparison in US $ of (i) ABB Mid-C forecast prices to (ii) actual Intercontinental Exchange (ICE) Mid-C forward contract prices (for each year that this data is available). Please provide a break-down of this data for peak and off-peak, and include data sets from other Mid-C forward markets if available.

RESPONSE:

Please refer to the tab "BCUC_1.26.3" in the attached spreadsheet in BC Hydro's response to BCUC IR 1.21.1.

27.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 94; BCUC 2017 IRP, Chapter 5, p. 5-47
Source of generation, transmission constraints

Page 94 in the Site C Inquiry Final Report states: "BC Hydro states that it has no expectation that it will be limited by transmission capacity in its ability to export any surplus" and in Appendix B (page 1) states: "BC Hydro states … Access to the electricity markets and delivery of the [Columbia River Treaty Entitlement] all rely upon the same I-5 transmission corridor through the Seattle region that is frequently constrained."

BC Hydro states in the 2013 IRP (Chapter 5, p. 5-47): "BC Hydro expects that it will be able to manage the export of available electricity, however transmission limits could reduce the economic value received for those exports."

1.27.1 Please explain whether there are constraints (including transmission constraints) that limit BC Hydro's ability to sell additional surplus energy into the US market. Please specifically address if constraints could limit BC Hydro's ability to sell surplus energy into the Mid-C market during the (i) freshest period, and/or (ii) Mid-C peak pricing periods (within day or seasonally). If yes, please explain whether BC Hydro's market price forecast includes an adjustment for this (and if not, what pricing adjustment would be appropriate to reflect these constraints).

RESPONSE:

BC Hydro sells surplus energy to Powerex pursuant to the Transfer Pricing Agreement (TPA). The ability for Powerex to sell energy in the various markets in which it transacts can be affected by three main constraints: generation capability, transmission availability and market opportunities. However, it is important to keep in mind the time horizon when discussing these constraints. Over the course of a year, typically none of these constraints bind since BC Hydro's surplus in aggregate is generally not large enough to be limited by any of these factors.

In contrast, in a given week, day or hour any of these constraints could arise as the binding constraint. A large number of factors can be involved in determining which constraint is binding in any given period (e.g., time of year, system load,

system maintenance - both generation and transmission, similar factors on neighbouring systems, etc.).

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).

The term "Mid-C peak pricing periods" as used in the question above is not a clearly defined term. As noted above, a complex set of factors are involved in determining the limiting constraint for any given time period.

BC Hydro's market price forecast reflects seasonal variations in electricity market prices such as depressed values during the freshet. It does not reflect the constraints identified above. Rather, BC Hydro includes those constraints in its energy studies modeling which impacts the volumes that can be transacted at a given market price.

27.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 94; BCUC 2017 IRP, Chapter 5, p. 5-47
Source of generation, transmission constraints

Page 94 in the Site C Inquiry Final Report states: "BC Hydro states that it has no expectation that it will be limited by transmission capacity in its ability to export any surplus" and in Appendix B (page 1) states: "BC Hydro states … Access to the electricity markets and delivery of the [Columbia River Treaty Entitlement] all rely upon the same I-5 transmission corridor through the Seattle region that is frequently constrained."

BC Hydro states in the 2013 IRP (Chapter 5, p. 5-47): "BC Hydro expects that it will be able to manage the export of available electricity, however transmission limits could reduce the economic value received for those exports."

1.27.2 Please explain whether the price received by BC Hydro for energy exported into the US market is affected by whether the source generation is specifically identified as run of river or wind (and if so, by how much).

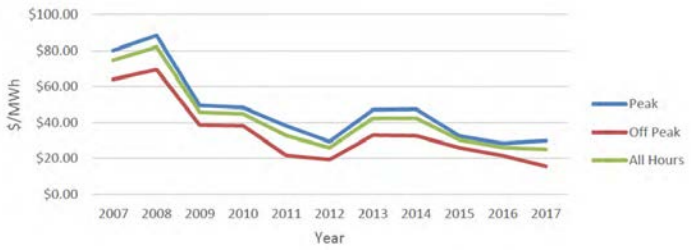
RESPONSE:

The price received by BC Hydro for energy exported into the U.S. market is not affected by the source generation. BC Hydro sells energy to Powerex at a price determined pursuant to the TPA. Although sales to the market by parties other than BC Hydro may be impacted by the source of generation, under the TPA the source of generation does not affect the price BC Hydro receives.

28.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit A-24, Site C Final Report, p. 93, Figure 19, p. 95 Historical trend

Page 93 of the Site C Inquiry – Final Report provides a chart (Figure 19) showing Mid-C (Can$/MWh) average peak, off-oeak and all hours prices by year:



The BCUC states in the Site C Final Report on page 95: "…we know that the current price for electricity has been low for the past few years and it is anticipated it is unlikely to change in the short term. We also know that renewables such as wind and solar are increasingly coming on-stream in the Pacific Northwest and other export markets at increasingly lower prices and this has the potential to impact future market prices and be disruptive."

1.28.1 Please provide, in a working Excel spreadsheet and graphically, over a period covering the last 10 years and forward covering the term of the ABB market price forecast, a comparison of (i) average (all hours) Mid-C actual/BC Hydro forecast US $/MWh values at the Mid-C location; and (ii) average (all hours) Mid-C actual/BC Hydro forecast Can $/MWh values at the Lower Mainland location. Please describe all assumptions used.

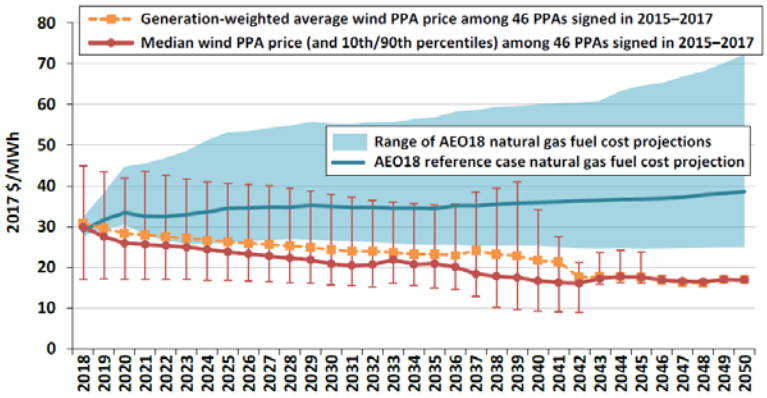
RESPONSE:

Please refer to the tab "BCUC_1.28.1" in the attached spreadsheet in BC Hydro's response to BCUC IR 1.21.1. In this response we have assumed the market price at the Lower Mainland is equivalent to the B.C. Border sell price because BC Hydro's loss factor from the Lower Mainland to the B.C. Border is zero.

29.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 Wind Technologies Market Report, US Department of Energy, Office of Energy Efficiency and Renewable Energy, p. 63[1]; NREL 2018 ATB Spreadsheet Renewable penetration

Page 63 of the 2017 Wind Technologies Market Report includes figure 54 which shows a comparison of wind PPA prices and natural gas fuel costs (in $/MWh) by calendar year:



Note: The 10th/90th percentile range narrows considerably in later years as the PPA sample dwindles

Sources: Berkeley Lab, Energy Information Administration's Annual Energy Outlook 2018 (AEO18)

Figure 54. Wind PPA prices and natural gas fuel cost projections by calendar year over time

The NREL 2018 ATB is available at: https://atb.nrel.gov/. The 'land-based' wind tab (Future Projections) shows a 2018 levelized cost of energy TRG4 mid value of US $39/MWh, decreasing to US $30/MWh by 2036

1.29.1 Please overlay BC Hydro's Mid-C forecast (US $, Mid-C location) on the 2017 Wind Technologies Market Report figure 54 above. Please explain any significant difference to the $/MWh natural gas fuel cost projection provided in the report.

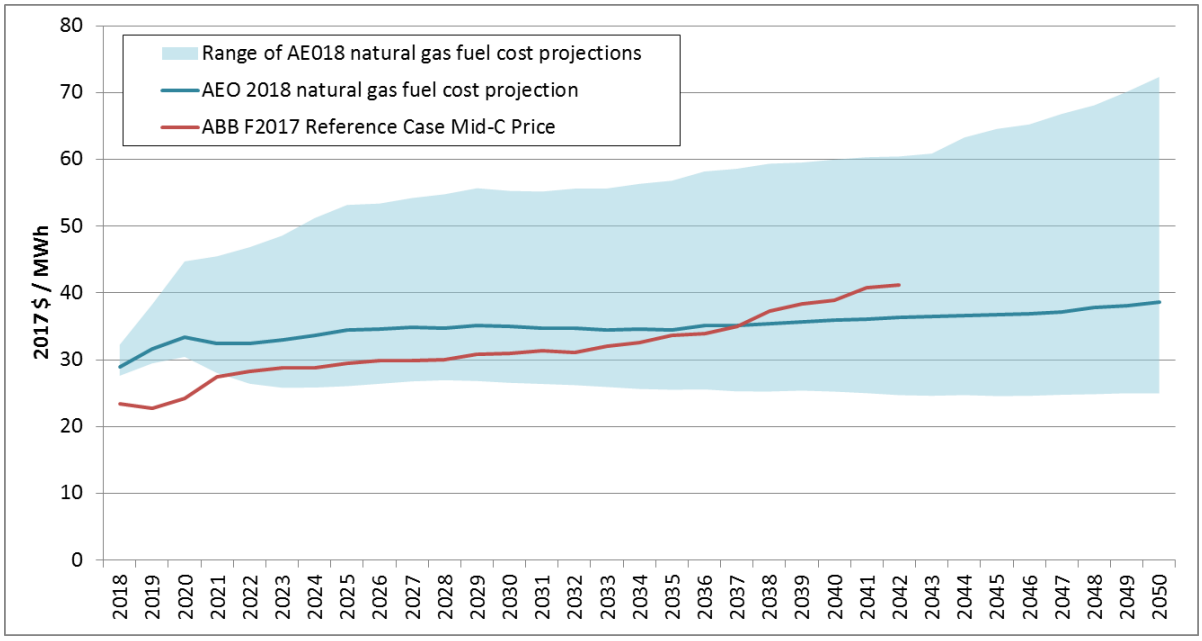
1 https://www.energy.gov/sites/prod/files/2018/08/f54/2017_wind_technologies_market_report_8.15.18.v2.pdf

RESPONSE:

The following figure overlays BC Hydro's most recent Mid C forecast based on the ABB Fall 2017 Reference Case (US $, Mid C location) on the 2017 Wind Technologies Market Report figure 54.

The Mid C market price forecast is based on an hourly simulation of all generating units in the Western Interconnection. Units other than natural gas units set the market price during certain hours of the year, most notably in freshet season. The annual market price is an average of the market price over all hours and would reflect the variable cost of all the different types of units that set the market price over the year. Hence, it is not directly comparable to a $/MWh natural gas fuel cost projection.

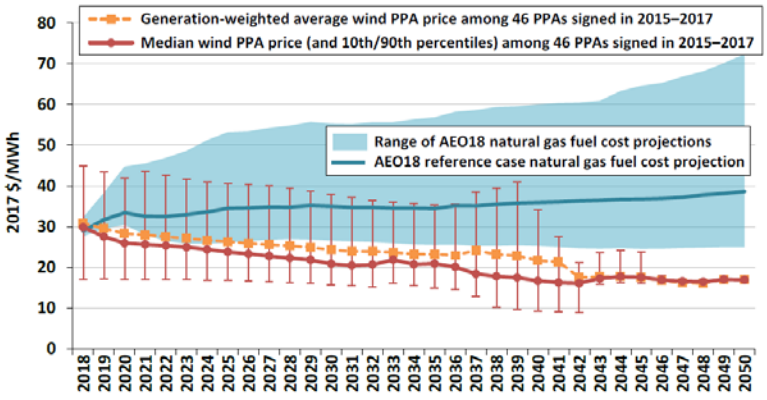
Additionally, the cost of the natural gas commodity ($/MMBtu) that is used in the modelling of the Mid C forecast accounts for differences in the gas commodity price at various locations. The modelling looks at gas prices at 10 market centers in the Western Interconnect. Prices at the market centers are linked with the price at Henry Hub which is the trading hub that sets the benchmark North American gas price and will reflect local supply and demand imbalances. These prices are different than the values used in the NREL 2018 ATB $/MWh natural gas fuel cost projection.



