BC Hydro
Power smart

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September 29, 2017

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: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Site C Inquiry – Round 2 Information Responses

BC Hydro writes to provide responses to a number of the questions set out in the Commission's Preliminary Report issued on September 20, 2017. The Commission specified a due date of October 4, 2017 and also requested that we endeavor to provide answers as they become available.

Our approach has been to number all of the requests in the Preliminary Report starting with BCUC IR 2.1 (representing the first question in the second round of questions the Commission has posed to BC Hydro). The responses enclosed with this letter are non-sequential, as we are providing responses as soon as they become available.

In the event the Commission requires clarification of any of these responses, we would be pleased to do that. We will forward the next batch of responses as soon as they are available.

For further information, please contact Fred James at 604-623-4317 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

fj/af
Enclosure

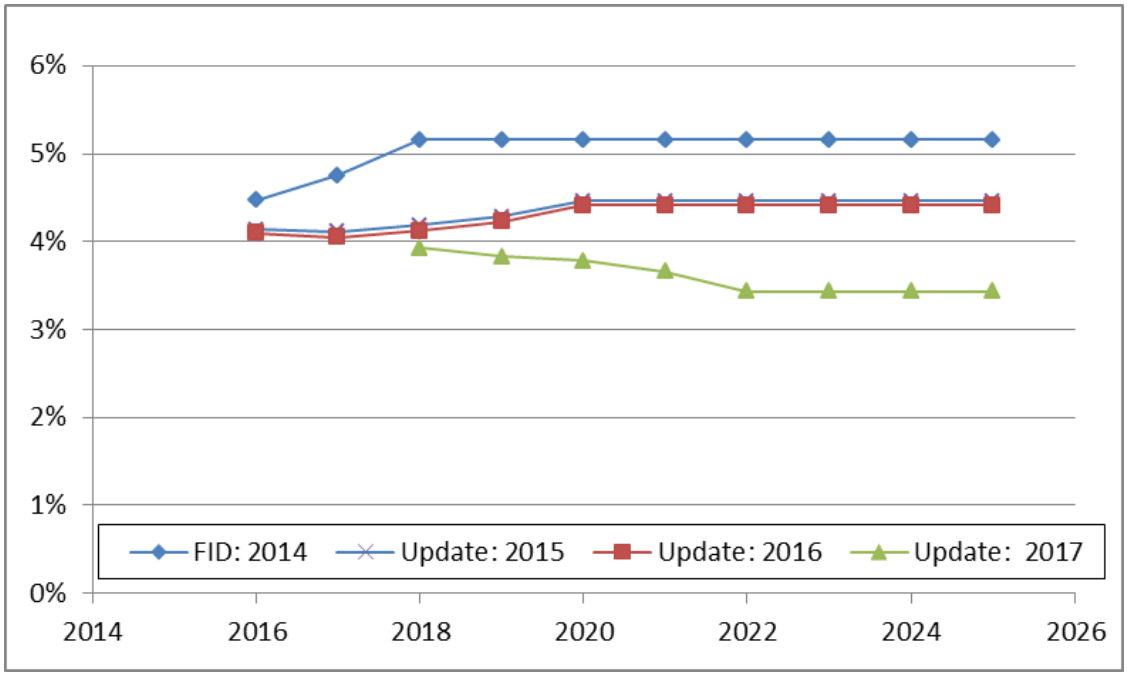
12.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 33

2.12.0 The Panel asks BC Hydro to provide an analysis of the $315 million that has been identified as savings on forecast interest during construction, indicating what effect a rise of 0.5 percent, 1 percent or 2 percent in interest rates would have on the amount of the savings.

RESPONSE:

As reported on page 31 of BC Hydro's August 30 Filing, lower forecast interest rates have resulted in expected savings in interest during construction of approximately $315 million. The savings reflect both the reduction in forecast rates of interest during construction and changes in the expected timing of expenditures.

The chart below presents the changes in forecast interest during construction rates, comparing forecast rates at Final Investment Decision, 2015, 2016 and 2017. Table 4 on page 31 of BC Hydro's August 30 Filing shows the impact on the Site C capital cost associated with each of these interest during construction rate changes.



The table below presents the impact of a specified increase in market interest rates (0.5 per cent, 1 per cent or 2 per cent) on BC Hydro's forecast rates of Interest-During-Construction. The impact of future increases in market interest rates on project costs is mitigated by the amount of long-term debt already issued or hedged. BC Hydro has hedged approximately 50 per cent of forecast long-term debt issuances during the 10 Year Rates Plan. The column at the far right presents the estimated increase in interest cost for the Site C Project relative to the applicable increase in market rates.

	Forecast rate of Interest During Construction					Increase in Site C Interest During Construction ($ million)
	F2018 (%)	F2019 (%)	F2020 (%)	F2021 (%)	F2022-F2025 (%)	
Forecast Interest During Construction Rate (current)	3.93	3.83	3.78	3.66	3.43	0
Change in Market Interest Rates:						
Impact of +0.5% interest rates	+0.07	+0.08	+0.10	+0.12	+0.14	32
Impact of +1.0% interest rates	+0.15	+0.17	+0.21	+0.23	+0.28	65
Impact of +2.0% interest rates	+0.30	+0.35	+0.44	+0.48	+0.58	136

BC Hydro has recently entered into additional interest rate hedges in fiscal 2018 relating to its future debt requirements and is planning on placing further interest rate hedges before the end of fiscal 2018, which are not reflected in the $315 million of interest savings already identified.

Hedging future debt requirements reduces interest rate risk and the impact to project costs of future interest rate increases. As the additional interest rate hedges that BC Hydro entered into in fiscal 2018 were at lower interest rates than previously forecast, this will help to minimize interest during construction costs for the Site C project.

26.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 86

2.26.0 The adder for "Adjustment for Delivery to Lower Mainland and annual shape adjustment" appears to be derived from three input parameters: "Locational Adjustments (CIFT)", "Locational Adjustments (Line Losses)", and "Firm Energy Adjusters".

BC Hydro is requested to explain in more detail the assumptions and calculations used to determine the values of these three input parameters.

RESPONSE:

As discussed in both section 5.6 of BC Hydro's August 30 Filing and in the response to BCUC IR 2.45.0, Portfolio PV Analysis is BC Hydro's preferred approach to making resource acquisition decisions. BC Hydro uses Unit Energy Costs (UEC) to provide a simplified metric to help explain the results of Portfolio PV Analysis.

The three referenced input parameters to the UEC adjustments are provided in BC Hydro's response to BCUC IR 1.2.0 Attachment 3[1] and are derived from four (of eight) adjusters that are described in our 2013 Integrated Resource Plan, Appendix 3A-34, "Firm Energy Cost Adjustments"[2], under the following headings:

Heading in BC Hydro's response to BCUC IR 1.2.0 Attachment 3	**Heading in 2013 Integrated Resource Plan**
Firm Energy Adjusters	1. Freshet Firm Energy Adjustment
	2. 3 x 12 Time of Delivery Price Adjustment
Locational Adjustments (CIFT)	3. Cost of Incremental Firm Transmission (CIFT)
Locational Adjustments (Line Losses)	4. Line Losses Adjustment

In general, the UEC adjusters described in the 2013 Integrated Resource Plan are used to facilitate high level resource comparisons reflecting the cost of the resource in meeting system needs at a common place of delivery. The adjustment

[1] **On the "Sheet C Lower Mainland adj" worksheet.**

[2] **https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0300a34-nov-2013-irp-appx-3a-34.pdf.**

process is similar to our approach taken in bid evaluation during our acquisition call processes which considers two key inputs:

- **<u>IPP bid prices</u> that reflect call terms such as the requirement to deliver firm energy; limits on freshet firm energy deliveries; and premiums for the time of energy delivery. Bid prices are calculated such that the total revenue of the project using the firm price (for the firm energy) and a non-firm price (for the non-firm energy) would equal the annual levelized resource option revenue desired from BC Hydro to cover the cost and a desired rate of return; and**

