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Utilities Commission

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March 19, 2018

Sent via eFile

BC HYDRO WANETA 2017 TRANSACTION
EXHIBIT A-19

Mr. David Austin
CLARK WILSON LLP
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900-885 West Georgia Street
Vancouver, BC V6C 3H1
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Re: British Columbia Hydro and Power Authority – Waneta 2017 Transaction Application – Project No. 1598933 – Commission Information Request on Intervener Evidence

Dear Mr. Austin:

Further to the March 12, 2018 filing of the Evidence on behalf of the Clean Energy Association of B.C. (Exhibit C6-6), enclosed please find British Columbia Utilities Commission Information Request No. 1 on Intervener Evidence.

In accordance with the regulatory timetable, please file your responses on or before Monday, March 26, 2018.

Sincerely,

Original signed by:

Patrick Wruck
Commission Secretary

/dg
Enclosure

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British Columbia Hydro and Power Authority
Waneta 2017 Transaction Application

INFORMATION REQUEST NO. 1 TO CLEAN ENERGY ASSOCIATION OF BC ON INTERVENER EVIDENCE

1.0 Reference: INTRODUCTION
Exhibit C6-6, p. 1; Exhibit B-18, BCUC IR 2.81.1 and 2.83.3; Exhibit B-1, Business Case, p. 19
Long-run marginal cost (LRMC)

Clean Energy Association of BC (CEABC) states:

> There have been some significant changes in the electricity industry that are not fully reflected in B.C. Hydro's ("*BCH*") calculation of the Long Run Marginal Cost ("*LRMC*") that is used in the business case for the proposed acquisition of the remaining two thirds interest in the Waneta Generating project ("*Waneta Business Case*").
>
> …
>
> In his capacity as the Executive Director of the Clean Energy Association of B.C. ("*CEABC*") and on behalf of the CEABC, Mr. Jae Mather provides details of some of these common financial assumptions and unreflected industry changes, primarily as noted in the Site C Final Report, but also as updated by a recent competitive bidding process for renewable generation in Alberta. The use of these updated assumptions and changes in the Waneta Business Case would lead to a more balanced comparison with the renewable generating alternatives.

In BCUC IR 2.81.1, the Commission asked the following question:

> In light of the steep declines in wind costs, as shown by the recent Alberta projects, please re-calculate the combined energy and capacity LRMC using $60/MWh ($F2018) for Energy Greenfield IPPs for F2034 and beyond, using the 6.4 per cent (real) financing cost assumption provided in BCUC 1.10.4.

In response to that BCUC IR 2.81.1, BCH provided the following response:

Marginal Resources	Period of Applicability	LRMC (2018 real dollars)					
		Clean + Gas (Requested)	Clean + Gas (6.4% Financing)	Clean + Gas (Business Case)	Clean Only (Requested)	Clean Only (6.4% Financing)	Clean Only (Business Case)
Energy: Greenfield IPPs	F2034 and beyond	$60/MWh	$105/MWh	$106/MWh	$60/MWh	$105/MWh	$106/MWh
Capacity Resources	F2029	$75/kW-year (Industrial Load Curtailment)	$75/kW-year (Industrial Load Curtailment)	$88/kW-year (SCGT)	$75/kW-year (Industrial Load Curtailment)	$75/kW-year (Industrial Load Curtailment)	$221/kW-year (pumped storage)
Capacity Resources	F2030 and beyond	$81/kW-year (SCGT)	$81/kW-year (SCGT)	$88/kW-year (SCGT)	$176/kW-year (pumped storage)	$207/kW-year (pumped storage)	$221/kW-year (pumped storage)
Combined Cost of Energy & Capacity	Effective for F2034 and beyond	$74/MWh	$119/MWh	$122/MWh	$91/MWh	$142/MWh	$145/MWh

In BCUC IR 2.81.2, BC Hydro stated:

> The requested range of LRMCs is lower than the sensitivity scenarios in Table 11 of the Waneta 2017 Business Case, but is within the sensitivity scenarios provided in BC Hydro's response to BCUC IR 2.83.3. The response to BCUC IR 2.83.3 includes the LRMC (Clean+Gas) less 40 per cent scenario, which has an effective LRMC of $73/MWh for fiscal 2034 and beyond.

The following is an excerpt from the table provided in response to BCUC IR 2.83.3:

Basis for Post-Lease Value	Value of Assets / Lease to BC Hydro					
	Un-risked Lease Period	Default Risk Adj.	Post-Lease Value	Extension Option	Total Value	Value net of purchase
LRMC (Clean+Gas) less 40% (BCUC IR 2.81.2)	792	19	663	(33)	1,441	238

In the Business Case, BC Hydro summarized the LRMC scenarios in Table 3:

Table 3 Marginal New Resources and Related Costs

Marginal Resources	Period of Applicability	LRMC (2018 real dollars)	
		Clean + Gas	Clean Only
Energy: Greenfield IPPs	F2034 and beyond	$106/MWh	$106/MWh
Capacity Resources	F2029 and beyond	$88/kW-yr (SCGT)	$221/kW-yr (pumped storage)
Combined Cost of Energy & Capacity	Effective for F2034 and beyond	$122/MWh	$145/MWh

1.1 The $60/MWh ($F2018) price for wind energy that Commission asked BC Hydro to use in BCUC IR 2.81.1 represents a 43 percent reduction from the $106/MWh ($F2018) used by BC Hydro in Table 3 of the Business Case. This lower price translated into an LRMC (Clean + Gas) of $74/MWh and an LRMC (Clean) of $91/MWh, representing reductions of 39 percent and 37 percent compared to the LRMC shown in Table 3. What is CEABC's view of the LRMCs BCH re-calculated for BCUC IR 2.81.1?