29.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 Wind Technologies Market Report, US Department of Energy, Office of Energy Efficiency and Renewable Energy, p. 63[1]; NREL 2018 ATB Spreadsheet Renewable penetration

Page 63 of the 2017 Wind Technologies Market Report includes figure 54 which shows a comparison of wind PPA prices and natural gas fuel costs (in $/MWh) by calendar year:



Note: The 10th/90th percentile range narrows considerably in later years as the PPA sample dwindles

Sources: Berkeley Lab, Energy Information Administration's Annual Energy Outlook 2018 (AEO18)

Figure 54. Wind PPA prices and natural gas fuel cost projections by calendar year over time

The NREL 2018 ATB is available at: https://atb.nrel.gov/. The 'land-based' wind tab (Future Projections) shows a 2018 levelized cost of energy TRG4 mid value of US $39/MWh, decreasing to US $30/MWh by 2036

1.29.1.1 Please provide, graphically and in an excel spreadsheet, a comparison of (i) the ABB Mid-C forecast (US $, Mid-C location) out to 2036, and (ii) the estimated levelized wind cost (TRG4 mid-value) in US $/MWh from the NREL 2018 ATB for the same period.

1 https://www.energy.gov/sites/prod/files/2018/08/f54/2017_wind_technologies_market_report_8.15.18.v2.pdf

RESPONSE:

Please refer to the tab "BCUC_1.29.1.1" in the attached spreadsheet in BC Hydro's response to BCUC IR 1.21.1.

29.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 Wind Technologies Market Report, US Department of Energy, Office of Energy Efficiency and Renewable Energy, p. 63[1]; NREL 2018 ATB Spreadsheet Renewable penetration

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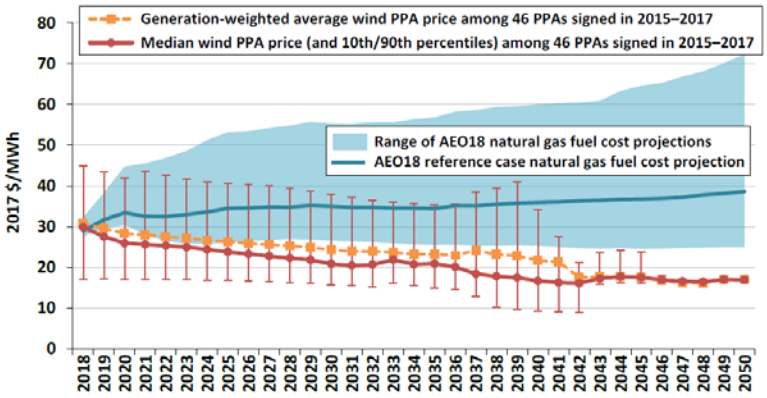

Note: The 10th/90th percentile range narrows considerably in later years as the PPA sample dwindles

Sources: Berkeley Lab, Energy Information Administration's Annual Energy Outlook 2018 (AEO18)

Figure 54. Wind PPA prices and natural gas fuel cost projections by calendar year over time

The NREL 2018 ATB is available at: https://atb.nrel.gov/. The 'land-based' wind tab (Future Projections) shows a 2018 levelized cost of energy TRG4 mid value of US $39/MWh, decreasing to US $30/MWh by 2036

1.29.1.2 In years where the (i) forecast levelized cost of new wind generation and/or (ii) the wind PPA price is below the estimated Mid-C price, does BC Hydro consider that it indicates the Mid-C forecast for that year could be overstated? Please explain.

1 https://www.energy.gov/sites/prod/files/2018/08/f54/2017_wind_technologies_market_report_8.15.18.v2.pdf

RESPONSE:

BC Hydro does not consider the forecast to be overstated in years where the wind PPA price is below the estimated Mid C price. Please refer to BC Hydro's response to BCUC IR 1.29.1.3.

29.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 Wind Technologies Market Report, US Department of Energy, Office of Energy Efficiency and Renewable Energy, p. 63[1]; NREL 2018 ATB Spreadsheet Renewable penetration

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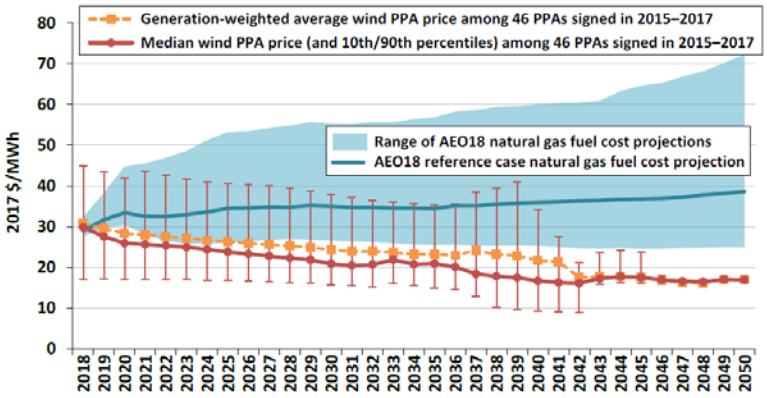


Note: The 10th/90th percentile range narrows considerably in later years as the PPA sample dwindles

Sources: Berkeley Lab, Energy Information Administration's Annual Energy Outlook 2018 (AEO18)

Figure 54. Wind PPA prices and natural gas fuel cost projections by calendar year over time

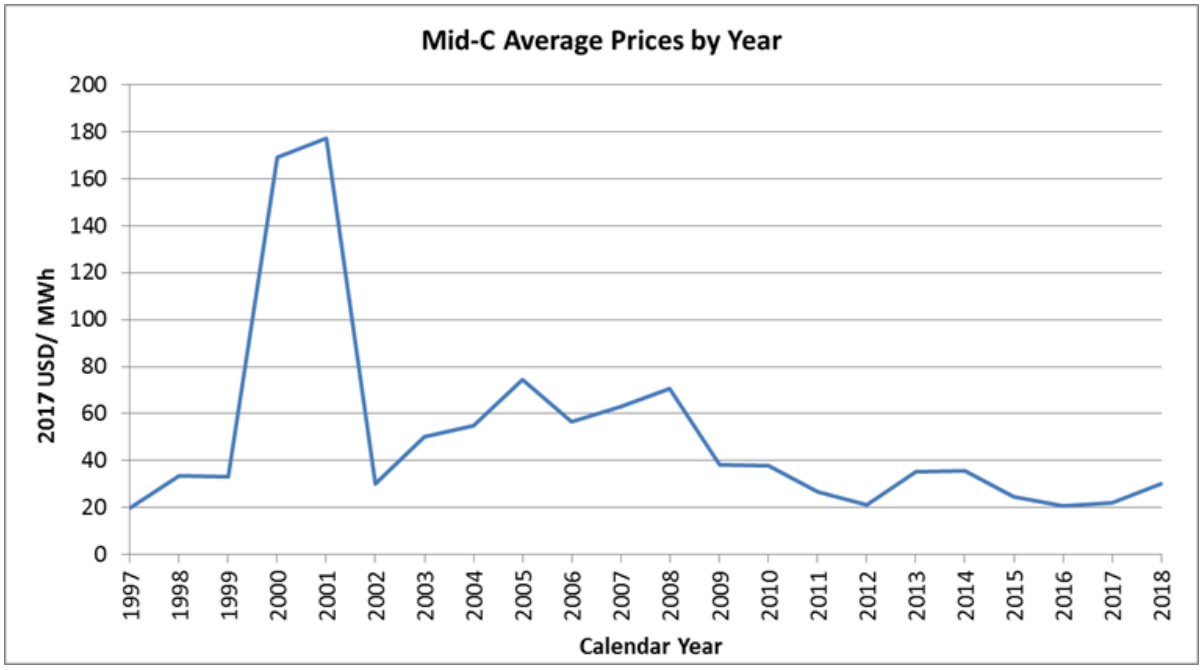
The NREL 2018 ATB is available at: https://atb.nrel.gov/. The 'land-based' wind tab (Future Projections) shows a 2018 levelized cost of energy TRG4 mid value of US $39/MWh, decreasing to US $30/MWh by 2036

1.29.1.3 Please explain whether historically (over the last 20 years) the Mid-C average annual $/MWh price has been higher than the levelized cost of new generation for that year.

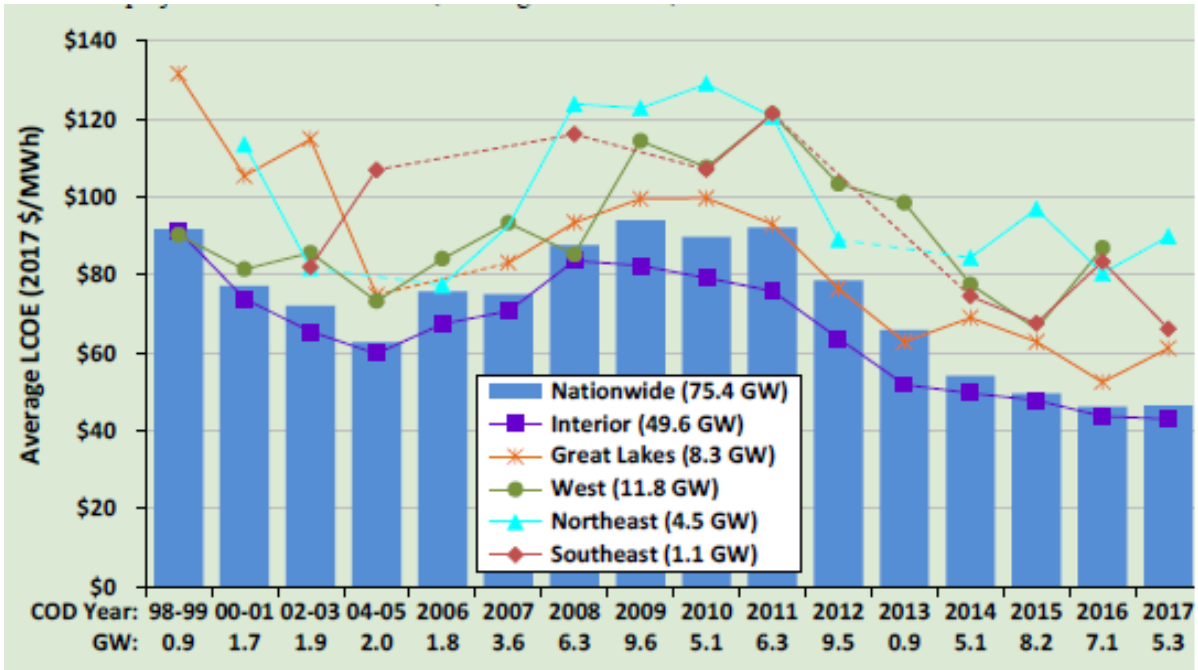
RESPONSE:

The figure below shows historical Mid-C average annual $/MWh prices in 2017 USD.

[1] https://www.energy.gov/sites/prod/files/2018/08/f54/2017_wind_technologies_market_report_8.15.18.v2.pdf



The graphic below extracted from page 65 of the 2017 Wind Technologies Market Report referenced above shows the levelized $/MWh for wind power in 2017 USD.



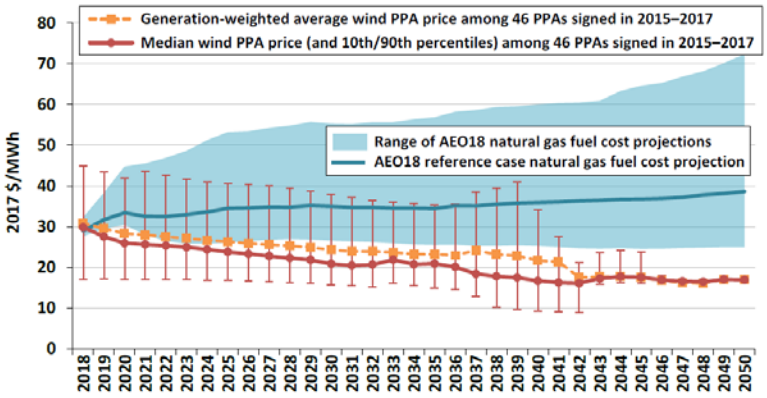
The two sets of values show that the Mid-C average annual price has been lower than the levelized cost of new wind generation built in the same year, with the exception of the period between 2000 to 2001 when both natural gas and electricity market prices spiked during the California electricity crisis.