- **<u>Additional BC Hydro costs</u> that reflect incremental costs that may be incurred by BC Hydro to meet system need and deliver the acquired energy to the Lower Mainland. These costs include the cost of incremental firm transmission and losses.**

A modified description of the four adjusters from the 2013 Integrated Resource Plan is provided below with updates to reflect our current assumptions:

1. **<u>Freshet Firm Energy Adjustment</u>: Additional energy in the freshet period (May through July) has limited value to the BC Hydro system. This is a result of high freshet inflows into BC Hydro reservoirs which limit the capability of the system to absorb additional energy combined with low system need and depressed prices in the Pacific North West electricity markets during that time. The amount of firm energy from a resource option during the freshet is limited to 25 per cent of the total firm energy for the year. The 25 per cent reflects the fact that the May-July freshet period represents 25 per cent of the year. Any excess freshet energy is deemed to be non-firm.**

2. **<u>3 x 12 Time of Delivery Price Adjustment</u>: Energy that is delivered to the system has a different value to meeting system need depending on when it is generated. Our "3X12 Time of Delivery" factors indicate how this value changes for different periods in each day (super peak hours, peak hours and off peak hours)[3] for each month of the year. The factors in the table below depict monthly adjustments to a resource option's price based on the period in which the energy is delivered. For example, an option that delivers energy in super-peak hours in January is valued at 123 per cent of its annual average cost.**

   These factors are derived from the monthly and daily shape of the "NW-Mid-C" electricity price forecast provided in Table B-2 of ABB's spring

[3] **The Super-Peak period is from hours 16:00 to 20:00, and the Peak period is from 6:00 to 16:00 and from 20:00 to 22:00 from Monday to Saturday. The Off-Peak period is from 22:00 to 6:00 from Monday to Saturday and includes all hours on Sundays and B.C. statutory holidays.**

2016 Power Reference Case report. The ABB Group's Power Reference Case report is confidential and provided for the sole use of subscribers. ABB Group's Power Reference Case report was provided on a confidential basis to the Commission in the F2017-F2019 RRA (refer to BC Hydro's response to BCUC IR 2.310.1 in that proceeding).

	Super Peak Hours (%)	Peak Hours (%)	Off Peak Hours (%)
January	123	116	115
February	115	103	106
March	107	98	99
April	98	80	89
May	88	73	82
June	86	74	81
July	104	96	99
August	116	107	105
September	114	97	98
October	111	98	100
November	118	107	110
December	124	115	116

3. **<u>Cost of Incremental Firm Transmission (CIFT)</u>: BC Hydro may incur additional bulk transmission reinforcement costs as a result of acquiring additional system capacity that may need to be delivered to the Lower Mainland. For UEC adjustments we calculate a cost of incremental firm transmission using the attached BC Transmission Corporation (BCTC) report titled: Bulk Transmission System Cost of Incremental Firm Transmission for BC Hydro's 2008 LTAP Base Plan and Contingency Resource Plans CRP1 and CRP2 (January 15, 2009). The calculation is based on the location of the resources and their generation characteristics. This report provides a general indication of the long-term unit cost of bulk transmission system reinforcements from one transmission region to the next. Note that in portfolio analysis CIFT is not used, rather specific transmission upgrade requirements and their associated costs are modeled in the portfolio analysis. This provides a more granular assessment of potential transmission requirements.**

4. **<u>Line Losses Adjustment</u>: A calculation was carried out to determine the losses associated with delivering energy of each resource option to the Lower Mainland. The calculation is based on the location of the resources and their generation characteristics. Energy losses were calculated based on the methodology described in the attached BCTC report titled: Peak**

Load Incremental Losses for the Bulk Transmission System (January 2010).

It should be noted that these UEC adjusters do not reflect risks and uncertainties related to the level of study upon which resource option information is based, resource technology, earliest in-service date, and resource costs.

27.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 86

2.27.0 BC Hydro is requested to explain in more detail how the specific amount for "Capacity Credits" was calculated/determined, if they are related to the increase in capacity from 1100MW to 1132.2MW or 1145MW, and why they are included in this spreadsheet.

RESPONSE:

The "Capacity Credit" adjuster was left in the spreadsheet provided as it was part of the template, but was not used in our August 30 Filing.

BC Hydro's August 30 Filing made cost comparisons through the preparation of a block unit energy cost for similar levels of energy and dependable capacity. This "Block UEC Analysis" is described in section 5.6 of our August 30 Filing.

In the event the Commission wishes to understand the calculation despite it not being used in our August 30 Filing, we provide the calculation method here. The capacity credit is unrelated to the change in Site C generating capacity.

The "Capacity Credit" for Site C in Attachment 3 was calculated using the outdated dependable capacity of 1,100 MW and annual energy of 5,100 GWh and is based on the following calculation:

$$\boldsymbol{Capacity\ Credit} = \frac{\boldsymbol{Dependable\ Capacity \times Capacity\ Long\ Run\ Marginal\ Cost}^{1}}{\boldsymbol{Annual\ Energy}}$$

$$= \frac{\mathbf{1,100}\ \boldsymbol{MW} \times \frac{\$\mathbf{50}}{\boldsymbol{kW-yr}}}{\mathbf{5,100}\ \boldsymbol{GWh}}$$

$$= \frac{\$\mathbf{11}}{\boldsymbol{MWh}}$$

[1] **As described in Table L-2 of Appendix L to our August 30 Filing, we use the cost of Revelstoke Unit 6 in the capacity credit adjustment for general project unit energy cost comparisons; however, when comparing Site-C to an alternative portfolio, Revelstoke Unit 6 is built in both portfolios and the marginal capacity resource is pumped storage, as provided in section 5.6 of our August 30 Filing.**

28.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 86

2.28.0 BC Hydro is to explain in detail how these annual amounts for both of these direct inputs were calculated from the sunk and termination costs reported elsewhere in BC Hydro's report. Please also comment on the appropriateness of these adders to the UEC given the definition of UEC that the Panel has adopted.

RESPONSE:

The annual amounts shown for the sunk and termination costs used in the UEC calculation (provided in BC Hydro's response to BCUC IR 1.2.0 Attachment 3[1]) were based on the values provided in Table 13 in section 6.2 of our August 30 Filing with interest charges and an assumed ten-year recovery from rates beginning in fiscal 2020. The basis for the annual values with specific references to the values in Table 13 is described further below.

Please refer to BC Hydro's response to BCUC IR 2.45.0 for a discussion on the use of UECs and the need to utilize portfolio analysis for a complete picture. The Commission adopted the UEC definition "Unit Energy Cost simply expresses the cost for a resource by its levelized annual cost per unit of energy produced". It was appropriate to reflect these adjustments in the Block UECs shown in section 5.6 of our August 30 Filing because the sunk and termination costs will need to be recovered from ratepayers in the event that the Project is terminated and the UEC shown was the incremental commitments needed to complete the Project.

These adjustments can be considered as either:

- **A sunk or committed cost reducing the costs needed to complete Site C; OR**
- **An additional cost to the Clean Alternative Block if Site C were to be terminated.**

One of these approaches must be adopted otherwise the analysis does not account for the significant costs spent to date and the costs of termination and site remediation. We chose to put it as an avoided cost on the Site C UEC rather than as an additional cost on the Clean Alternative Block to allow the comparison of the Site C cost to the current market electricity price forecast (please refer to

[1] **The sunk costs and sunk plus termination costs are provided on row 58 of the "Sheet E UEC (Sunk)" and "Sheet F UEC (Sunk + Term)" worksheets, respectively.**

section 5.6.2 of our August 30 Filing) and to allow others to develop their own alternative blocks of resources for comparison.

<u>Sunk Costs on “Sheet E UEC (Sunk)” Worksheet</u>

The sunk costs are based on $2.1 billion at December 31, 2017 (shown as the sum of “Cost Category” items #1 and #2 in Table 13 on pages 72 to 73 of our August 30 Filing), which will increase with interest until the end of fiscal 2019, to the total of $2.2 billion.

We then assume to recover this $2.2 billion through rates over a ten-year period beginning at the start of fiscal 2020 with finance charges calculated using BC Hydro’s weighted average cost of debt.