1.1.1 Please explain what further market changes, if any, CEABC views should be included in the calculation of the LRMC and how the resulting LRMC would differ from the LRMC in the BC Hydro response to BCUC IR 2.28.1. Please explain these differences and provide supporting data.

1.2 In the case that CEABC agrees the LRMCs recalculated for BCUC IR 2.81.1 reflect the changes in the electricity industry as well as the other adjustments noted in Exhibit C6-6, does CEABC agree with BC Hydro's recalculated value of the net purchase at $238 million, when taking into account default risk, extension option, and an LRMC set at 40 percent lower than the LRMC (Clean + Gas), which encompasses the wind energy price of $60/MWh? Please explain.

2.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 1 and 2

In BCUC IR 2.80.1, BCH states:

> Factors 1 and 2 are clear differences between B.C. and Alberta. […]
>
> 1. Location and Terrain – Location and terrain affect cost factors such as construction, interconnection, transportation, labour and accessibility, and hence have an impact on installed capital costs as well as the operations and maintenance costs. B.C.'s terrain is generally much more complex and wind sites much more remote in comparison to Alberta's rolling hills and ranch land. 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[2] for two wind projects, one built in Alberta, the other in B.C. The two projects, which were both commissioned in 2012, are roughly of the same size, and use 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. It is likely that most of this difference in cost is attributable to location and terrain. Keeping all other factors constant, this amounts to an almost $20/MWh difference in the wind price.
>
> 2. Wind service sector – Having an established wind service sector allows for lower operations and maintenance costs due to economies of scale. Southern Alberta has an established wind service sector with 1480 MW of installed capacity. Northeast B.C.'s installed wind capacity is 570 MW and has not seen the same economies of scale as Southern Alberta.

CEABC states that:

> **4.1 Location and terrain** – Using data for projects built in B.C. and Alberta in 2012 to conclude that the location and terrain in B.C. account for a 38% price differential is a sample set of n= 1 and thus not a terribly useful exercise. How Capital Power allocates costs as between its projects, particularly in the same year, is completely unknown.
>
> **4.2 Wind service sector** – The four large wind projects in northeast B.C. have already resulted in the establishment of a wind service sector in this portion of B.C.

2.1 Please provide, if available, a comparison of wind project costs in Alberta and BC, including an identification of the causes of any cost differentials, as well as any studies or research papers CEABC is aware of that have investigated the wind cost differential by geographic regions in Canada.

2.2 In CEABC's view, what types of services are comprised in a wind service sector?

2.3 Please provide supporting data to the statement that a wind service sector is established in northeast BC (e.g., number of firms/employees operating, part-time versus full-time employment, annual dollar amount of services generated in this industry, and any other relevant socio-economic data).

2.3.1 How does the wind industry compare to that of Alberta using the same metrics?

2.4 In CEABC's view, has the BC industry already achieved the lower operations and maintenance costs due to economies of scale referred to by BC Hydro? Please explain why or why not.

3.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 3 to 7

BCH states that "[t]he other factors may or may not be applicable to B.C. or repeatable in another acquisition processes."

CEABC provides the following comments regarding Factors 3 to 7:

4.3 Size of developer – CEABC's members include some of the same large national or global developers that participated in the Alberta bidding process and/or were awarded contracts.

4.4 Brownfield vs greenfield development – There are large wind sites in B.C. that are considered to be brownfield sites. However, with advances in technology this does not necessarily mean the brownfield sites have a cost advantage.

4.5 Financing assumptions – Large national or global developers have already participated in the development of large wind projects in B.C. Their financial resources are not exclusive to Alberta.

4.6 Terminal Value – BCH's decision to not assign a terminal value of at least 30% at end of life is not realistic. The reality is that at the end of a 25 - year contract there is considerable terminal value in a large wind site including infrastructure, local relationships and knowledge of wind conditions.

4.7 Bidding Strategy – Developers are not in the business of developing projects to achieve sub-optimal returns. For example, there is no evidence that building one large wind project will necessarily result in the development of another immediately adjacent large project. It depends on the circumstances including technological advances.

3.1 Please elaborate on CEABC's comment 4.3. Can CEABC quantify the cost differential achievable by a medium size wind developer versus a large national or global developer? Please provide your assumptions and calculations.

3.2 Before the advances in technology referenced in CEABC's comment 4.4, what was the cost differential due to brownfield versus greenfield sites. Please provide the supporting data/sources.

3.3 Please clarify the kind of technological advances that have, in CEABC's view, eliminated the cost advantage of brownfield sites.

3.3.1 Please provide supporting data/sources showing that the cost differential was indeed eliminated by these technological advances.

3.4 Please clarify the link between CEABC's comment 4.5 and BC Hydro's statement on Factor 5, taking into account EDC Associates' WACC analysis attached in Footnote 3 (pages 3–4) of BC Hydro's response to BCUC IR 2.80.1.

3.5 For CEABC's comment 4.6, please provide supporting data/sources for the terminal value of at least 30 percent at end of life.

3.5.1 Please also provide CEABC's estimate of the cost differential in MWh resulting from not assigning a terminal value to the BC wind projects.

3.6 For CEABC's comment 4.7, please clarify whether CEABC's premise for sub-optimal returns is an individual project or a portfolio of projects (or multi-phase)?

3.6.1 Please confirm, otherwise explain, that in CEABC's view it could be possible for a developer to achieve sub-optimal returns on an individual project with the hope of achieving optimal return for the portfolio of projects.

3.7 Please clarify why the Commission should attribute more weight to CEABC's comment 4.7 on potential bidding strategy than to BC Hydro's comment on potential bidding strategy.