It is noted that there is no direct link between the levelized cost of wind development and the market price. The electricity market price is set by the variable cost of the dispatchable generator with the lowest operating cost that can meet the marginal demand in the region or in a situation where there is a surplus of non-dispatchable generation, by the operating cost of non-dispatchable resources such as wind, which could be zero or negative in some instances. As more renewables are built there could be higher instances of non-dispatchable generation surplus and the average annual market price would be lower as a result. Such phenomena are reflected in BC Hydro's market electricity price forecast.

29.0 B. ECONOMIC ANALYSIS

Reference: MARKET VALUE OF SURPLUS ENERGY
Exhibit B-1, pp. 12, 20, 31; 2017 Wind Technologies Market Report, US Department of Energy, Office of Energy Efficiency and Renewable Energy, p. 63[1]; NREL 2018 ATB Spreadsheet Renewable penetration

Page 63 of the 2017 Wind Technologies Market Report includes figure 54 which shows a comparison of wind PPA prices and natural gas fuel costs (in $/MWh) by calendar year:



Note: The 10th/90th percentile range narrows considerably in later years as the PPA sample dwindles

Sources: Berkeley Lab, Energy Information Administration's Annual Energy Outlook 2018 (AEO18)

Figure 54. Wind PPA prices and natural gas fuel cost projections by calendar year over time

The NREL 2018 ATB is available at: https://atb.nrel.gov/. The 'land-based' wind tab (Future Projections) shows a 2018 levelized cost of energy TRG4 mid value of US $39/MWh, decreasing to US $30/MWh by 2036

1.29.2 Please explain how BC Hydro considers export price risk in its evaluation of EPA renewals.

RESPONSE:

BC Hydro did not consider export price risk in our evaluation of the EPA renewals in the Application.

[1] https://www.energy.gov/sites/prod/files/2018/08/f54/2017_wind_technologies_market_report_8.15.18.v2.pdf

30.0 B. ECONOMIC ANALYSIS

Reference: EPA SPECIFIC CONSIDERATIONS
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry,
Exhibit F1-4, BCUC IR 2.0, Attachment 1; BC Hydro 2013 IRP,
Appendix 3A-34, pp. 2, 3
Energy/capacity volumes, shape and location adjustments

In Exhibit F1-4 in the Site C Inquiry BC Hydro provided an Excel file (AdjUEC (BCUC Request)) in response to BCUC IR 2.0.

1.30.1 For each EPA, in a working Excel file, please provide the renewed EPA price (in F2018 $) for each year of the contract.

RESPONSE:

The public version of the attachment to this response has been redacted. The public disclosure of this information would prejudice BC Hydro's negotiating position and commercial interests with respect to other EPA renewals.

Please find attached an Excel file that provides the renewed EPA price (in F2018$) for each EPA for each year of its contract term.

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30.0 B. ECONOMIC ANALYSIS

Reference: EPA SPECIFIC CONSIDERATIONS
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit F1-4, BCUC IR 2.0, Attachment 1; BC Hydro 2013 IRP, Appendix 3A-34, pp. 2, 3
Energy/capacity volumes, shape and location adjustments

In Exhibit F1-4 in the Site C Inquiry BC Hydro provided an Excel file (AdjUEC (BCUC Request)) in response to BCUC IR 2.0.

1.30.2 Please update the AdjUEC (BCUC Request) spreadsheet provided in the Site C Inquiry to include as resource options (instead of wind) each EPA renewal included in the Application. Please set the point of interconnection starting cost at (i) an illustrative $85/MWh for each EPA and (ii) the renewed EPA levelized energy price. Please describe all key assumptions made.

RESPONSE:

The public version of the attachment to this response has been redacted. The public disclosure of this information would prejudice BC Hydro's negotiating position and commercial interests with respect to other EPA renewals.

The original spreadsheet provided in the Site C Inquiry was created for a greenfield wind project, with the same monthly generation profile assumed for annual average and annual firm energy. All costs presented were in fiscal 2018 dollars.

The three EPA renewals in this Application are hydro projects, their annual average and annual firm energy are not the same. The updated spreadsheet incorporates detailed annual average and annual firm energy monthly profiles for each of the three EPAs, and all costs were presented in fiscal 2017 dollars.

The "Calculations" tab shows the calculation of the adjustments for each EPA using the requested illustrative example and the levelized EPA price. The option can be changed via the drop-down in cell C2, while the resulting UEC is provided in cell C52.

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30.0 B. ECONOMIC ANALYSIS

Reference: EPA SPECIFIC CONSIDERATIONS
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit F1-4, BCUC IR 2.0, Attachment 1; BC Hydro 2013 IRP, Appendix 3A-34, pp. 2, 3
Energy/capacity volumes, shape and location adjustments

In Exhibit F1-4 in the Site C Inquiry BC Hydro provided an Excel file (AdjUEC (BCUC Request)) in response to BCUC IR 2.0.

1.30.2 Please update the AdjUEC (BCUC Request) spreadsheet provided in the Site C Inquiry to include as resource options (instead of wind) each EPA renewal included in the Application. Please set the point of interconnection starting cost at (i) an illustrative $85/MWh for each EPA and (ii) the renewed EPA levelized energy price. Please describe all key assumptions made.

1.30.2.1 For each EPA, please calculate (in MWh) firm energy as a percentage of total energy that BC Hydro forecasts on average will be delivered each year (using a methodology consistent with that used in the 2013 IRP, Appendix 3A-34).

RESPONSE:

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

BC Hydro provides the requested values in the table below. BC Hydro notes that the values shown are consistent with the values used in the analysis of BC Hydro's opportunity cost, as provided in the Application, and are based on the "Freshet Firm Energy Adjustment" methodology explained in the 2013 IRP, Appendix 3A-34.

	Firm Energy (MWh)	**Firm Energy (% of total energy)**
Sechelt Creek	[redacted]	[redacted]
Brown Lake	[redacted]	[redacted]
Walden North	[redacted]	[redacted]

30.0 B. ECONOMIC ANALYSIS

Reference: EPA SPECIFIC CONSIDERATIONS
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry,
Exhibit F1-4, BCUC IR 2.0, Attachment 1; BC Hydro 2013 IRP,
Appendix 3A-34, pp. 2, 3
Energy/capacity volumes, shape and location adjustments

In Exhibit F1-4 in the Site C Inquiry BC Hydro provided an Excel file (AdjUEC (BCUC Request)) in response to BCUC IR 2.0.

1.30.3 Please use the results of the AdjUEC spreadsheet above to prepare a spreadsheet for each EPA in the Application that identifies the volumes of (i) firm and (ii) non-firm energy and capacity expected to be delivered for each year of the contract. For Walden North Hydro, please gross up volumes for any downstream benefits and exclude volumes BC Hydro has already committed to as a result of the Forbearance Agreement. Please explain all adjustments and assumptions made.

RESPONSE:

BC Hydro provides the requested information in the "Before Losses" worksheet of the attached spreadsheet. The public version of this response and the attached spreadsheet has been redacted to maintain in confidence commercially sensitive information. The public disclosure of this information would prejudice BC Hydro's negotiating position and commercial interests with respect to other EPA renewals.

BC Hydro notes that the information in the attached reflects the annual firm and non-firm energy amounts based on the "Freshet Firm Energy Adjustment" methodology explained in the 2013 IRP, Appendix 3A-34. In addition, the volumes shown reflect the specific EPA terms (for the three EPA renewals) and planned refurbishments (for Walden North only) which means that there are different energy volumes in some years (e.g., in the first year of the contract is a partial year). BC Hydro also notes that the energy volumes used in Attachment 1 to BC Hydro's response to BCUC IR 1.30.2 are based on one long term (i.e., post-refurbishment) annual energy volume (without reductions) for each EPA renewal because the model is not configured to allow for variable annual energy volumes. For the purposes of the analysis in the attached spreadsheet, BC Hydro assumes that the Forbearance Agreement terminates in [redacted].

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30.0 B. ECONOMIC ANALYSIS

Reference: EPA SPECIFIC CONSIDERATIONS
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry,
Exhibit F1-4, BCUC IR 2.0, Attachment 1; BC Hydro 2013 IRP,
Appendix 3A-34, pp. 2, 3
Energy/capacity volumes, shape and location adjustments

In Exhibit F1-4 in the Site C Inquiry BC Hydro provided an Excel file (AdjUEC (BCUC Request)) in response to BCUC IR 2.0.

1.30.3 Please use the results of the AdjUEC spreadsheet above to prepare a spreadsheet for each EPA in the Application that identifies the volumes of (i) firm and (ii) non-firm energy and capacity expected to be delivered for each year of the contract. For Walden North Hydro, please gross up volumes for any downstream benefits and exclude volumes BC Hydro has already committed to as a result of the Forbearance Agreement. Please explain all adjustments and assumptions made.

1.30.3.1 For each EPA, please reduce these energy/capacity volumes to reflect energy losses associated with delivery to the Lower Mainland. Please explain the methodology used to make this adjustment.

RESPONSE:

Please refer to the "After Losses" worksheet in the attachment to BC Hydro's response to BCUC IR 1.30.3. The spreadsheet has been redacted to maintain in confidence commercially sensitive information. The public disclosure of this information would prejudice BC Hydro's negotiating position and commercial interests with respect to other EPA renewals.

The energy/capacity losses are calculated based on the methodology described in the BCTC's January 2010 report, using the results for year 2014/2015. Please refer to BCUC IR 1.18.1.1 for more details.

30.0 B. ECONOMIC ANALYSIS

Reference: EPA SPECIFIC CONSIDERATIONS
Exhibit B-1, pp. 12, 20, 31; 2017 BCUC Site C Inquiry, Exhibit F1-4, BCUC IR 2.0, Attachment 1; BC Hydro 2013 IRP, Appendix 3A-34, pp. 2, 3
Energy/capacity volumes, shape and location adjustments

In Exhibit F1-4 in the Site C Inquiry BC Hydro provided an Excel file (AdjUEC (BCUC Request)) in response to BCUC IR 2.0.

1.30.4 For each EPA, please also update the AdjUEC spreadsheet to include an estimate of the following $/MWh charges specific to each EAP: CIFT; line loss, capacity credit, and network upgrade. Please provide supporting calculations/assumptions used.

RESPONSE:

The CIFT adjustment is not applicable to EPA renewals as they are existing projects not expected to trigger any new transmission system reinforcements.

The capacity credit is not applicable to Sechelt Creek and Walden North as they do not provided dependable capacity. The capacity credit is applicable to Brown Lake, and is reflected in the updated AdjUEC spreadsheet attached in BC Hydro's response to BCUC IR 1.30.2.

Please refer to the same AdjUEC spreadsheet for the line loss and network upgrade estimates for each of the three EPA renewals.

31.0 B. ECONOMIC ANALYSIS

Reference: EPA SPECIFIC CONSIDERATIONS
Exhibit B-1, pp. 24, 29, 30, 35
Walden North – water diversion benefits

BC Hydro states on page 24 of the Application that the Walden North facility is located downstream of BC Hydro's Seton Dam and that it provides support to BC Hydro facilities in relation to generation and water flow.

1.31.1 Please clarify whether the Walden North facility is located upstream or downstream of BC Hydro's Seton Dam, and describe how it provides additional downstream generation to BC Hydro.

RESPONSE:

Please refer to Appendix G of the Application which provides a site layout for the Walden North project and adjacent BC Hydro facilities.

The Walden North IPP is located on Cayoosh Creek, and Cayoosh Creek water (that does not get diverted by the IPPs works into BC Hydro's Cayoosh Diversion Tunnel and Seton Lake) flows into Seton River downstream of Seton Dam.

BC Hydro's Cayoosh Diversion Tunnel, which feeds water from Cayoosh Creek into Seton Lake, is upstream of Seton Dam. This additional upstream water, which is fed into Seton Lake, is used to generate energy at Seton Generating Station.

31.0 B. ECONOMIC ANALYSIS

Reference: EPA SPECIFIC CONSIDERATIONS
Exhibit B-1, pp. 24, 29, 30, 35
Walden North – water diversion benefits

BC Hydro states on page 24 of the Application that the Walden North facility is located downstream of BC Hydro's Seton Dam and that it provides support to BC Hydro facilities in relation to generation and water flow.

1.31.1 Please clarify whether the Walden North facility is located upstream or downstream of BC Hydro's Seton Dam, and describe how it provides additional downstream generation to BC Hydro.

1.31.1.1 Please describe the expected seasonal shape of this additional generation, including the percentage of the downstream generation that is in the May to June freshet season.