<u>Sunk Costs plus Termination Costs on “Sheet F UEC (Sunk + Term)” Worksheet</u>

The sunk costs PLUS termination costs are based on $3.0 billion at December 31, 2017 (shown as sum of “Cost Category” items #1, #2, #3 and #4 in Table 13 on pages 72 to 73 of our August 30 Filing), which will increase with interest until the end of fiscal 2019, to the total of $3.2 billion. This increase is described in the last bullet on page 73 of our August 30 Filing.

We then assume to recover this $3.2 billion through rates over a ten-year period beginning at the start of fiscal 2020 with finance charges calculated using BC Hydro’s weighted average cost of debt.

29.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 87

2.29.0 BC Hydro is requested to explain why that adjustment has not been made.

RESPONSE:

BC Hydro does not include the project reserve in our calculation of unit energy cost because BC Hydro cannot access this reserve without approval from Treasury Board.

31.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 87

2.31.0 The Panel finds that if Mikisew Cree First Nation is correct in its submissions relating to either the potential downstream impacts on the PAD (Peace Athabasca Delta) or litigation relating to potential treaty infringements of Site C then this could impact the costs to Site C and ratepayers, and therefore result in an upward adjustment of the UEC for Site C energy. The Panel is unclear how, or whether, this is a direct cost to ratepayers. It appears to the Panel that this is a cost that would be borne by taxpayers. We invite further comment on this issue.

RESPONSE:

In its submission to the Commission, the Mikisew Cree First Nation (Mikisew Cree) state that the "downstream effects on the Peace Athabasca Delta were improperly scoped out of the Joint Review Panel process".[1] This is not correct. The effects of the Project on the Peace Athabasca Delta (PAD), which is about 1,100 km downstream from the dam site, were considered as part of the environmental assessment by experts in river processes and the Joint Review Panel, and no effects were found.[2] As noted by the Commission in its Interim Report, the inquiry "is not a reconsideration of decisions made in the environmental assessment process".[3]

BC Hydro consulted at length with Mikisew Cree and Athabasca Chipewyan First Nations on this issue, and provided funding so they could retain their own consultant to review the studies and submit their own reports.[4] The Joint Review Panel devoted two hearing days to downstream effects at which BC Hydro presented a panel of pre-eminent academics and experts.[5] Scientists from Parks

[1] **Mikisew Cree First Nation's submission to the Commission Site C Inquiry, F84-1, page 7.**

[2] **Technical Memo: Peace Athabasca Delta, CEAR#1546, found at: http://www.ceaa.gc.ca/050/document-eng.cfm?document=93686; BC Hydro's Response to "Impacts of the Proposed Site C Dam on the Hydrologic Recharge of the Peace-Athabasca Delta" (Carver 2013), CEAR#2215, found at http://www.ceaa.gc.ca/050/documents/p63919/97196E.pdf; Joint Review Panel Report, section 3.7, pages 35 to 42.**

[3] **Commission Interim Report, page 7, section 3.2.5.**

[4] **A summary of the consultation with Mikisew Cree from 2007 to May 2013 is found at EIS Volume 5 Appendix A18, Parts 2 and 2A; Mikisew Cree, together with Athabasca Chipewyan, submitted as part of the environmental assessment, a total of five technical reports on downstream effects; two traditional knowledge reports each; and, extensive closing submissions to the Panel (Refer to CEAR#1814).**

[5] **Joint Review Panel hearing transcripts, January 10, 2014 and January 11, 2014 (for Aquatic and Downstream Environment), found at CEAR#2399, http://www.ceaa.gc.ca/050/documents/p63919/97612E.pdf and CEAR#2420, http://www.ceaa.gc.ca/050/documents/p63919/97670E.pdf.**

Canada and Environment Canada also presented, and agreed with BC Hydro.[6] Mikisew Cree elders, harvesters, and consultants also participated at length.[7] In its report, the Joint Review Panel concluded:

> **"The Panel concludes there would be no effects from the Project on any aspect of the environment in the Peace Athabasca Delta, and a cumulative effects assessment on the PAD is not required."[8]**

Environment Canada confirmed the Joint Review Panel's conclusion was reasonable.[9]

Mikisew Cree, together with Athabasca Chipewyan, challenged the Joint Review Panel's finding in Federal Court, but they withdrew that challenge upon reaching agreements with BC Hydro and Canada that:

(a) BC Hydro would include Mikisew Cree and Athabasca Chipewyan as part of the implementation of its monitoring of downstream effects of the Project (pursuant to condition 6 of the Decision Statement);[10] and

(b) The federal Department of Environment and Parks Canada would meet with Mikisew Cree and Athabasca Chipewyan to explore the viability of establishing a multi-stakeholder technical committee to define the ecological flow needs required to achieve environmental and traditional use objectives in the PAD.[11]

Given that the extensive environmental assessment demonstrated the Project will not impact the PAD, the costs listed by Mikisew Cree in its submission and cited by the Commission Panel (at pages 85 and 86) are not costs that will be borne at all.

[6] **Joint Review Panel hearing transcript, January 10, 2014 (General Hearing), CEAR#2346, found at http://www.ceaa.gc.ca/050/documents/p63919/97503E.pdf; Letter from Steven Wright (Environment Canada) to Ian Chatwell (Transport Canada), re Potential Downstream Effects, June 21, 2013 (CEAR#1476); Environment Canada's written submissions to Joint Review Panel, November 25, 2013 (CEAR#1843); Written submission from Parks Canada, November 24, 2013 (CEAR#1838).**

[7] **Dr. Martin Carver filed five reports on behalf of Mikisew Cree/Athabasca Chipewyan, found at CEAR#1814; Joint Review Panel hearing transcripts, January 10, 2014, January 11, 2014 (for Aquatic and Downstream Environment), found at CEAR#2399, http://www.ceaa.gc.ca/050/documents/p63919/97612E.pdf and CEAR#2420, http://www.ceaa.gc.ca/050/documents/p63919/97670E.pdf; Joint Review Panel hearing transcript, January 10, 2014 (General Hearing), CEAR#2346, found at http://www.ceaa.gc.ca/050/documents/p63919/97503E.pdf.**

[8] **Joint Review Panel Report, page 42.**

[9] **Memorandum from Canadian Environmental Assessment Agency to Minister of Environment, September 8, 2014, page 3.**

[10] **Agreement between Mikisew Cree and Athabasca Chipewyan First Nations and BC Hydro, dated July 16, 2015.**

[11] **Agreement between Mikisew Cree and Athabasca Chipewyan First Nations and Canada, dated July 16 and 17, 2015.**

With respect to the suggestion that "the Site C facility constitutes an unjustified infringement of the Treaty 8 rights of certain First Nations",[12] the majority of the First Nations in closest proximity and most impacted by the Project have entered impact and benefit agreements with BC Hydro, agreeing they do not oppose the Project.[13] Two First Nations, West Moberly and Prophet River, challenged the federal and provincial environmental assessment approvals on the basis the Project unjustifiably infringed their treaty rights. Those challenges were dismissed at first instance and on appeal, and no appeals remain. As early as 2015, both the BC Courts and Federal Courts[14] have noted that it remains open for these First Nations to bring an action for treaty infringement, but to date, they have elected not to do so.

Accordingly, the suggestion that these factors "could impact the costs to Site C and ratepayers, and therefore result in an upward adjustment of the UEC for Site C energy" lacks foundation.

[12] **Commission Interim Report, page 85.**

[13] **BC Hydro has entered agreements with six Treaty 8 First Nations (Doig River, Halfway River, McLeod Lake, Saulteau, Duncan's and Dene Tha') of the ten groups identified as potentially impacted by the Project.**

[14] ***Prophet River First Nation et al v. Attorney General of Canada et al,* 2015 FC 1030; appeal dismissed 2017 FCA 15, leave to appeal to the SCC refused June 29, 2017; *Prophet River First Nation v. British Columbia (Environment)*, 2015 BCSC 1682, appeal dismissed 2017 BCCA 58, leave to appeal to the SCC refused June 29, 2017.**

32.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 92

2.32.0 We request that BC Hydro explain all assumptions made in its analysis of the UEC for the alternative portfolio.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.45.0.

38.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 92

2.38.0 BC Hydro is requested to explain why it selected 4% for an inflation adjustment.

RESPONSE:

The 4 per cent inflation adjustment was calculated to adjust our 2015 resource options costs in F2015 dollars to the cost shown in the Site C submission in F2018 dollars. The inflation over that period was about 4 per cent and was calculated based upon annual inflation figures of 0.9 per cent, 1.0 per cent, 2.0 per cent for 2015, 2016 and 2017. The actual Stats Canada seven city Non-Residential composite[1] was used for 2015 and 2016 and 2 per cent was forecast for 2017.

[1] http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/econ144e-eng.htm.

39.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 92

2.39.0 Please explain why the $105/MWh appears to be based on the weighted average of only the first 8 projects listed in the portfolio.

RESPONSE:

The $105/MWh was based on the weighted average cost of the first eight wind projects. Those projects were selected because they were the lowest cost projects identified by BC Hydro in its resource options wind assessment that in total are capable of generating 5286 GWh/year (approximating Site C's output). The additional energy required to make up the energy loss from pumped storage was provided by the other two wind projects and those costs are reflected in the "Energy Cost" component of the "PS Capacity Adder".

45.0 45. Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 103

2.45.0 BC Hydro is requested to clarify which portfolio(s) were used in its alternate portfolio UEC calculation.

RESPONSE:

Note that this also responds to BCUC IR 2.32.0, which requests all assumptions associated with the Alternative Portfolio Block UEC calculation.

<u>Block UEC</u>

It is useful to provide some context regarding the Block UECs described in section 5.6 of our August 30 Filing, what information those Block UECs provide (and don't provide), and how they relate to the portfolio analysis as described in section 5.5 and with the sensitivity analyses set out in section 8.

BC Hydro's main tool to compare resources is a portfolio present value cost analysis, and not Block UECs. This was described in our August 30 Filing in section 5.5: "Portfolio present value cost analysis (Portfolio PV Analysis) is BC Hydro's main tool to compare resource options, and is standard utility practice for resource planning."[1]

The use of simplified Block UEC analysis provides assistance in explaining the results of the Portfolio PV Analysis.[2] A simplified Block UEC has the advantage of being easy to relate to in relation to the cost of a single resource, but is not able to account for a number of factors, including, for example,

- **the timing of when resource are required;**
- **the value of surpluses in the electric system as difference resources are built;**
- **the relative value of a resource in the context of seasonal and daily market prices; and**
- **how well the particular resources meet the timing and shape of the load.**

It is also important to recognize that resources that may appear to be "alternatives" to Site C, but are not because they would be built whether or not

[1] **August 30 Filing, section 5.5, page 60, lines 5 to 7.**
[2] **August 30 Filing, section 5.6, page 60, lines 20 to 22.**

Site C is completed, are not incorporated into the Block UEC analysis. This includes:

- **A significant amount of DSM (consistent with DSM Option 2) that is very cost effective but limited by the ability to ensure its delivery; and**
- **Revelstoke Unit 6.**

The Block UEC analysis in section 5.6 shows the cost differences for those resources that are not in the Site C portfolio but are in a portfolio without Site C (i.e., truly alternative resources). Those resources are a number of wind and pumped storage projects. The Block UEC does not, and was not intended to, account for all of the differences that can be reflected in a Portfolio PV Analysis, and as a result do not align directly with any of the portfolio runs shown in Section 8.

In Exhibit 29-6, BCSEA's comments on the Commission's Preliminary Report, counsel for BCSEA does a good job of characterizing the benefits of utilizing portfolio PV analysis versus UEC analysis.

<u>Portfolio Analysis and UECs</u>

Site C is not a solution to B.C.'s future energy needs on its own. Site C provides a significant amount of clean, firm energy with dependable capacity, but it must be combined with other resources to meet our future needs. What the portfolio analyses show is the group of resources that would likely be built in a world with Site C (portfolios with Site C), versus what would likely be built in a world without Site C (portfolios without Site C).

BC Hydro interprets the BCUC IRs 2.46.0, 2.47.0 and 2.48.0 as requesting UEC analysis that recognizes the above factors. Given that the simplified Block UEC analysis is unable to account for the same details as a portfolio, BC Hydro has translated the portfolio costs used to calculate the PV differentials into Portfolio UEC values. These Portfolio UECs represent the net present cost of resources added to a portfolio (inclusive of timing to add resources, costs of resources, and trade impact of adding resources) divided by the net present volume of energy generated. The resource prices in these portfolio UECs include supply side resources as well as demand side resources.

The Portfolio UEC results are shown in the following table. As shown, in all sensitivity scenarios, the UEC of the portfolio with Site C is lower than the UEC of the alternative portfolio meaning that ratepayers are better off with continuing construction of Site C as compared to termination. BC Hydro will provide the same portfolio PV and portfolio UEC results for additional sensitivity scenarios requested by the Commission in future IR responses.

Table Sensitivity Analysis: Summary

Sensitivity Input Assumptions	Benefit vs Termination ($ billion present value)	Portfolio UEC with Site C ($/MWh)	Portfolio UEC without Site C ($/MWh)
Base Case – Expected Load and Available	7.3	76	110
Project Cost Sensitivities			
Budget plus Project Reserve of $440 million	7.1	77	110
Budget plus Project Reserve of $440 million, plus 10% increase to total costs	6.8	78	110
Termination and Suspension Costs Less 35%	7.0	76	109
Termination and Suspension Costs plus 100%	8.1	76	114
Load Sensitivities			
Small Gap – Low Load Forecast, Low DSM	6.4	36	65
Base Case Less LNG Loads	6.7	42	73
Large Gap – High Load Forecast, Low DSM	10.6	129	158
Add Low Carbon Electrification section 5.2.3	11.1	144	164
Alternative Resource (Cost and Availability) Sensitivities			
IPP Costs -15% Reduction	6.2	74	103
Base Case with Additional DSM	6.9	69	113
Base Case with Max 7% Gas	6.8	74	106
Market Price Sensitivities			
30% Higher Returns in the Market For Site C	7.6	76	110
Low Electricity Market Price Scenario	7.1	78	111

What these Portfolio UEC results show is:

- **The underlying cost of individual resources is necessarily somewhat masked by the other resources that are built into the portfolio. The UEC of the Site C portfolio is the UEC of all resources and not just Site C. This is why the UEC of the Site C portfolio changes in sensitivity scenarios;**

- **Reducing costs in sensitivities like IPP costs reduces both portfolios, but reduces the Alternative Portfolio more since it has more IPP resources added. As seen in the table, when looking at a 15 per cent reduction in wind costs, the UEC of the portfolio with Site C drops by $5/MWh while the portfolio without Site C drops by $6/MWh which is due to different volumes of wind in each portfolio;**

- **The Alternative Portfolio includes the costs of the Site C sunk costs, termination and remediation. As a result, when fewer additional future resources are added to the portfolio, the UEC cost of that portfolio increases;**

- **As demand decreases, the gap between the Portfolio UEC decreases, but even in the low load scenarios, the portfolio with Site C has a lower UEC; and**

- **Note that Site C termination and remediation costs are included as costs in the "without Site C" portfolios rather than providing a credit to the "with Site C" portfolios. Site C sunk costs are in both portfolios.**

50.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 104

2.50.2 Parties are also requested to provide comment on the approach to the discount rate recommended by the CD Howe Institute.

RESPONSE:

The CD Howe Institute report is not relevant to the comparison of portfolio options undertaken as part of this inquiry. The CD Howe report focuses on project investment analysis, and comparing expected returns from a project to the required up-front capital investment. Projects with higher levels of uncertainty in realizing expected financial benefits (i.e., there is more risk) can be discounted at higher rates than projects with less uncertainty. The result is that riskier projects will need higher financial benefits to be as attractive as less risky projects.