RESPONSE:

BC Hydro has attributed the following expected seasonal shape of the additional downstream generation at Seton to the upstream water flows from the Cayoosh Diversion Tunnel:

- **February to April is approximately 15 per cent;**
- **May to July is approximately 9 per cent, with a negligible amount attributed during May and June;**
- **August to October is approximately 48 per cent; and**
- **November to January is approximately 28 per cent.**

Therefore, approximately 91 per cent of this generation is outside of the freshet season.

31.0 B. ECONOMIC ANALYSIS

Reference: EPA SPECIFIC CONSIDERATIONS
Exhibit B-1, pp. 24, 29, 30, 35
Walden North – water diversion benefits

BC Hydro states on page 35 of the Application that the Walden North IPP has advised that the facility will not be decommissioned or decommissioned earlier if the EPA is not renewed.

1.31.2 If the Walden North EPA is not renewed, please explain (i) to what extent BC Hydro would no longer receive downstream generation benefits, (ii) to what extent BC Hydro would no longer receive dilution ratio benefits; and (iii) in each case, whether BC Hydro could reasonably be expected to be able to enter into a diversion agreement to maintain these benefits (and if so, at what cost).

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.5.1.

31.0 B. ECONOMIC ANALYSIS

Reference: EPA SPECIFIC CONSIDERATIONS
Exhibit B-1, pp. 24, 29, 30, 35
Walden North – water diversion benefits

BC Hydro states on page 29 of the Application that the Bridge River generation system is currently curtailed or restricted during the summer period and that there are water management issues during the freshet period. BC Hydro states on page 30 of the Application that the Walden North EPA renewal provides more robust rights for BC Hydro to turn down Walden North generation and to close the Cayoosh Diversion Tunnel.

1.31.3 If the Walden North EPA is not renewed, please explain the effect on BC Hydro's water management of the Bridge River generation system. Specifically, would the effect be operational or financial, and what would that effect be?

RESPONSE:

As provided at the end of section 6.2 of the Application, if the Walden North EPA renewal is not accepted, the original EPA and the Forbearance Agreement will remain in effect in accordance with their respective terms. If there is no EPA with BC Hydro, the Diversion Agreement terminates. Without an EPA and Diversion Agreement, there would be uncertainties regarding how the parties will manage water flows in relation to the diversion tunnel.

Specifically, there will be uncertainties with respect to how the parties will coordinate in relation to the dilution ratio for fish and there will be uncertainties on whether or not the Cayoosh Diversion Tunnel will be able to provide an additional 24.4 GWh to BC Hydro's Bridge River system. These impacts would likely be operational, environmental and financial; however, these impacts have not been quantified.

Please also refer to BC Hydro's response to BCUC IR 1.5.1.

31.0 B. ECONOMIC ANALYSIS

Reference: EPA SPECIFIC CONSIDERATIONS
Exhibit B-1, pp. 24, 29, 30, 35
Walden North – water diversion benefits

BC Hydro states on page 29 of the Application that the Bridge River generation system is currently curtailed or restricted during the summer period and that there are water management issues during the freshet period. BC Hydro states on page 30 of the Application that the Walden North EPA renewal provides more robust rights for BC Hydro to turn down Walden North generation and to close the Cayoosh Diversion Tunnel.

1.31.3 If the Walden North EPA is not renewed, please explain the effect on BC Hydro's water management of the Bridge River generation system. Specifically, would the effect be operational or financial, and what would that effect be?

1.31.3.1 Please explain whether BC Hydro could mitigate these effects, and if yes, to what extent and at what cost?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.31.3.

31.0 B. ECONOMIC ANALYSIS

Reference: EPA SPECIFIC CONSIDERATIONS
Exhibit B-1, pp. 24, 29, 30, 35
Walden North – water diversion benefits

BC Hydro states on page 30 of the Application that the Walden North tailrace culverts need to be upgraded and that it will contribute toward the IPPs cost for such work.

1.31.4 If the Walden North EPA is not renewed, would there be any effect on BC Hydro's proposal to contribute towards the tailrace upgrade project? If yes, please describe.

RESPONSE:

If the Walden North EPA renewal does not proceed, BC Hydro will have no obligation to contribute to the tailrace upgrade project as provided in the Walden North EPA renewal. In such circumstance, contributions from BC Hydro towards a Walden North tailrace upgrade project may be the subject of any new negotiations with the Walden North IPP.

32.0 B. ECONOMIC ANALYSIS

Reference: EPA SPECIFIC CONSIDERATIONS
Exhibit B-1, pp. 17, 23
Brown Lake: Reliability benefits

BC Hydro states on page 17 of the Application that the storage capability at the Brown Lake facility allows BC Hydro to support local reliability. BC Hydro states on page 23 of the Application that the Brown Lake IPP has advised that the facility will not be decommissioned or decommissioned earlier if the EPA is not renewed.

1.32.1 Please explain whether there would be detrimental impacts on local reliability if the Brown Lake EPA was not renewed, and if yes, whether (i) service would decline to below acceptable levels, and (ii) whether BC Hydro could mitigate these impacts (and if so, how).

RESPONSE:

The Brown Lake IPP is one of three resources which provide local reliability to the Prince Rupert area. If the Brown Lake EPA renewal does not proceed, BC Hydro would continue to have the other two resources available and service would not decline below acceptable levels. However, if the Prince Rupert Generating Station is used, it is a more costly and less environmentally acceptable alternative than using the Brown Lake IPP. Please refer to BC Hydro's response to BCUC IR 1.37.1.

33.0 B. ECONOMIC ANALYSIS

Reference: EPA SPECIFIC CONSIDERATIONS
Exhibit B-1, pp. 14, 21, 33
Risk Allocation

BC Hydro states in the Application that examples of the risks born by the IPP include uncertainty regarding water rental and property tax increases, equipment failure, diversion restrictions, reduced water flows and (for Walden North) the refurbishment project.

1.33.1 For each risk described above, please explain whether costs for ratepayers could be lower overall if BC Hydro, rather than the IPP, took on these risks.

RESPONSE:

The risks identified above are generally uncertainties borne by a project owner who operates and controls its facility. BC Hydro has not conducted an analysis to assess how a shifting of risk from the project owner to BC Hydro would impact the EPA terms and conditions and price.

33.0 B. ECONOMIC ANALYSIS

Reference: EPA SPECIFIC CONSIDERATIONS
Exhibit B-1, pp. 14, 21, 33
Risk Allocation

BC Hydro states in the Application that examples of the risks born by the IPP include uncertainty regarding water rental and property tax increases, equipment failure, diversion restrictions, reduced water flows and (for Walden North) the refurbishment project.

1.33.2 To what extent, if any, does BC Hydro consider that renewing existing IPP EPAs lowers the investment risk perceived by investors in new IPPs, and so could lead to cost decreases for ratepayers over the long-term. Please explain.

RESPONSE:

BC Hydro has not considered and is not able to speculate as to whether the renewal of existing IPP EPAs has an impact on perceptions of risks by investors in new IPPs.

33.0 B. ECONOMIC ANALYSIS

Reference: EPA SPECIFIC CONSIDERATIONS
Exhibit B-1, pp. 14, 21, 33
Risk Allocation

BC Hydro states in the Application that examples of the risks born by the IPP include uncertainty regarding water rental and property tax increases, equipment failure, diversion restrictions, reduced water flows and (for Walden North) the refurbishment project.

1.33.3 For each EPA in this Application, please provide an estimate (in $/MWh) of (i) water rentals and (ii) property taxes paid by the IPPs.

RESPONSE:

The public version of this response has been redacted to maintain in confidence commercially sensitive information.The redacted information was provided to BC Hydro by the IPPs and public disclosure of this information would be harmful to the commercial interests of the IPP.

Based on information provided by the IPPs and the actual generation production in 2018 for each of the facilities, we provide the following estimated values $/MWh (2018):

	Sechelt Creek	Brown Lake	Walden North
Water rentals	[redacted]	[redacted]	[redacted]
Property Taxes	[redacted]	[redacted]	[redacted]

34.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: OPERATION AND MAINTENANCE RISK ASSESSMENT
Exhibit B-1, p. 13

On page 13 of the Application, BC Hydro summarizes the risk assessment report conducted by an independent third-party consulting firm:

> At BC Hydro's request, the O&M and capital plans were reviewed by an independent third-party consulting firm retained by the IPP. The consultant found that the forecasted O&M costs are "generally consistent with good engineering practice and generally meet hydroelectric industry practice". As well, the capital plans appear to address facility needs for continued reliable operation and the estimated expenditures appear to be "adequate and appropriately conservative."

1.34.1 Please provide the engineering consulting reports for Sechelt Creek, Brown Lake and Walden North facilities that confirm the operation and maintenance (O&M) costs and capital expenditure plans are consistent with industry standards.

RESPONSE:

The public version of this response does not include the attachments. The attachments are proprietary to a third party, and public disclosure of this information would be harmful to the commercial interests of the third party.

Each of the IPPs retained an independent third party consultant to conduct a condition assessment of each of their respective facilities. The Sechelt Creek IPP also asked its consultant to comment on the capital plans and the operations and maintenance procedures, practices, and costs of its facility. Attached on a confidential basis are those reports. These reports include commercially sensitive material and are considered confidential by the IPPs.

BC Hydro notes that we retained our own consulting firm to review the operation and maintenance (O&M) costs and capital expenditure plans for the Brown Lake and Walden North IPPs but final reports were not requested by BC Hydro as we were satisfied with the information provided in the preliminary draft reports. For the Sechelt Creek IPP, BC Hydro was satisfied with the level of detail provided by the Sechelt Creek's consultant and no further reports were required.

CONFIDENTIAL ATTACHMENT

FILED WITH BCUC ONLY

35.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: SECHELT CREEK EPA
Exhibit B-1, p. 9

On page 9 of the Application, BC Hydro states the unique benefits Sechelt Creek IPP provides as follows:

> The Sechelt Creek project is located close to BC Hydro's load centre, delivers a relatively high proportion of its annual energy during BC Hydro's peak load months (December and January), and has a high annual capacity factor. The project has been recognized for its environmental stewardship, including efforts to enhance the salmon run in Sechelt Creek.

1.35.1 Prior to the Sechelt Creek IPP, how did BC Hydro provide energy to the load centers and would those alternatives be viable if the Sechelt Creek EPA was not renewed?

RESPONSE:

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.

35.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: SECHELT CREEK EPA
Exhibit B-1, p. 9

On page 9 of the Application, BC Hydro states the unique benefits Sechelt Creek IPP provides as follows:

> The Sechelt Creek project is located close to BC Hydro's load centre, delivers a relatively high proportion of its annual energy during BC Hydro's peak load months (December and January), and has a high annual capacity factor. The project has been recognized for its environmental stewardship, including efforts to enhance the salmon run in Sechelt Creek.

1.35.1 Prior to the Sechelt Creek IPP, how did BC Hydro provide energy to the load centers and would those alternatives be viable if the Sechelt Creek EPA was not renewed?

1.35.1.1 If those options are not available or economically viable, please provide a detailed description and associated costs on how BC Hydro would replace the energy provided by the Sechelt Creek IPP to the local load centres.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.35.1.

36.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: SECHELT CREEK EPA RENEWAL
Exhibit B-1, p. 16

On page 16 of the Application, BC Hydro states, "It is uncertain whether the Sechelt Creek facility would be decommissioned or decommissioned earlier in the event the EPA is not renewed."

1.36.1 If the EPA is not renewed, what are MPT Hydro LP intentions for the Sechelt Creek facility and the energy generated?

RESPONSE:

MPT Hydro LP has not communicated to BC Hydro its intentions for the Sechelt Creek facility and the energy generated in the event the EPA is not renewed. BC Hydro has been advised by MPT Hydro LP that the lack of an EPA renewal would introduce several unknowns for the facility and in light of these uncertainties, MPT Hydro LP is not in a position to make a decision on the future of the facility in the absence of an EPA renewal with BC Hydro.

37.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: BROWN LAKE EPA
Exhibit B-1, p. 17

On page 17 of the Application, BC Hydro states the unique benefits Brown Lake IPP provides as follows:

> The Brown Lake project has a high annual capacity factor and delivers a high proportion of its annual energy during BC Hydro's peak load months and a low proportion of its annual energy during the freshet season.
>
> BC Hydro's transmission line connecting the Prince Rupert area to BC Hydro's integrated system covers mountainous terrain and is subject to significant natural hazard risk, which has resulted in extended forced outages for the Prince Rupert community. The transmission line also requires planned outages to conduct annual maintenance work. The storage capability at the Brown Lake facility allows BC Hydro to support local reliability in the Prince Rupert area, acting as standby resource in case of an outage for BC Hydro's transmission line.