In contrast, BC Hydro's analysis compares the costs of portfolios of multiple alternative resources and as such uses the discount rate to compare the annual costs of portfolios based on the expected "time preference" of ratepayers. If in portfolio PV cost analysis one were to apply a higher discount rate for portfolios of similar cost but higher risk, the distorted outcome would be that a riskier portfolio would result in lower PV costs and appear to be the preferred outcome.

BC Hydro notes that there is a difference in the analysis between the cost of financing and the discount rate, and that it did not use a risk free debt rate for its discount rate. Rather, the discount rate is based upon its Weighted Average Cost of Capital inclusive of debt costs and after tax return on equity (refer to Appendix K, page 3 of BC Hydro's August 30 Filing). BC Hydro also notes that it applied the same discount rate to all portfolios analyzed and did not use a different rate for portfolios that included Site C.

The CD Howe article is premised on the use of a discount rate adjustment to account for risks that impact the profitability or economic viability of a project. As described earlier, BC Hydro has explicitly considered many factors that could negatively impact Site C including capital cost overruns, lower demand, and lower market electricity prices. To address risks through a discount rate adjustment as well as through different sensitivities would be double counting the risks of the project. BC Hydro believes that the sensitivity approach provides a more transparent view of the risks to the projects and the impact of each as opposed to a subjective and blanket change in the discount rate.

BC Hydro's treatment of the cost of financing and discount rate are consistent with previous Commission findings on project evaluation methodology, contained in the Commission's decision concerning BC Hydro's 2006 Integrated Electricity Plan/Long-term Acquisition Plan (pages 183 to 208). Specifically:

- **The discount rate used for evaluations should be the same for BC Hydro projects and IPP projects. While it is possible to vary discount rates by adding a further project-related risk premium to reflect project-specific risks, the BCUC found that project-specific risks should be assessed through sensitivity analysis and contingencies as BC Hydro has done in its filing and IR responses; and**

- **For purposes of comparing BC Hydro and IPP projects, there should be recognition that BC Hydro will have a lower cost of capital given its access to the Province's high credit rating. For IPP projects, the relevant costs are the costs that reflect payments IPPs receive from BC Hydro and what ratepayers will pay.**

54.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 106

2.54.0 The Panel asks BC Hydro to confirm that it has used its mid forecast from the F17- F19 RRA in this RRIM analysis.

RESPONSE:

Confirmed.

60.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 - A-8

2.60.0 Given this, the Panel requests that BC Hydro explain why it is not renewing more IPP contracts.

RESPONSE:

BC Hydro renews IPP contracts where it is cost-effective to do so.

The planning assumptions we maintain from the 2013 Integrated Resource Plan (i.e., the renewal of 50 per cent and 75 per cent of the energy and capacity volumes for biomass and run-of-river resources, respectively) are not targets but provide a starting point for creating estimates within a financial framework. This then allows us to achieve the objective of being able to renew as much volume as possible, on a cost-effective basis, within an overall budget. BC Hydro expects that IPP renewals as a whole will likely have a lower cost relative to other potential clean or renewable greenfield supply options, other than Site C.

For biomass and run-of-river resources, BC Hydro's renewal assumptions are estimates of the likelihood of renewing 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 Electricity Purchase Agreement. Moreover, for biomass, our estimate for these renewals was further informed by our understanding of the reduced long-term certainty of available fibre supply.

As Electricity Purchase Agreements come up for renewal, each IPP project is individually assessed and the total volume of renewals is unknown until renewal agreements are reached with the counterparties. Our negotiations with individual IPPs are focused on achieving a cost effective renewal contract in the context of Recommended Action 4 from the 2013 Integrated Resource Plan, staying within the total cost forecast from the 10-Year Rates Plan, and our current Load Resource Balance.

64.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 - A-20

2.64.0 The Panel therefore seeks input from BC Hydro and other participants on the following questions:

- ***Clearly identify how much energy and associated capacity is included in the two options modelled (IRP DSM Plan and IRP DSM Plan Plus), with IRP DSM Plan Plus treated as incremental to the IRP DSM Plan.***
  - ***The annual energy/capacity savings and associated utility costs over the analysis period should be clearly stated.***
  - ***As the focus of this review is on costs to ratepayers (rather than broader BC benefits) please (i) estimate the utility (rather than total resource) cost, and (ii) assume that the incremental DSM options are delayed until is a need for new resources.***
  - ***The energy/capacity savings of DSM should be adjusted to reflect delivery (i.e., energy grossed up for distribution losses), and the cost should be adjusted for the DSM energy/capacity shape.***

Please do not include codes and standards/rate design in the incremental DSM portfolios.

RESPONSE:

This IR response has been organized according to the questions that were posed by the Commission.

- ***Clearly identify how much energy and associated capacity is included in the two options modelled (IRP DSM Plan and IRP DSM Plan Plus), with IRP DSM Plan Plus treated as incremental to the IRP DSM Plan.***
  - ***The annual energy/capacity savings and associated utility costs over the analysis period should be clearly stated.***

Appendix L of BC Hydro's August 30 Filing contains information on the energy and capacity savings and utility and total resource costs for BC Hydro's current DSM plan as well as two incremental options – the IRP DSM Plan and a high level sensitivity reflecting a larger level of DSM referred to as IRP Plan Plus. We have provided the information from Appendix L in tabular format as Attachment 1 to this response. The energy and capacity savings for the IRP DSM Plan and the

IRP Plan Plus are separate tranches and must be added to get the totals that are presented in Appendix L.

- ***As the focus of this review is on costs to ratepayers (rather than broader BC benefits) please (i) estimate the utility (rather than total resource) cost,***

BC Hydro has provided both the utility costs and total resource costs in the table attached to this response for the reasons set out below. However, BC Hydro believes that the Commission should be using total resource costs, not just utility costs, to compare DSM to other resource options.

Focusing on utility costs alone, rather than the total resource costs would represent a substantial departure to the Commission's approach to evaluating DSM options relative to supply-side options for utilities in B.C. The Commission acknowledged that the total resource cost test was the appropriate metric to compare DSM to supply-side resources in its 2009 Decision on BC Hydro's 2008 Long-Term Acquisition Plan Application:

> **The Commission Panel agrees with BC Hydro and finds that when comparing the [unit energy cost] UEC of a DSM program with the [unit energy cost] UEC of a supply-side option, the appropriate metric upon which to compare levelized $/MWh is the TRC. [p. 72]**

The total resource cost test reflects direct costs to ratepayers and includes both utility and customer costs, both of which would be borne by ratepayers. As a simple hypothetical example, consider the costs of an energy efficient light bulb, which costs $5 per bulb. A $1 incentive per bulb is offered by BC Hydro, which is the utility cost for this offer and would be reflected in BC Hydro's revenue requirement as a cost to ratepayers. However, what this analysis excludes is the customer cost ($4 in this example) that is also required for the investment in the energy efficient light bulb. The customer is a ratepayer and therefore the total resource cost presents the more complete assessment of the total ratepayer investment for the resource.

For this reason, the total resource cost is also the better metric to compare the costs of DSM to other resource options. Independent power producers or BC Hydro projects do not have distinctions between utility cost and total resource cost because, for these types of projects, the full cost of the project or contract is the utility cost. Using the total resource cost for resource evaluation decisions is consistent with how the majority of utilities and regulators evaluate DSM in North America and also consistent with the DSM Regulation.

The total resource cost test should not be confused with the societal cost test. The societal cost test would go beyond the total resource cost test to consider broader B.C. benefits and costs or externalities, which could include social costs

of carbon, economic impacts and public safety and health impacts. BC Hydro has not used the societal cost test in its resource acquisition analysis.

Total resource costs have been used in our PV analysis and sensitivity analysis to compare portfolios with and without Site C. Utility costs have been used in the rate impacts analysis.

- ***As the focus of this review is on costs to ratepayers (rather than broader BC benefits) please … (ii) assume that the incremental DSM options are delayed until is a need for new resources.***

The table in Attachment 1 to this response presents the savings from the incremental DSM options over Year 1, Year 2, Year 3 and so on. This is because incremental DSM options are delayed in the analysis until there is a need for new resources, which will depend on the specific load-resource balance assumptions in the portfolio being examined.

- ***The energy/capacity savings of DSM should be adjusted to reflect delivery (i.e., energy grossed up for distribution losses), and the cost should be adjusted for the DSM energy/capacity shape.***

The information presented in Appendix L and Attachment 1 to this response reflects energy savings grossed up to the system level to reflect losses and the cost reflects adjustments for the value of capacity.

- ***Please do not include codes and standards/rate design in the incremental DSM portfolios.***

The incremental savings represent only program energy and capacity savings and not additional savings from codes and standards and conservation rates.

RRA DSM	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041	F2042	F2043	F2044	F2045	F2046
Energy Savings (GWh/yr)	2114	2593	3231	3781	4258	4666	5016	5293	5666	5960	6159	6375	6602	6813	6927	6840	6813	6641	6574	6574	6574	6574	6574	6574	6574	6574	6574	6574	6574
Capacity Savings (MW)	396	476	603	719	793	852	899	934	982	1020	1045	1071	1097	1120	1131	1121	1127	1110	1103	1103	1103	1103	1103	1103	1103	1103	1103	1103	1103
Total Resource Cost ($ Million) [1]	83	102	123	142	161	177	192	206	219	231	244	254	265	246	231	211	200	188	176	166	158	150	144	138	134	128	124	120	117
Utility Cost ($ Million) [2]	146	85	82	80	80	78	77	77	76	76	76	76	75	73	72	73	72	73	71	70	69	67	66	65	63	62	61	60	59
IRP DSM Incremental to RRA DSM	Yr1	Yr2	Yr3	Yr4	Yr5	Yr6	Yr7	Yr8	Yr9	Yr10	Yr11	Yr12	Yr13	Yr14	Yr15	Yr16	Yr17	Yr18	Yr19	Yr20	Yr21	Yr22	Yr23	Yr24	Yr25	Yr26	Yr27	Yr28	Yr29
Energy Savings (GWh/yr)	137	260	424	715	1023	1293	1563	1848	2054	2195	2311	2429	2544	2690	2789	2921	2936	3158	3245	3189	3243	3328	3366	3359	3334	3368	3446	3446	3446
Capacity Savings (MW)	28	46	71	112	152	187	221	257	281	297	309	318	325	333	335	341	337	363	376	374	389	409	422	430	436	447	464	464	464
Total Resource Cost ($ Million) [1]	7	22	37	51	63	77	92	106	115	125	135	143	151	159	156	157	145	135	126	120	112	103	94	90	86	81	78	75	74
Utility Cost ($ Million) [2]	6	77	91	104	106	108	114	123	122	97	87	83	82	84	73	58	49	59	59	62	75	77	78	79	81	82	83	81	80
IRP DSM PLUS Incremental to IRP DSM	Yr1	Yr2	Yr3	Yr4	Yr5	Yr6	Yr7	Yr8	Yr9	Yr10	Yr11	Yr12	Yr13	Yr14	Yr15	Yr16	Yr17	Yr18	Yr19	Yr20	Yr21	Yr22	Yr23	Yr24	Yr25	Yr26	Yr27	Yr28	Yr29
Energy Savings (GWh/yr)	502	638	816	1005	1186	1341	1484	1616	1750	1850	1921	1998	2078	2163	2213	2214	2211	2214	2211	2191	2200	2218	2222	2215	2204	2208	2223	2223	2223
Capacity Savings (MW)	94	115	149	183	209	229	247	263	279	291	299	307	314	321	324	323	323	325	326	326	329	334	337	338	340	342	346	346	346
Total Resource Cost ($ Million) [1]	21	43	55	67	78	88	98	108	116	123	131	138	144	141	134	128	120	112	105	99	93	88	83	79	76	73	70	68	66
Utility Cost ($ Million) [2]	53	56	60	64	64	65	66	69	69	60	57	55	54	54	51	45	42	46	45	46	50	50	50	50	50	50	50	49	48

1. Net of regional transmission and distribution benefits, customers non energy benefits, gas benefits. Costs shown are costs as modeled in portfolio analysis reflecting 15-year amortization.
2. Gross utility costs. Costs shown are costs "as spent".

65.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 - A-23

2.65.0 The Panel invites BC Hydro to respond to the submission of Kleana Power.

The Panel invites parties to provide submissions on specific project data (including capital and operating costs, capacity factor and economic life) on potential Run-of- river projects.

RESPONSE:

BC Hydro provides the following background of our experience with Kleana and a unit energy cost analysis to reaffirm our conclusions that due to development risks and cost uncertainties the Kleana project is not economic when compared to other lower cost clean alternatives with or without Site C.

<u>Background</u>

On May 6, 2010, BC Hydro advised Kleana that BC Hydro had completed its evaluation of their proposal submitted under the 2008 Clean Power Call Request for Proposals, and that the proposal had not been successful and was no longer under consideration for an award of an electricity purchase agreement. The primary rationale was that the Project presented an unacceptably high level of development risk.

Subsequently Kleana brought forward a number of judicial reviews. In the appeal of the second judicial review application brought by Kleana in respect of its proposal, the BC Court of Appeal described Kleana's position as follows:

> **In effect, they took the position that…BC Hydro was to negotiate a contract for the purchase of electricity at a price that would burden ratepayers with the cost of purchasing hydro-electric power from a project the development of which, at least in 2012, was not viable at what was then a reasonable commercial price.**[1]

In dismissing Kleana's appeal, the BC Court of Appeal also rejected the premise that BC Hydro should be required to enter into agreements to purchase energy based on set prices free of Commission approval. Kleana's application for leave to appeal to the Supreme Court of Canada was dismissed in 2016.[2]

[1] ***Da'naxda'xw/Awaetlala First Nation v. British Columbia (Energy, Mines and Natural Gas)*, 2016 BCCA 163, paragraph 43.**

[2] ***Da'naxda'xw/Awaetlala First Nation v. British Columbia (Energy, Mines and Natural Gas),* leave to appeal to SCC denied No. 37074 (November 10, 2016).**

Unit Energy Cost analysis

The Kleana submission (F53-1) provides a proposal for a large run of river project with an installed capacity of 565 MW and about 2,450 GWh/year of average energy with over 40 per cent of its deliveries estimated to be in the freshet period.

As described in Appendix L, section 2.1, BC Hydro prepares our inventory of resource options with advice from independent advisors and in consultation with industry experts and others with technical expertise. While we will consider specific projects in developing our resource options inventory, we are careful about doing so given the expected bias for project proponents to provide artificially low cost information to influence our planning analysis in situations such as this – where there is no formal requirement for proponents to commit to such prices – resulting in little risk to the seller.

However, using information provided in Kleana Power's submission (F53-1) and in its submission in the 2008 Clean Power Call would produce an adjusted unit energy cost of approximately $112/MWh ($2018). BC Hydro found that including Kleana at the proponent submitted costs in our Block UEC analysis results in a levelized unit energy cost of approximately $154/MWh. This is not materially different from the $153/MWh alternative block cost using pumped storage and wind described in section 5.6.1 of our August 30 Filing. As a result, the inclusion of Kleana would not alter BC Hydro's conclusions reached in its August 30 Filing.

70.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 - A-31

2.70.0 The Panel requests that BC Hydro provide an analysis of how much, if any, natural gas fired generation can be relied upon for backup capacity given:

a) Section 6 and the 93 percent clean objective in the CEA
b) the Terms of Reference for this report, under there should be no increase in GHG intensity.

BC Hydro is requested to provide the process it applies to evaluate whether electricity imports are clean. What proportion of purchases in the past three years have been clean?