1.37.1 Please provide the electrical one-line diagram showing the referenced transmission line, the Brown Lake IPP interconnection and the load centres around Prince Rupert needing local reliability support from the Brown Lake IPP.

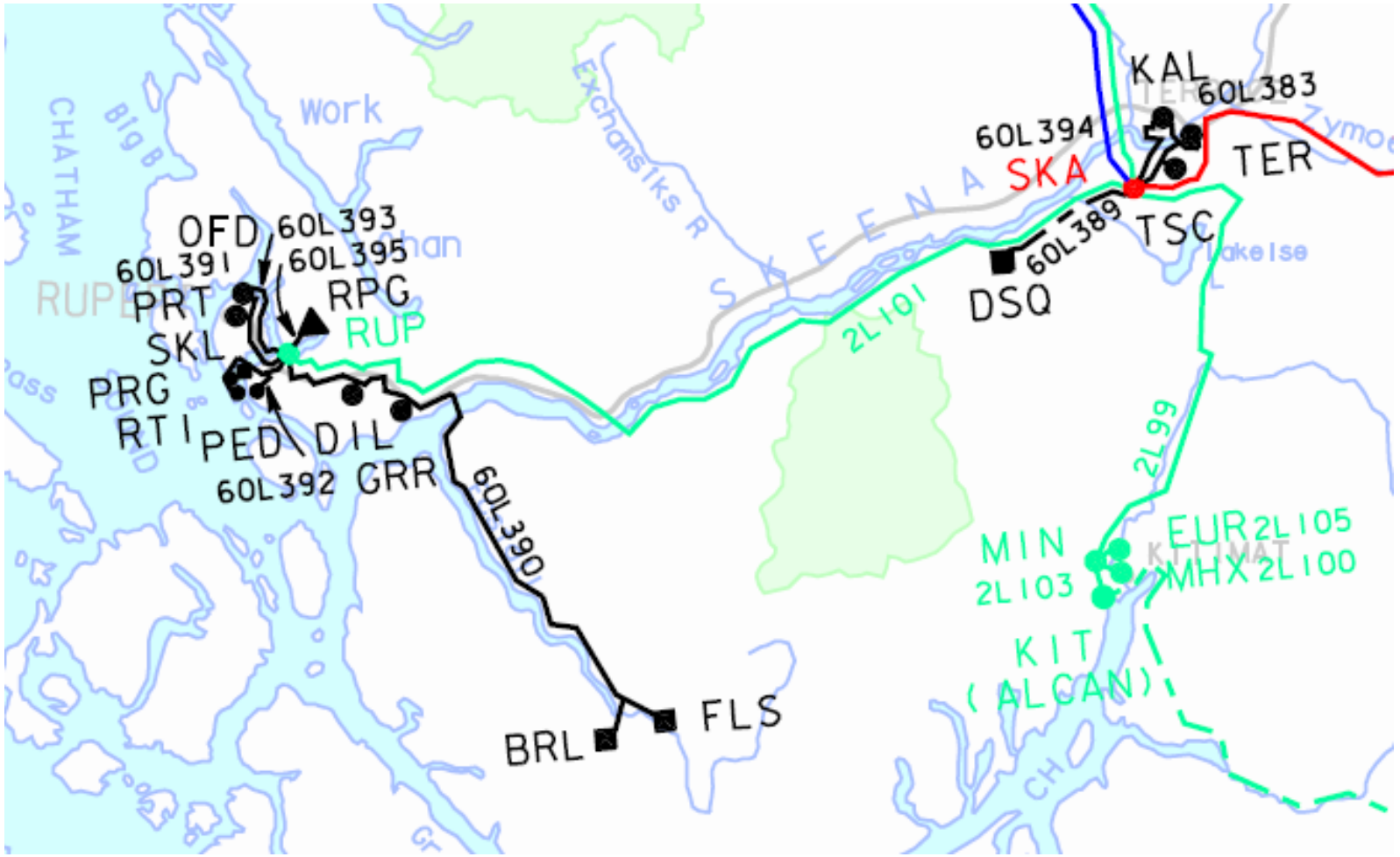
RESPONSE:

The BC Hydro transmission line to the Prince Rupert area is 2L101 which runs along the Skeena River. Please see attached electrical one-line diagram showing the referenced transmission line, the Brown Lake IPP and the Prince Rupert load centre.

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. The generation output from the Brown Lake IPP allows BC Hydro to reduce the output required from the Prince Rupert Generating Station which is a more costly alternative, and would emit greenhouse gases, as compared to the hydro facilities.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EUR
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MHX
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KIT
(ALCAN)
SKEENA
Work
CHATHAM

37.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: BROWN LAKE EPA
Exhibit B-1, p. 17

On page 17 of the Application, BC Hydro states the unique benefits Brown Lake IPP provides as follows:

> The Brown Lake project has a high annual capacity factor and delivers a high proportion of its annual energy during BC Hydro's peak load months and a low proportion of its annual energy during the freshet season.
>
> BC Hydro's transmission line connecting the Prince Rupert area to BC Hydro's integrated system covers mountainous terrain and is subject to significant natural hazard risk, which has resulted in extended forced outages for the Prince Rupert community. The transmission line also requires planned outages to conduct annual maintenance work. The storage capability at the Brown Lake facility allows BC Hydro to support local reliability in the Prince Rupert area, acting as standby resource in case of an outage for BC Hydro's transmission line.

1.37.2 Is the referenced transmission line the only method for BC Hydro to service the Prince Rupert area and if so, please provide the annual scheduled (O&M) and unscheduled (natural hazards) outage hours from the last four years?

RESPONSE:

The referenced transmission line is not the only method for BC Hydro to service the Prince Rupert area. Please refer to BC Hydro's response to BCUC IR 1.37.1.

37.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: BROWN LAKE EPA
Exhibit B-1, p. 17

On page 17 of the Application, BC Hydro states the unique benefits Brown Lake IPP provides as follows:

> The Brown Lake project has a high annual capacity factor and delivers a high proportion of its annual energy during BC Hydro's peak load months and a low proportion of its annual energy during the freshet season.
>
> BC Hydro's transmission line connecting the Prince Rupert area to BC Hydro's integrated system covers mountainous terrain and is subject to significant natural hazard risk, which has resulted in extended forced outages for the Prince Rupert community. The transmission line also requires planned outages to conduct annual maintenance work. The storage capability at the Brown Lake facility allows BC Hydro to support local reliability in the Prince Rupert area, acting as standby resource in case of an outage for BC Hydro's transmission line.

1.37.3 Prior to the Brown Lake IPP, how did BC Hydro reliably provide energy to the Prince Rupert area if the referenced transmission line was out of service?

RESPONSE:

Prior to the Brown Lake IPP, if the referenced transmission line was out of service, the Prince Rupert Generating Station and the Falls River Generating Station provided support to local reliability in the Prince Rupert area. BC Hydro notes that the Prince Rupert Generation Station is a more costly alternative than using the Brown Lake IPP. Please also refer to BC Hydro's response to BCUC IR 1.37.1.

37.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: BROWN LAKE EPA
Exhibit B-1, p. 17

On page 17 of the Application, BC Hydro states the unique benefits Brown Lake IPP provides as follows:

> The Brown Lake project has a high annual capacity factor and delivers a high proportion of its annual energy during BC Hydro's peak load months and a low proportion of its annual energy during the freshet season.
>
> BC Hydro's transmission line connecting the Prince Rupert area to BC Hydro's integrated system covers mountainous terrain and is subject to significant natural hazard risk, which has resulted in extended forced outages for the Prince Rupert community. The transmission line also requires planned outages to conduct annual maintenance work. The storage capability at the Brown Lake facility allows BC Hydro to support local reliability in the Prince Rupert area, acting as standby resource in case of an outage for BC Hydro's transmission line.

1.37.4 Is employing hydro storage IPP as a standby resource for transmission line failures standard for BC Hydro, and if not, why has BC Hydro decided not to utilize standard alternatives, such as Protection and Control (P&C) planning, distributed generation or additional capital infrastructure to mitigate outage events.

RESPONSE:

BC Hydro does not generally employ hydro storage IPPs as a standby resource for transmission line failures as our standard practice is to utilize other alternatives, such as Protection and Control planning, distributed thermal generation and/or additional capital infrastructure to mitigate outage events.

Please also refer to BC Hydro's response to BCUC IR 1.37.1.

37.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: BROWN LAKE EPA
Exhibit B-1, p. 17

On page 17 of the Application, BC Hydro states the unique benefits Brown Lake IPP provides as follows:

> The Brown Lake project has a high annual capacity factor and delivers a high proportion of its annual energy during BC Hydro's peak load months and a low proportion of its annual energy during the freshet season.
>
> BC Hydro's transmission line connecting the Prince Rupert area to BC Hydro's integrated system covers mountainous terrain and is subject to significant natural hazard risk, which has resulted in extended forced outages for the Prince Rupert community. The transmission line also requires planned outages to conduct annual maintenance work. The storage capability at the Brown Lake facility allows BC Hydro to support local reliability in the Prince Rupert area, acting as standby resource in case of an outage for BC Hydro's transmission line.

1.37.5 In table format, if the Brown Lake EPA is not renewed, please list the possible alternative reliability solutions and associated costs to how BC Hydro would provide service to the Prince Rupert area.

RESPONSE:

This response includes commercially sensitive information which has been redacted in the public version of the response as BC Hydro considers this to be confidential information which may impact other EPA renewal negotiations.

During a transmission line outage on 2L101, BC Hydro estimates that each MWh of output from the Brown Lake IPP would reduce the operating cost of Prince Rupert generating station by $[redacted]/MWh.

Alternative Reliability Solution	Levelized energy price ($2018)
Provide additional generation output from Prince Rupert generating station	**$[redacted]/MWh**

38.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: BROWN LAKE EPA RENEWAL
Exhibit B-1, p. 23

On page 23 of the Application, BC Hydro states:

> The Brown Lake facility will not be decommissioned or decommissioned earlier if the EPA is not renewed. In the absence of an EPA renewal with BC Hydro, the Brown Lake IPP's intention and preferred course of action is to sell energy to another party.

1.38.1 If Brown Miller Power Limited Partnership intends to sell energy to another party in absence of an EPA, would this be economically viable when comparing the Brown Lake IPPs operation and maintenance costs to Mid-C market prices.

RESPONSE:

BC Hydro is not able to make this assessment on behalf of the IPP. In response to this question and BCUC IR 1.38.2, the Brown Lake IPP has advised BC Hydro of the following:

> **"There is no specific process available in British Columbia to sell the electricity generated by an independent power producer to an offtaker other than BC Hydro under an EPA. In the absence of EPA renewal, one alternative could potentially be to sell the electricity generated to Powerex, a wholly-owned subsidiary of BC Hydro, who would in turn trade that generated electricity on energy markets. This option may not be viable, and therefore no specific studies have been completed to access long-term firm available transmission capacity."**

38.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: BROWN LAKE EPA RENEWAL
Exhibit B-1, p. 23

On page 23 of the Application, BC Hydro states:

> The Brown Lake facility will not be decommissioned or decommissioned earlier if the EPA is not renewed. In the absence of an EPA renewal with BC Hydro, the Brown Lake IPP's intention and preferred course of action is to sell energy to another party.

1.38.2 If Brown Lake IPP intends to sell energy to another party, does the Brown Lake facility have access to long term firm available transmission capacity?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.38.1.

38.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: BROWN LAKE EPA RENEWAL
Exhibit B-1, p. 23

On page 23 of the Application, BC Hydro states:

> The Brown Lake facility will not be decommissioned or decommissioned earlier if the EPA is not renewed. In the absence of an EPA renewal with BC Hydro, the Brown Lake IPP's intention and preferred course of action is to sell energy to another party.

1.38.3 Since the Brown Lake facility will not be decommissioned, please explain whether BC Hydro and the Prince Rupert area maintain storage and reliability benefits in the absence of an EPA with Brown Lake.

RESPONSE:

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.

39.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: WALDEN NORTH EPA
Exhibit B-1, pp. 6, 25; Appendix G, pp. 1-4

BC Hydro website, Bridge River system upgrades[1]

On page 6 of the Application, BC Hydro states the unique benefits Walden North IPP provides as follows:

> The Walden North EPA renewal enables the continued diversion of water from Cayoosh Creek into Seton Lake which allows for additional BC Hydro generation at the Seton Generating Station (Seton GS) and maintains the dilution ratio supportive of fish spawning in the Bridge River system. In the absence of the EPA renewal, alternative arrangements for diversion to Seton Lake would be required and may not be feasible due to cost and environmental considerations.