RESPONSE:

<u>Available Room for Natural Gas Generation</u>

BC Hydro interprets the Order in Council No. 244 Terms of Reference wording "maintenance or reduction of 2016/17 greenhouse gas emission levels" to require that the volume of GHGs emitted from BC Hydro's electricity generation be at or below 2016/17 levels going forward. The wording clearly states greenhouse gas <u>emission</u> levels and does not reference <u>intensity</u> levels. Our interpretation is consistent with the *Clean Energy Act* British Columbia Energy Objective "to reduce BC greenhouse gas emissions". BC Hydro's assessment is that we have no room for the addition of any new gas fired generation and this is the basis of the portfolios we have created. However, BC Hydro has assessed the available amount of natural gas fired generation if the above restriction did not apply, and only the restrictions identified by the Commission in items a) or b) apply. See below for this analysis.

a) Section 6 and the 93 percent clean objective in the CEA

BC Hydro meets the identified energy objective by ensuring that the average water output of heritage hydroelectric facilities combined with the firm capability of clean or renewable IPP resources would serve at least 93 per cent of the load net of DSM. The use of average water output for heritage resources and firm energy for IPP resources is consistent with the energy reliance from the resources in planning for energy self-sufficiency as required under the Clean Energy Act.

The amount of new natural gas capacity that can be developed while meeting the 93 per cent clean objective can be calculated as follows:

[Firm energy of existing gas generation + firm energy of new gas generation] ≤ 0.07 x Total Firm Energy

The expected load forecast is a suitable approximation for what the total firm energy of the BC Hydro system would be given the self-sufficiency requirements of the Clean Energy Act which requires the firm energy of all resources to be equal or higher than BC Hydro's expected load forecast.

Hence, the equation above can be expressed as

[Firm energy of existing non-clean generation + firm energy of new gas generation] ≤ 0.07 x Expected load forecast

BC Hydro owns or has electricity purchase agreements with a few non-clean generating resources including Prince Rupert generating station, Island Generation facility, McMahon co-generation facility, and Fort Nelson generating station. The total firm energy contribution from these facilities is approximately 3,500 GWh.

New gas generation relied upon for dependable capacity is expected to operate around 18 per cent of the time. This means that a 100 MW gas turbine would generate 150 GWh/year.

Hence, the capacity of new gas generation that can be built can be calculated as:

Capacity of new gas generation ≤ (0.07 x Expected load forecast - 3500)/(150/100)

The expected amount of new natural gas fired generation under a mid-load forecast with planned DSM is shown in the figure at the end of this IR response.

b) ***The Order in Council is interpreted as referring to the GHG intensity of electricity***

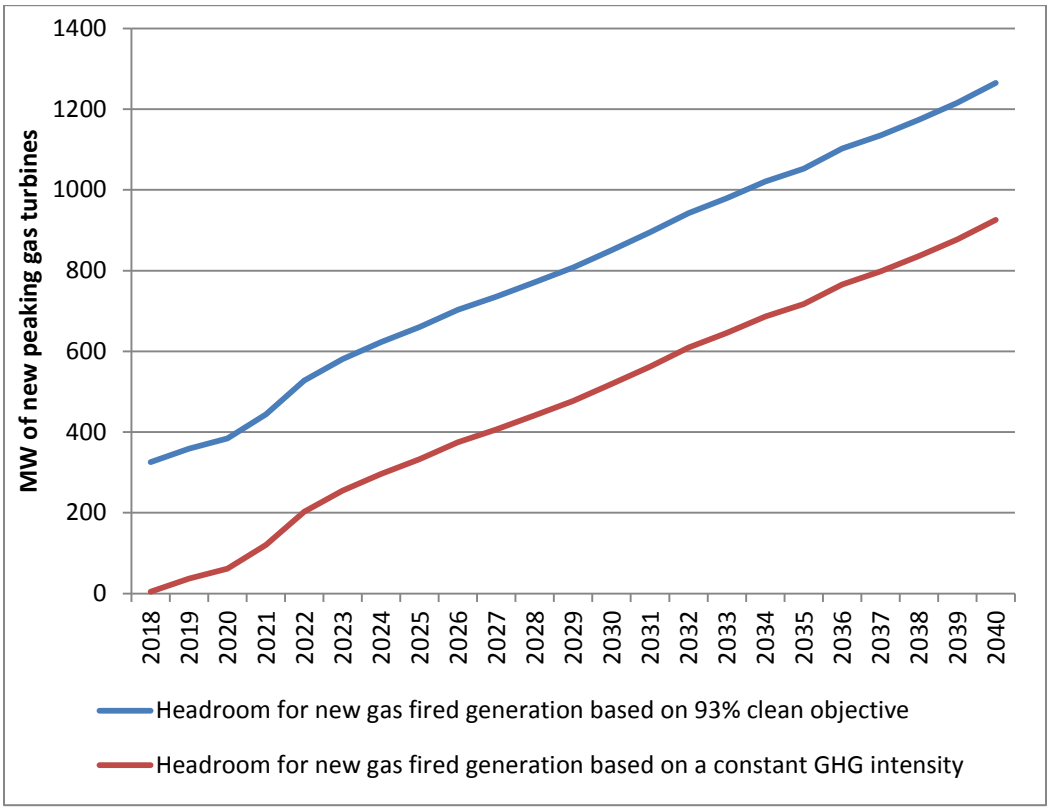
The emission intensity of BC Hydro system electricity has not yet been calculated for the 2016/17 period, however the emission intensity of the BC Hydro system can be estimated at 34.3 tonnes per GWh in for 2013-2015.[1] This emission factor is calculated by considering the emissions related to BC Hydro owned or contracted generation, market

[1] **Source: https://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/acs-power.htm. CARB publishes ACS Emission Factors based on a two-year lag. Data Year 2017 – ACS Emissions Factors are based on generation, import and export activity that occurred in 2015.The average of the values shown for data years 2015 to 2017 is equal to 34.3 tonnes per GWh.**

electricity imports, and exports of renewable power but does not include any GHG benefit associated with displaced GHG's energy exported higher GHG intensity regions. Assuming 2013 to 2015 is a reasonable estimate for 2016/17, for the intensity to stay the same going forward the average intensity of new generation needs to be less than or equal to 34.3 tonnes/GWh.

Simple Cycle Gas Turbines (SCGTs) are typically built for dependable capacity (for use as peakers). The emission intensity of generation from a SCGT varies with the make and model and is assumed to be 500 tonnes/GWh for the purpose of this calculation. This value is consistent with the SCGTs modeled in BC Hydro's resource options database.

As described previously, gas generation relied upon for dependable capacity is expected to operate around 18 per cent of the time. This means that a 100 MW gas turbine would generate 150 GWh/year which in turn translates to 75,000 tonnes of GHG emissions per year. The figure at the end of this IR response shows the capacity of SCGTs that can be built while maintaining the same GHG intensity under an expected mid load forecast with planned DSM.



<u>Assessment of Whether Electricity Imports are Clean</u>

Electricity imports are reported pursuant to the BC *Greenhouse Gas Emission Reporting Regulation* (the "*Regulation*"). Powerex, as an "electricity import operation" as defined under the *Regulation*, reports on an annual basis the emissions that are associated with the production of electricity that is imported into British Columbia and delivered to BC Hydro load using the standards defined in the *Regulation*.

Imported electricity is divided into three categories: electricity from (1) specified sources, (2) unspecified sources and (3) Canadian Entitlement Power.

A specified source is a source of imported electricity that can be identified as being generated from a specific facility. Emissions from specified sources are assigned the emission intensity of that specific facility. An unspecified source is a source of imported electricity, other than the Canadian Entitlement Power, that is not from a specified source. Emissions from unspecified sources are assigned the emission intensity from the jurisdiction or State that is listed as the source in the NERC e-Tag. The Canadian Entitlement is not assigned emissions.

Defining "clean" as Imported Electricity for which zero or *de minimus* tonnes of CO2 (less than 40 tonnes/ GWh) are associated, imports from clean resources (including the Canadian Entitlement Power) for the three most recent reporting years (2014 to 2016 inclusive), was 65.9 per cent.

78.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 92

2.78.0 The Panel finds that the usefulness of the UEC is limited to a comparison methodology because it doesn't appear to take into account when the energy source comes on line BC Hydro is invited to explain how the UEC accounts for this timing issues.