On page 25 of the Application, BC Hydro provides further specifications of the benefits from Walden North IPP:

- On average, approximately 20 GWh/yr is generated from water diverted through the Cayoosh Diversion Tunnel after consideration of other Bridge River system constraints. A portion of this incremental generation is outside of the freshet season.
- Diversion of Cayoosh Creek water facilitates maintenance of the dilution ratio of Seton River water to Cayoosh Creek water below the Cayoosh confluence which we understand facilitates salmon migration to spawning areas in the Bridge River system, via Seton River and Seton Lake.

On BC Hydro's website, major projects along the Bridge River System are detailed as follows:

> We're [BC Hydro] planning more than 100 major projects in the system, including:
>
> - Generating unit upgrades at Bridge 2
> - Slope drainage improvements
>
> Our Bridge River facilities are between 55 and 70 years old, and need to be updated.

[1] https://www.bchydro.com/energy-in-bc/projects/bridge-river-projects.html

The electricity generated on the system accounts for about 6% of BC Hydro's total generation. These facilities are capable of generating 550 MW of power but are currently restricted to less than 455 MW.

We're spending almost $400 million between 2015 and 2019 to re-power our Bridge River facilities.

1.39.1 Prior to the Walden North IPP, how did BC Hydro maintain the dilution ratio supportive of fish spawning in the Bridge River system?

RESPONSE:

The Cayoosh Diversion Tunnel was built by BC Hydro in approximately 1957 as part of the construction of the Seton Dam and generating station works. When the diversion tunnel was closed after that construction was completed, the salmon were observed delaying at Seton Generating Station's tailrace. Subsequently, studies found that salmon migration delays were caused by the closure of the Cayoosh Diversion Tunnel and the dilution of Seton River by Cayoosh Creek. These studies established dilution ratio targets for the Seton River that would allow for successful salmon migration. In the early 1980s, the diversion tunnel was re-activated to help maintain dilution ratios.

39.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: WALDEN NORTH EPA
Exhibit B-1, pp. 6, 25; Appendix G, pp. 1-4

BC Hydro website, Bridge River system upgrades[1]

On page 6 of the Application, BC Hydro states the unique benefits Walden North IPP provides as follows:

> The Walden North EPA renewal enables the continued diversion of water from Cayoosh Creek into Seton Lake which allows for additional BC Hydro generation at the Seton Generating Station (Seton GS) and maintains the dilution ratio supportive of fish spawning in the Bridge River system. In the absence of the EPA renewal, alternative arrangements for diversion to Seton Lake would be required and may not be feasible due to cost and environmental considerations.

On page 25 of the Application, BC Hydro provides further specifications of the benefits from Walden North IPP:

- On average, approximately 20 GWh/yr is generated from water diverted through the Cayoosh Diversion Tunnel after consideration of other Bridge River system constraints. A portion of this incremental generation is outside of the freshet season.
- Diversion of Cayoosh Creek water facilitates maintenance of the dilution ratio of Seton River water to Cayoosh Creek water below the Cayoosh confluence which we understand facilitates salmon migration to spawning areas in the Bridge River system, via Seton River and Seton Lake.

On BC Hydro's website, major projects along the Bridge River System are detailed as follows:

> We're [BC Hydro] planning more than 100 major projects in the system, including:
>
> - Generating unit upgrades at Bridge 2
> - Slope drainage improvements
>
> Our Bridge River facilities are between 55 and 70 years old, and need to be updated.

[1] https://www.bchydro.com/energy-in-bc/projects/bridge-river-projects.html

The electricity generated on the system accounts for about 6% of BC Hydro's total generation. These facilities are capable of generating 550 MW of power but are currently restricted to less than 455 MW.

We're spending almost $400 million between 2015 and 2019 to re-power our Bridge River facilities.

1.39.2 According to engineering drawings in Appendix G, are the existing spawning channels that support fish migration at Seton GS insufficient, and if so, please provide possible alternatives and their associated costs to address this issue.

RESPONSE:

Spawning channels are meant for spawning and rearing, and are not used for fish migration. The existing spawning channels are sufficient for this intended purpose as they provide additional habitat for fish beyond that in the Seton River and Cayoosh Creek, and studies have demonstrated that the channels support a number of different fish species and life stages.

39.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: WALDEN NORTH EPA
Exhibit B-1, pp. 6, 25; Appendix G, pp. 1-4

BC Hydro website, Bridge River system upgrades[1]

On page 6 of the Application, BC Hydro states the unique benefits Walden North IPP provides as follows:

> The Walden North EPA renewal enables the continued diversion of water from Cayoosh Creek into Seton Lake which allows for additional BC Hydro generation at the Seton Generating Station (Seton GS) and maintains the dilution ratio supportive of fish spawning in the Bridge River system. In the absence of the EPA renewal, alternative arrangements for diversion to Seton Lake would be required and may not be feasible due to cost and environmental considerations.

On page 25 of the Application, BC Hydro provides further specifications of the benefits from Walden North IPP:

- On average, approximately 20 GWh/yr is generated from water diverted through the Cayoosh Diversion Tunnel after consideration of other Bridge River system constraints. A portion of this incremental generation is outside of the freshet season.
- Diversion of Cayoosh Creek water facilitates maintenance of the dilution ratio of Seton River water to Cayoosh Creek water below the Cayoosh confluence which we understand facilitates salmon migration to spawning areas in the Bridge River system, via Seton River and Seton Lake.

On BC Hydro's website, major projects along the Bridge River System are detailed as follows:

> We're [BC Hydro] planning more than 100 major projects in the system, including:
>
> - Generating unit upgrades at Bridge 2
> - Slope drainage improvements
>
> Our Bridge River facilities are between 55 and 70 years old, and need to be updated.

[1] https://www.bchydro.com/energy-in-bc/projects/bridge-river-projects.html

The electricity generated on the system accounts for about 6% of BC Hydro's total generation. These facilities are capable of generating 550 MW of power but are currently restricted to less than 455 MW.

We're spending almost $400 million between 2015 and 2019 to re-power our Bridge River facilities.

1.39.3 In the absence of the EPA renewal, in table format please provide further information regarding the environmental considerations. In addition, please provide possible alternative arrangements and their associated costs.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.5.1.

39.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: WALDEN NORTH EPA
Exhibit B-1, pp. 6, 25; Appendix G, pp. 1-4

BC Hydro website, Bridge River system upgrades[1]

On page 6 of the Application, BC Hydro states the unique benefits Walden North IPP provides as follows:

> The Walden North EPA renewal enables the continued diversion of water from Cayoosh Creek into Seton Lake which allows for additional BC Hydro generation at the Seton Generating Station (Seton GS) and maintains the dilution ratio supportive of fish spawning in the Bridge River system. In the absence of the EPA renewal, alternative arrangements for diversion to Seton Lake would be required and may not be feasible due to cost and environmental considerations.

On page 25 of the Application, BC Hydro provides further specifications of the benefits from Walden North IPP:

- On average, approximately 20 GWh/yr is generated from water diverted through the Cayoosh Diversion Tunnel after consideration of other Bridge River system constraints. A portion of this incremental generation is outside of the freshet season.
- Diversion of Cayoosh Creek water facilitates maintenance of the dilution ratio of Seton River water to Cayoosh Creek water below the Cayoosh confluence which we understand facilitates salmon migration to spawning areas in the Bridge River system, via Seton River and Seton Lake.

On BC Hydro's website, major projects along the Bridge River System are detailed as follows:

> We're [BC Hydro] planning more than 100 major projects in the system, including:
>
> - Generating unit upgrades at Bridge 2
> - Slope drainage improvements
>
> Our Bridge River facilities are between 55 and 70 years old, and need to be updated.

[1] https://www.bchydro.com/energy-in-bc/projects/bridge-river-projects.html

The electricity generated on the system accounts for about 6% of BC Hydro's total generation. These facilities are capable of generating 550 MW of power but are currently restricted to less than 455 MW.

We're spending almost $400 million between 2015 and 2019 to re-power our Bridge River facilities.

1.39.4 Of the 20 GWh/yr additional downstream generation from the Walden North IPP to Seton GS, what portion of this incremental generation is outside of the freshet season?

RESPONSE:

The 20 GWh/yr of additional downstream generation as identified in the Application was an approximate number. A more accurate value is 24.4 GWh/yr.

Please refer to BC Hydro's response to BCUC IR 1.31.1.1.

39.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: WALDEN NORTH EPA
Exhibit B-1, pp. 6, 25; Appendix G, pp. 1-4

BC Hydro website, Bridge River system upgrades[1]

On page 6 of the Application, BC Hydro states the unique benefits Walden North IPP provides as follows:

> The Walden North EPA renewal enables the continued diversion of water from Cayoosh Creek into Seton Lake which allows for additional BC Hydro generation at the Seton Generating Station (Seton GS) and maintains the dilution ratio supportive of fish spawning in the Bridge River system. In the absence of the EPA renewal, alternative arrangements for diversion to Seton Lake would be required and may not be feasible due to cost and environmental considerations.

On page 25 of the Application, BC Hydro provides further specifications of the benefits from Walden North IPP:

- On average, approximately 20 GWh/yr is generated from water diverted through the Cayoosh Diversion Tunnel after consideration of other Bridge River system constraints. A portion of this incremental generation is outside of the freshet season.
- Diversion of Cayoosh Creek water facilitates maintenance of the dilution ratio of Seton River water to Cayoosh Creek water below the Cayoosh confluence which we understand facilitates salmon migration to spawning areas in the Bridge River system, via Seton River and Seton Lake.

On BC Hydro's website, major projects along the Bridge River System are detailed as follows:

> We're [BC Hydro] planning more than 100 major projects in the system, including:
>
> - Generating unit upgrades at Bridge 2
> - Slope drainage improvements
>
> Our Bridge River facilities are between 55 and 70 years old, and need to be updated.

[1] https://www.bchydro.com/energy-in-bc/projects/bridge-river-projects.html

The electricity generated on the system accounts for about 6% of BC Hydro's total generation. These facilities are capable of generating 550 MW of power but are currently restricted to less than 455 MW.

We're spending almost $400 million between 2015 and 2019 to re-power our Bridge River facilities.

1.39.5 As BC Hydro states that the Bridge River system is undergoing over 100 major projects, in table format, please list the projects that will increase generation from the Bridge River system. In addition, please quantify the increased energy generation and their respective completion dates.

RESPONSE:

BC Hydro notes that the information on its website is outdated and we are in the process of updating with more current information. Although there are over 100 projects planned for the Bridge River system, these are not all major projects.

The major projects planned for the Bridge River system are focused on improving the health of our generating units and returning these units to their historic generating capacity and rating. These major projects and their projected in-service dates are provided in the table below.

In this table we have also indicated which of these projects are restoring capacity to the system back to their historic capacity from current capacity. The estimated generation associated with this restored capacity is 40 GWh per year for Bridge River 1&2 and 54 GWh per year for the La Joie Dam project in an average water year.

Although we are restoring 107 MW of capacity of which 104 MW is attributable to Bridge River 1&2, the gains of 40 GWh per year will mostly be attributed to the Bridge River 2 units 5&6 refurbishment. The remaining capacity gains will provide flexibility with water management and the ability to generate and shape generation in economically beneficial periods.

Investment Planning Description	ISD	Historic Capacity MW	Current Capacity MW
BR1 Strip and Recoat Penstock 1-4 Interior	**11/30/2025**	**-**	**-**
BR1 Replace TransformersT1 & T2	**12/14/2017**	**-**	**-**
BR1 Upgrade U1-U4 Generator/Governor	**01/31/2026**	**200**	**190**
BR2 Units 5 & 6 Upgrade	**07/23/2019**	**150**	**96**
BR1 Electrical Protection Upgrade Project	**1/11/2018**	**-**	**-**
BR2 - Strip and Recoat Penstock 1 Interior	**11/23/2018**	**-**	**-**
BR2 - Strip and Recoat Penstock 2 (U7&8) Interior	**11/30/2020**	**-**	**-**
BR2 Units 7 & 8 Upgrade	**05/31/2021**	**150**	**110**
LAJ - Upgrade Unit Protection and Controls	**8/21/2023**	**-**	**-**
SON - Upgrade Unit	**12/19/2025**	**-**	**-**
SON - Replace Governor	**5/7/2019**	**-**	**-**
LAJ - Dam Improvements	**03/29/2032***	**25**	**22**

39.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: WALDEN NORTH EPA
Exhibit B-1, pp. 6, 25; Appendix G, pp. 1-4

BC Hydro website, Bridge River system upgrades[1]

On page 6 of the Application, BC Hydro states the unique benefits Walden North IPP provides as follows:

> The Walden North EPA renewal enables the continued diversion of water from Cayoosh Creek into Seton Lake which allows for additional BC Hydro generation at the Seton Generating Station (Seton GS) and maintains the dilution ratio supportive of fish spawning in the Bridge River system. In the absence of the EPA renewal, alternative arrangements for diversion to Seton Lake would be required and may not be feasible due to cost and environmental considerations.

On page 25 of the Application, BC Hydro provides further specifications of the benefits from Walden North IPP:

- On average, approximately 20 GWh/yr is generated from water diverted through the Cayoosh Diversion Tunnel after consideration of other Bridge River system constraints. A portion of this incremental generation is outside of the freshet season.
- Diversion of Cayoosh Creek water facilitates maintenance of the dilution ratio of Seton River water to Cayoosh Creek water below the Cayoosh confluence which we understand facilitates salmon migration to spawning areas in the Bridge River system, via Seton River and Seton Lake.

On BC Hydro's website, major projects along the Bridge River System are detailed as follows:

> We're [BC Hydro] planning more than 100 major projects in the system, including:
>
> - Generating unit upgrades at Bridge 2
> - Slope drainage improvements
>
> Our Bridge River facilities are between 55 and 70 years old, and need to be updated.

[1] https://www.bchydro.com/energy-in-bc/projects/bridge-river-projects.html

The electricity generated on the system accounts for about 6% of BC Hydro's total generation. These facilities are capable of generating 550 MW of power but are currently restricted to less than 455 MW.

We're spending almost $400 million between 2015 and 2019 to re-power our Bridge River facilities.

1.39.6 As BC Hydro anticipates an increased annual generation from Site C and heritage site upgrades (2017 BC Hydro Revenue Requirement Application) by 2025, is the diversion and downstream generation from Walden North IPP to Seton GS of 20 GWh/yr necessary for BC Hydro’s energy needs, and if so, please provide further explanation.

RESPONSE:

The diversion of water through the Cayoosh Diversion Tunnel provides additional flows for Seton Dam generation and, also, during the salmon migration period, maintains the dilution ratio to support fish migration. During the salmon migration period, BC Hydro diverts water from Cayoosh Creek to Seton Lake to meet the Bridge-Seton Order dilution targets whether or not such water is used to generate electricity at Seton Generation Station. The energy generated from this water at Seton Generating Station is currently included within BC Hydro's resource stack as part of our heritage energy. If this energy were to be removed from BC Hydro's resource stack, it may need to be replaced sometime in the future.

40.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: WALDEN NORTH IPP REFURBISHMENT
Exhibit B-1, p. 28

On page 28 of the Application, the scope of work on the planned Walden North IPP refurbishments are provided:

> The IPP is planning to undertake certain refurbishments of the Walden North facilities once the Walden North EPA renewal has received Commission acceptance. The refurbishment includes a new sluice gate to manage gravel at the intake and associated work, penstock/manifold recoating, civil upgrades for the powerhouse and tailrace area and the decommissioning of an old penstock. The purpose of the refurbishment is to restore the facility to its original condition, and bring other aspects of the facility to current standards, but not to increase the generating capacity.

1.40.1 Please provide a schedule and completion date for the planned refurbishments at the Walden North facilities, and will the IPP be off-line or operating under capacity during construction?

RESPONSE:

The Walden North IPP has advised BC Hydro of the following:

> **"We had planned to complete the refurbishments during the period between August 2019 and November 2019. However, due to the delay of the regulatory review of the EPA, these dates will not be achieved. Depending upon the timing of the EPA approval, the refurbishments will likely be completed during the period between August 2020 and November 2020. During this period of time, the Walden North Facility will be off-line. Note: the EPA will need to be amended to reflect the revised timing for the refurbishments."**

40.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: WALDEN NORTH IPP REFURBISHMENT
Exhibit B-1, p. 28

On page 28 of the Application, the scope of work on the planned Walden North IPP refurbishments are provided:

> The IPP is planning to undertake certain refurbishments of the Walden North facilities once the Walden North EPA renewal has received Commission acceptance. The refurbishment includes a new sluice gate to manage gravel at the intake and associated work, penstock/manifold recoating, civil upgrades for the powerhouse and tailrace area and the decommissioning of an old penstock. The purpose of the refurbishment is to restore the facility to its original condition, and bring other aspects of the facility to current standards, but not to increase the generating capacity.

1.40.2 If the Walden North IPP will be off-line or under capacity during facility upgrades, how will BC Hydro address the downstream benefits, such as maintaining the dilution ration for salmon migration and spawning, and the additional generation to Seton GS?

RESPONSE:

The Walden North IPP is currently scheduling to be off-line from August to November. Please refer to BC Hydro's response to BCUC IR 1.40.1.

Under BC Hydro's Bridge-Seton Water Use Plan Order we are to make reasonable efforts to target the ratio of Cayoosh Creek water to Seton River discharge between the periods of July 20 to August 31 and September 28 to November 15 of each year. Accordingly, the timing of the Walden North IPP's proposed outage overlaps with the time periods in our Water Use Plan for maintaining the dilution ratio for salmon migration. BC Hydro will be discussing, in due course, with the IPP alternative outage schedules for the IPP's construction work, and whether mitigation measures have been contemplated by the IPP.

41.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: WALDEN NORTH EPA RENEWAL
Exhibit B-1, p. 35

On page 35 of the Application, BC Hydro states, "The Walden North facility will not be decommissioned or decommissioned earlier if the EPA is not renewed."

1.41.1 If the EPA is not renewed, what are Cayoose Creek Power Limited Partnership (CCPLP) intentions for the Walden North facility and the energy generated?

RESPONSE:

The Walden North IPP has advised BC Hydro of the following:

"There is no specific process available in British Columbia to sell the electricity generated by an independent power producer to an offtaker other than BC Hydro under an EPA. In the absence of EPA renewal, one alternative could potentially be to sell the electricity generated to Powerex, a wholly-owned subsidiary of BC Hydro, who would in turn trade that generated electricity on energy markets. This option may not be viable, and therefore no specific studies have been completed to access long-term firm available transmission capacity."

41.0 C. ENGINEERING AND ENERGY RELIABILITY

Reference: WALDEN NORTH EPA RENEWAL
Exhibit B-1, p. 35

On page 35 of the Application, BC Hydro states, "The Walden North facility will not be decommissioned or decommissioned earlier if the EPA is not renewed."

1.41.2 If the Walden North IPP will not be decommissioned regardless of EPA renewed, would BC Hydro still obtain the downstream benefits of dilution ratio for salmon migration and additional generation at Seton GS?

RESPONSE:

Without an EPA and Diversion Agreement, there are uncertainties regarding how the parties will manage water flows in relation to the diversion tunnel. Please also refer to BC Hydro's response to BCUC IR 1.5.1.

42.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: GENERAL EPA RENEWAL STRATEGY
British Columbia Hydro and Power Authority Electricity Purchase Agreement Extension Applications for Armstrong Wood Waste Co-Generation and NWE Williams Lake Wood Waste Facilities proceeding (Biomass EPA Extension), Exhibit B-3, BCUC IR 3.5, 3.7; *Utilities Commission Act* (UCA), section 71 (2.21)(b), Overview of BC Hydro's Energy Procurement Practice dated November 2013[1], p. 2; Final Report on BC Hydro's Energy Procurement Practices dated February 2011[2]

Section 71(2.21)b of the UCA states "an applicable integrated resource plan approved under section 4 of the Clean Energy Act," as an item that the BCUC must consider when determining whether an energy supply contract filed by the authority is in the public interest.

In response to BCUC IR 3.7 in the Biomass EPA Extension proceeding, BC Hydro states that "BC Hydro's current EPA renewal practice may, but will not necessarily, result in obtaining more energy and capacity supply than shown in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application load resource balances (LRB). BC Hydro's plan is to stay within the total IPP cost forecast from the 2013 10-Year Rates Plan."

In response to BCUC IR 3.5 in the Biomass EPA Extension proceeding BC Hydro also states it "assess renewals on an individual basis because alternatives are unknown until negotiations for other EPAs are complete", and that "IPP have indicated they believe that their projects should be free to bid into further acquisition processes on the same basis as any greenfield facility".

On page 2 of the document titled "Overview of BC Hydro's Energy Procurement Process", BC Hydro states that:

> In general, BC Hydro employs three different procurement processes or mechanisms for acquiring electricity from IPPs:
>
> A. Competitive Calls
> B. Standard or Open Offers
> C. Bilateral Arrangements

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1 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 https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/acquiring_power/2011q3/Merrimack-Report.pdf

1.42.1 Please explain how the IPP cost forecast from the 2013 10-Year Rates Plan was established.

RESPONSE:

The public version of this response has been redacted to maintain in confidence commercially sensitive information as public disclosure could impact the commercial interests of our suppliers and ongoing negotiations related to EPA renewals.

The annual IPP cost forecast from the 2013 10-Year Rates Plan was based on the sum of (1) the annual forecast costs of "Existing and Committed EPAs"; and (2) the assumed annual costs of future "EPA renewals" over the period fiscal 2015 to fiscal 2024, and as described further below.

- **<u>Existing and Committed EPAs</u>: BC Hydro forecast the cost by applying the price, as determined in accordance with each EPA, to the forecast volumes. Volumes were forecast based on how long projects have been in commercial operation, as follows:**

  - **<u>Prior to achieving one full fiscal year of commercial operation</u>, BC Hydro forecast the volume of energy based on the contracted energy in the EPA. This amount was adjusted at various stages of the project to account for the three key areas of uncertainty:**

    (i) The likelihood that the IPP will achieve commercial operation;

    (ii) When the IPP will achieve commercial operation; and

    (iii) The volume of energy deliveries from the IPP project once it achieves commercial operation.

    BC Hydro's assessment of these uncertainties was informed by regular communications with the IPPs with respect to their project development and BC Hydro's experience that the actual volume of energy deliveries has historically been lower than the IPP estimate; and

  - **<u>After one full fiscal year of commercial operation</u> and during every subsequent year of the EPA term, generally (e.g., an exception is Island Generation) the average of each IPP project's historical energy deliveries was used to forecast future energy deliveries, with an adjustment to remove non-recurring events.**

- **EPA Renewals: BC Hydro forecast the cost by applying an assumed EPA renewal price to the assumed forecast volumes, with assumptions described below:**

  - **Assumed EPA Renewal Prices: For EPA renewals in the integrated system during BC Hydro's 2013 10-Year Rates Plan, we had assumed a price of [redacted] for run of river projects, [redacted] for storage hydro projects, and [redacted] for biomass projects. These estimates were lower than the original contract prices to reflect that EPA renewals are related to existing projects for which the IPPs initial capital investment has been fully or largely recovered during the term of the initial EPA. In determining these assumed prices, BC Hydro considered the IPP opportunity cost, IPP cost of service (including a rate of return) and BC Hydro's opportunity cost. BC Hydro's review of these benchmarks generally indicated that, on a long-term basis, the IPP cost of service was expected to be above the IPP opportunity cost and below BC Hydro's opportunity cost. The assumed prices were representative of BC Hydro's estimate of the IPP cost of service for the forecast volumes. On average, BC Hydro expected to be able to acquire the forecast volumes at the assumed prices.**

    Accordingly, the prices used for the 2013 10 Year Rates Plan were not "target" prices but were only assumptions used to determine a forecast budget for IPP renewals. Some EPA prices may be higher than the assumed price, and some EPA prices may be lower; and

  - **Assumed EPA Renewal Volumes: BC Hydro's renewal assumptions were consistent with the 2013 IRP Recommended Action 4 and were applied to aggregate energy and capacity volumes rather than to the number of contracts for the applicable bioenergy and run of river IPP projects within BC Hydro's integrated area.**

    For both bioenergy and run of river resources, BC Hydro's renewal assumptions were estimates of the likelihood of being able to renew contracts, at mutually agreeable pricing that is cost effective for BC Hydro, considering that a number of these projects' generating facilities could be 20 years or older at the expiration of their original EPA. Moreover, for biomass, our estimate for these renewals was further informed by our understanding of the reduced long-term certainty of available fibre supply. These assumptions were made using the best information available at the time.