RESPONSE:

BC Hydro agrees with the Panel that the usefulness of the simplified "Block UEC Analysis" described in section 5.6 is limited as a comparison tool. For further explanation as to why this is the case please refer to section 5.5 of our August 30 Filing. For additional discussion and options to modify the UEC to take into account some of the factors in portfolio analysis, refer to BC Hydro's response to BCUC IR 2.45.0. We continue to believe that portfolio analysis is the most comprehensive analysis and should be used for comparing resource options.

82.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 39

2.82.0 The Panel notes that many of BC Hydro's existing facilities were built with options for expansion. For example, Mica and Revelstoke were initially built with four generators each. Many years later Revelstoke had one generator added and Mica has recently had two generators added. BC Hydro is requested to comment on the costs and benefits installing fewer generators initially at Site C, followed by more generators at a later date to perhaps better match energy and capacity needs.

RESPONSE:

If a decision was made at this point in the project to leave one or more unit bays empty and defer installation of the generating equipment until a later stage:

- **costs to construct the empty unit bay(s) would still be incurred, and would amount to a significant portion (on the order of 50%) of the costs of completing the unit bay(s);**
- **while some initial incremental savings in equipment capital cost may be realized, the maximum potential of these savings would not be expected to be fully realized;**
- **any incremental savings would be offset by other costs introduced by leaving an empty unit bay(s) (e.g. additional design and construction modifications that would be necessary to strengthen and stabilize the powerhouse); and**
- **the value of the operational flexibility and outage management benefits associated with the generating unit(s) to be deferred, would not be realized.**

Overall, potential cost savings associated with deferring installation of one or more generating unit(s) could be expected to be minimal at best, and further, would result in BC Hydro completely foregoing the operational flexibility and outage management benefits associated with the generating unit(s) that would otherwise have been installed.

BC Hydro provides the following information in support of the summary statements above:

- **During the initial construction of the Mica and Revelstoke plants, two additional bays were left empty at both projects to provide the option**

to add units to meet future capacity and energy shaping requirements within the province. Revelstoke, the downstream plant, was originally constructed with a higher hydraulic capability than the upstream Mica plant. Throughout the process of adding units to the two plants, the hydraulic capability at Revelstoke (the downstream plant) remained higher than the hydraulic capability of Mica (the upstream plant), to reduce the frequency of times when the downstream plant becomes a bottleneck and impacts the flexibility of generation upstream. If a downstream plant such as Site C is built with less hydraulic capability than the upstream plants (in this case, GM Shrum and Peace Canyon), then not only will the downstream plant be restricted, but that restriction will cascade to upstream plants. As a result, deferral of any more than one Site C generating unit would result in more frequent negative operational impacts at upstream facilities.

- **Geotechnical and civil/structural construction costs would be expected to remain largely unchanged (i.e. the cost to construct the unit bay). These costs would be expected to represent a large portion (on the order of 50 per cent) of the total cost of installing a generating unit bay at initial construction (complete with the generating unit itself).**

- **The structural design of the powerhouse is optimized such that, without the weight and structural contribution of the second stage concrete within each unit bay, the current design would have to be modified to assure strength and stability and address powerhouse layout and construction sequencing issues that would arise. The required modifications would have additional engineering and construction costs associated with them, which could offset any initial capital cost savings that might be realized by not placing second stage concrete during the initial powerhouse construction.**

- **The cost of installing a generating unit in an empty bay at a later date would be higher when considering factors such as additional development costs, regulatory costs, procurement costs, re-mobilization costs, and inflation. A complete Project Team would need to be re-assembled and re-acquainted with the Project spending up to five years before construction.**

- **An incremental savings in equipment capital and maintenance costs could be realized, associated with foregoing the purchase of the generator, turbine, and some associated auxiliary equipment (Note: generator step-up transformers are shared between two generating units as a result of design optimization, and as a result, transformer savings could not be realized unless two generating units were not installed at initial construction). That said, there is no specific provision in the Site C Turbine-Generator Contract to purchase less than 6 units, and if less than six units were contemplated a Change Order would need to be negotiated with the supplier. Since the**

design of the turbine-generator is well advanced and either manufacture of certain components or in some cases delivery to Site of components for all six units has occurred, BC Hydro would not recover full savings if one unit was purchased later than the current schedule. The turbine-generator contractor would likely ask for increased costs related to restocking, storage, remobilization, carrying costs, and increased installation costs.

- **There would be no benefits to system operations from deferring generating units. The provision of 6 units, with a hydraulic capacity that will usually exceed the combination of Peace Canyon releases plus local inflow, will enhance operational flexibility as well as BC Hydro's ability to manage planned and unplanned outages. This flexibility is considered to have the following benefits;**

    - **During Site C unit forced or planned outage periods, upstream storage releases will be less likely to be hydraulically constrained. As well, unit transformer outages that have the potential to force two units out of service, will be less impactful to hydraulic capacity. Under optimal system operation, hydraulic constraints at Site C resulting from installing fewer units would likely result in an incremental increase in spill frequency and volume at both upstream plants and at Site C.**

    - **During periods of high system energy requirements, the high release capability of the plant will provide flexibility to draft the Site C reservoir within the operating range. Through this operation, the plant can be utilized to further enhance daily and weekly load and market serving requirements.**

    - **Additional flexible capacity held in reserve at Site C will have additional market value, particularly when accessing the emerging California Energy Imbalance Markets.**

83.0 Reference: BCUC Inquiry Respecting Site C Preliminary Report dated September 20, 2017 – Page 36 and 37

2.83.0 BC Hydro has estimated $1.8 billion in interest charges if the project is suspended, started again in 2024 and completed in 2031. BC Hydro is requested to provide its assumptions and calculations leading to the $1.8 billion."

RESPONSE:

As described on page 90 of BC Hydro's Submission, BC Hydro has estimated that the costs to be recovered from ratepayers under the suspension scenario will total $12.9 billion. Of that total amount, approximately $1.73 billion relates to additional interest costs from F2018 to F2031. Because of rounding this was shown as $1.8 billion to allow the individual components, when rounded to one decimal place, to sum to the total calculated $12.9 billion amount.

Please refer to the attached working Excel file for a calculation of the $1.73 billion amount of total forecast interest, which is shown on Line 14.0.

BC Hydro has forecast that the balance in the Site C Regulatory Account at December 31, 2017 (the estimated time a decision would be made to suspend the Site C project) will be $0.465 billion.

As described on pages 88 and 89 of BC Hydro's Submission, in addition to the Pre-FID costs already in the Site C Regulatory Account at December 31, 2017, BC Hydro has forecast that the following additional costs will be transferred to the Site C Regulatory Account:

1. **$1.635 billion – Project Capital Costs Between FID and Suspension Date;**
2. **$0.891 billion – Suspension-related Costs; and**
3. **$0.257 billion – Maintenance Costs.**

Including the forecast balance of $0.465 billion, this results in total direct costs, before interest, of $3.247 billion in the Site C Regulatory Account.

BC Hydro has assumed that costs added to the Site C Regulatory Account will incur interest at BC Hydro's forecast weighted average cost of debt, and will incur interest until the end of fiscal 2031, which is the estimated completion date of the suspended and later resumed Site C project.

For the total $2.1 billion related to Pre-FID costs already in the Site C Regulatory Account ($0.465 billion) at December 31, 2017 and Project Capital Costs Between FID and Suspension Date ($1.635 billion), forecast interest is applied to the balance of the account each year, and is shown on Line 3.0 of the attached working Excel file.

For Suspension costs ($0.891 billion), the full liability is to be recognized at December 31, 2017, and BC Hydro has assumed that this amount will be transferred into the Site C Regulatory Account at that same time. BC Hydro has assumed that this component of the Site C Regulatory account will initially not attract interest, as there will have been been no cash outlay (i.e., BC Hydro has not incurred any debt). BC Hydro has assumed interest should be included only once the expenditure is made. The calculation of the interest related to the Suspension costs is shown separately in Lines 16.0 to 24.0 of the attached working Excel file.

For Maintenance costs ($0.257 billion), BC Hydro has assumed interest should be included only once the expenditure is made (i.e., when BC Hydro will have incurred debt). The calculation of the interest related to the Maintenance costs is shown separately on Line 7.0 of the attached working Excel file.

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