42.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: GENERAL EPA RENEWAL STRATEGY
British Columbia Hydro and Power Authority Electricity Purchase Agreement Extension Applications for Armstrong Wood Waste Co-Generation and NWE Williams Lake Wood Waste Facilities proceeding (Biomass EPA Extension), Exhibit B-3, BCUC IR 3.5, 3.7; *Utilities Commission Act* (UCA), section 71 (2.21)(b), Overview of BC Hydro's Energy Procurement Practice dated November 2013[1], p. 2; Final Report on BC Hydro's Energy Procurement Practices dated February 2011[2]

Section 71(2.21)b of the UCA states "an applicable integrated resource plan approved under section 4 of the Clean Energy Act," as an item that the BCUC must consider when determining whether an energy supply contract filed by the authority is in the public interest.

In response to BCUC IR 3.7 in the Biomass EPA Extension proceeding, BC Hydro states that "BC Hydro's current EPA renewal practice may, but will not necessarily, result in obtaining more energy and capacity supply than shown in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application load resource balances (LRB). BC Hydro's plan is to stay within the total IPP cost forecast from the 2013 10-Year Rates Plan."

In response to BCUC IR 3.5 in the Biomass EPA Extension proceeding BC Hydro also states it "assess renewals on an individual basis because alternatives are unknown until negotiations for other EPAs are complete", and that "IPP have indicated they believe that their projects should be free to bid into further acquisition processes on the same basis as any greenfield facility".

On page 2 of the document titled "Overview of BC Hydro's Energy Procurement Process", BC Hydro states that:

> In general, BC Hydro employs three different procurement processes or mechanisms for acquiring electricity from IPPs:
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2 https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/acquiring_power/2011q3/Merrimack-Report.pdf

C. Bilateral Arrangements

1.42.1.1 Please elaborate on how BC Hydro prioritizes and weighs the IPP cost forecast from the 2013 10-Year Rates Plan, the LRB, and any other considerations in determining whether BC Hydro should continue to renew EPAs with IPPs.

RESPONSE:

This response includes commercially sensitive information which has been redacted in the public version of the response as public disclosure could impact the commercial interests of our suppliers and ongoing negotiations related to EPA renewals.

Our approach to EPA renewals has been informed by Recommended Action 4 from the 2013 IRP. Recommended Action 4 indicates that BC Hydro is to optimize its portfolio according to the key principle of reducing near term costs while maintaining cost-effective options for long-term need.

As stated in BC Hydro's F17-F19 RRA which reflected the most recent 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.

The 2013 IRP includes EPA renewal assumptions; however, these assumptions do not set targets or threshold amounts for the energy and capacity volumes for EPA renewals (by resource type or in aggregate) but were estimates of what BC Hydro assumed at that time would be available for renewal at a cost-effective price. The need for new resources, including EPA renewals, is identified by BC Hydro's LRB. Based on the mid-level load forecast in the F17-F19 RRA, the LRB identifies a need for new resources in fiscal 2022. Implementing the Recommended Actions of the 2013 IRP (i.e., including Site C, DSM, Standing Offer Program, and the assumed energy and capacity volumes from EPA renewals) will defer the need for additional resources until fiscal 2034. In relation to the EPA Renewals, BC Hydro's estimate of its LRMC of energy after fiscal 2034 has been $[redacted]/MWh ($2017) for greenfield IPPs.

BC Hydro generally has assessed each individual IPP project as its EPA approached the end of its contract term; however, for those EPAs that have "evergreen" provisions, BC Hydro has been deferring renewal of EPAs for the smaller hydroelectric projects and focusing on negotiation of EPA renewals with larger hydroelectric projects such as the Akolkolex, Soo River, Boston Bar and Doran Taylor projects which have already been executed and accepted by the Commission.

Given the above, as an EPA for a larger hydroelectric project approached the end of its original contract term, our negotiations with the individual IPP focused on assessing the individual facility and its cost structure and risks, and achieving a cost-effective renewal contract in the context of the key principle of reducing near term costs while maintaining cost-effective options for long-term need (Recommended Action 4 from the 2013 IRP). BC Hydro has been renewing individual EPAs where it has been cost effective to do so and has been guided by the 2013 IRP EPA renewal assumptions.

Renewing an EPA with existing IPP facilities has a number of important benefits. It allows for the continued use of existing reliable assets, which defers the need to develop new resources and associated environmental impacts. EPA renewals generally allow BC Hydro to negotiate lower energy prices given that the initial IPP capital investment has likely been fully or largely recovered during the term of the original EPA. Moreover, renewing the EPAs of existing projects enables continued reliable operation of these facilities, with benefits to the province of B.C., regional districts and local communities.

There may be also other project specific benefits and considerations which may be taken into account, such as the additional benefits provided by these IPPs as outlined on pages 40 and 41 of our Application. Please also refer to BC Hydro's response to BCUC IR 1.1.3 and 1.2.2.

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.

42.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: GENERAL EPA RENEWAL STRATEGY
British Columbia Hydro and Power Authority Electricity Purchase Agreement Extension Applications for Armstrong Wood Waste Co-Generation and NWE Williams Lake Wood Waste Facilities proceeding (Biomass EPA Extension), Exhibit B-3, BCUC IR 3.5, 3.7; *Utilities Commission Act* (UCA), section 71 (2.21)(b), Overview of BC Hydro's Energy Procurement Practice dated November 2013[1], p. 2; Final Report on BC Hydro's Energy Procurement Practices dated February 2011[2]

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In response to BCUC IR 3.7 in the Biomass EPA Extension proceeding, BC Hydro states that "BC Hydro's current EPA renewal practice may, but will not necessarily, result in obtaining more energy and capacity supply than shown in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application load resource balances (LRB). BC Hydro's plan is to stay within the total IPP cost forecast from the 2013 10-Year Rates Plan."

In response to BCUC IR 3.5 in the Biomass EPA Extension proceeding BC Hydro also states it "assess renewals on an individual basis because alternatives are unknown until negotiations for other EPAs are complete", and that "IPP have indicated they believe that their projects should be free to bid into further acquisition processes on the same basis as any greenfield facility".

On page 2 of the document titled "Overview of BC Hydro's Energy Procurement Process", BC Hydro states that:

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C. Bilateral Arrangements

1.42.2 In consideration that BC Hydro's current strategy may result in BC Hydro obtaining more energy and capacity from IPPs than planned in its LRB, please discuss how BC Hydro's current renewal strategy is in the public interest.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.42.1.1 which describes the approach BC Hydro has taken to EPA renewals.

42.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: GENERAL EPA RENEWAL STRATEGY
British Columbia Hydro and Power Authority Electricity Purchase Agreement Extension Applications for Armstrong Wood Waste Co-Generation and NWE Williams Lake Wood Waste Facilities proceeding (Biomass EPA Extension), Exhibit B-3, BCUC IR 3.5, 3.7; *Utilities Commission Act* (UCA), section 71 (2.21)(b), Overview of BC Hydro's Energy Procurement Practice dated November 2013[1], p. 2; Final Report on BC Hydro's Energy Procurement Practices dated February 2011[2]

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2 https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/acquiring_power/2011q3/Merrimack-Report.pdf

C. Bilateral Arrangements

1.42.3 Please discuss the available options for BC Hydro to enter into EPAs with IPPs, including competitive calls, standard or open offers, and bilateral agreements. For each option, please describe the process and explain the pros and cons in the current environment.

RESPONSE:

In general, BC Hydro has used the following procurement processes or mechanisms to enter into EPAs with IPPs: competitive calls, standing offers and bilateral negotiations.

<u>Competitive Calls</u>. Competitive calls are typically initiated through a formal Call for Tenders or Request for Proposals. BC Hydro's competitive calls have been aimed at yielding a pre-established target of incremental electricity generation. Proponents are invited to submit bids by a pre-established deadline and in accordance with pre-established project eligibility criteria (e.g., clean and renewable resource criteria), which vary across competitive calls.

Each bid is reviewed for conformity with bid requirements and project eligibility criteria. BC Hydro assesses conforming, eligible bids for project viability, including the financial strength of the proponent, technical feasibility of the project and long-term viability of the proposed fuel or energy source. Among those proposals that successfully pass the initial conformity and risk assessment reviews, contracts are awarded to the proponents offering the best value in terms of lowest energy prices and best product attributes provided by the project (e.g., the generator is close to load center, hourly firm energy deliveries).

Competitive calls are an attractive option as it drives competition amongst a large pool of potential bidders. However, they can be time-intensive and extensive processes, and do not allow for flexibility in negotiations.

<u>Standing Offers</u>. A standard or open offer allows any IPP with a project that meets the published eligibility criteria to submit an application to the program. Generally, the timing of an application is at the proponent's discretion with no prescribed timelines. The price to be paid for electricity to be purchased from an eligible project, and the EPA terms and conditions, are published in advance.

Standing offer programs are intended to provide a more efficient process for projects with a simplified contract and contract administration; however, there is no price competition and the process does not allow for flexibility in negotiations.

Bilateral Negotiations. BC Hydro has also negotiated EPAs on a bilateral basis. For example, this type of procurement has been used for the renewal of pre-existing EPAs, for opportunities associated with power projects that are already contracted to BC Hydro, and for complex or unique transactions where customized negotiations and contracts are necessary. To ensure bilaterally negotiated EPAs are cost effective, BC Hydro has relied on price benchmarks based on energy prices in recent competitive calls, as well as other benchmarks which may be comparable.

Although bilateral negotiations allow for flexibility in negotiations, there is no price competition amongst bidders and there is less public transparency in the process.

Please also refer to Appendix 2 of BC Hydro's "Overview of BC Hydro's Energy Procurement Practice" dated November 2013 as provided at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/energy-procurement-practices.pdf

42.0 D. GENERAL EPA RENEWAL STRATEGY

Reference: GENERAL EPA RENEWAL STRATEGY
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In February 2011, Merrimack Energy Group, Inc. issued a Final Report on BC Hydro's Energy Procurement Practices.

1.42.4 Please discuss the applicability of the report by Merrimack Energy Group in the current environment.

RESPONSE:

The objective of the evaluation conducted by the Merrimack Energy Group in 2011 was to (i) assess BC Hydro's procurement practices at that time and to identify areas for improvement; and (ii) assess how those practices compared to well-respected procurement practices elsewhere in the utility community and whether improvements could be made to achieve "best in class" performance. This evaluation was done at a time, prior to the 2013 IRP, when BC Hydro was actively engaged in acquiring new resources from new IPP projects.

As BC Hydro, at this time, is not actively acquiring new resources (other than a small number of new First Nations energy projects and some EPA renewals), the Merrimack report is of limited applicability.

Recommendation 6 of the Merrimack report is applicable in that it recommends to BC Hydro to "[d]evelop standards for evaluating and negotiating bilateral contracts and make the standards transparent to stakeholders." In response, and to be transparent, BC Hydro set out its standards for evaluating and negotiating bilateral contracts on page 10 of the "Overview of BC Hydro's Energy Procurement Practice" dated November 2013. This document is posted on the weblink included in the preamble above and these standards for bilateral arrangements have been applied by BC Hydro in relation to our EPA renewals for these hydro IPP projects.

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In February 2011, Merrimack Energy Group, Inc. issued a Final Report on BC Hydro's Energy Procurement Practices.

1.42.4 Please discuss the applicability of the report by Merrimack Energy Group in the current environment.

1.42.4.1 If the report remains applicable, please discuss whether, if so how, BC Hydro's current procurement process has addressed the weaknesses and suggestions contained in the report.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.42.4.

1 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/energy-procurement-practices.pdf

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British Columbia Hydro and Power Authority Electricity Purchase Agreement Extension Applications for Armstrong Wood Waste Co-Generation and NWE Williams Lake Wood Waste Facilities proceeding (Biomass EPA Extension), Exhibit B-3, BCUC IR 3.5, 3.7; *Utilities Commission Act* (UCA), section 71 (2.21)(b), Overview of BC Hydro's Energy Procurement Practice dated November 2013[1], p. 2; Final Report on BC Hydro's Energy Procurement Practices dated February 2011[2]

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C. Bilateral Arrangements

1.42.5 Please discuss whether BC Hydro will conduct another analysis on its energy procurement process in preparation for its upcoming Integrated Resource Plan.

RESPONSE:

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.