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Date: October 11, 2017

Subject: Submission - Problems with BC Hydro Response F1.8

McCullough Research

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Principal

Date: October 10, 2017

To: British Columbia Utilities Commission

From: Robert McCullough

Subject: Problems with BC Hydro Response F1.8

Request No. 2.61.0

British Columbia Hydro continues to characterize Site C as if it had significant storage and operational flexibility:

> Site C will add significant capacity and flexibility to the BC Hydro system, helping BC Hydro reliably meet BC Hydro's peak and annual load requirements. It will also increase the surplus capacity and flexibility during hours of the year when loads are lower than peak loads. As a result, all else being equal, Site C can be expected to increase Powerex's ability to generate value for BC Hydro ratepayers from the residual capacity and flexibility of the BC Hydro system. More specifically, the addition of Site C can be expected to increase the ability of Powerex to sell surplus energy in the higher-priced hours of the year, while also increasing the ability of Powerex to purchase energy in the lower-priced hours of the year (enabling additional sales in higher-priced hours). In addition to supporting increased energy sales and purchases, the increase in capacity and flexibility provided by Site C throughout the year can be expected to increase the ability of Powerex to sell capacity and/or flexibility products, whereby Powerex receives an explicit capacity and/or flexibility payment.[1]

As BC Hydro's own submission F1.1, Appendix F explains, this is not the case:

> The Project reservoir, with a normal operating range of 1.8 m and an active storage volume of 0.4 per cent of the active storage volume of Williston Reservoir, does not have sufficient storage volumes to provide seasonal

[1] British Columbia Utilities Commission Information Request No. 2.61.0 Dated: September 20, 2017 British Columbia Hydro & Power Authority Response issued October 3, 2017, page 1.

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> shaping of generation. The upstream regulation at Williston Reservoir allows the Project to generate electricity to match the timing of BC Hydro customer demand without the need to establish another large multi-year storage reservoir similar to Williston Reservoir. As a result, the Project is able to produce approximately 35 per cent of the energy produced by the G.M. Shrum generating station with 5 per cent of the reservoir area.[2]

Site C has limited shaping ability – primarily restricted by the very low 1.8 meter reservoir operating range.

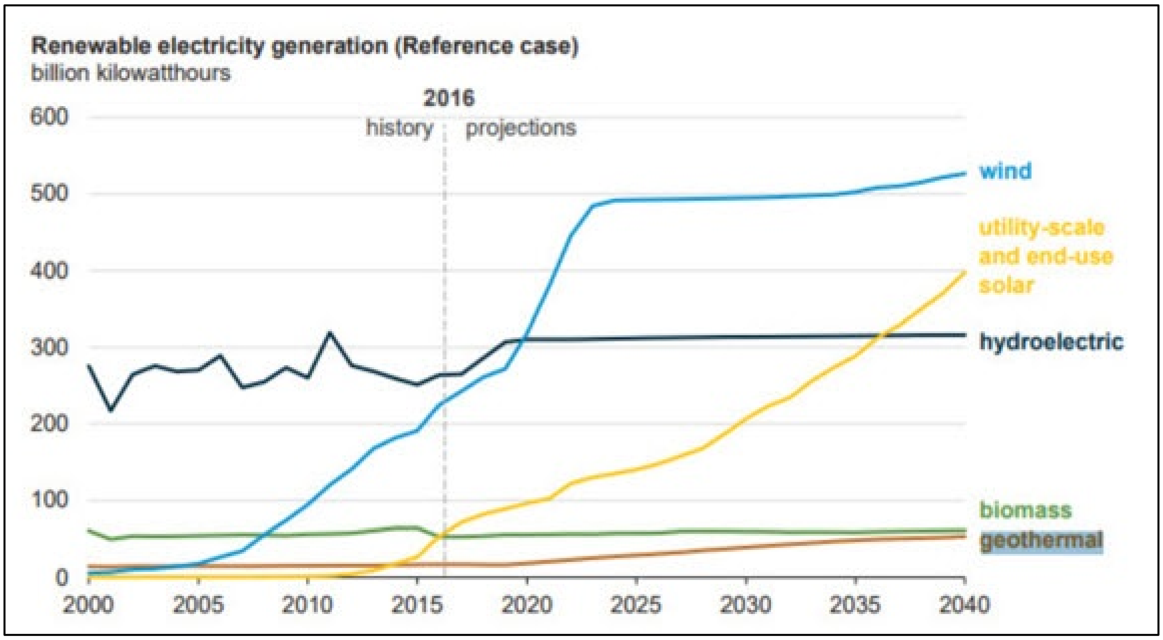
Request No. 2.61.0:

British Columbia Hydro's low expectations for the U.S. geothermal industry are not shared in the United States. British Columbia Hydro states:

> Even in the U.S. – with an established geothermal industry and with many geothermal reservoirs fully explored and de-risked – only 77 MW of geothermal at two expansion sites were brought online in 2015. This is despite a geothermal project pipeline in the U.S. of 6.4 GW by 2015. This suggests that steady growth of successful geothermal projects must be supported by broad-based efforts to advance a wide portfolio of potential geothermal projects, most of which are sure to be cancelled or postponed.[3]

The highly respected U.S. Energy Information Agency has released their annual energy forecasts for the U.S. this year. They use actual geothermal supply curves and apply them regionally across the U.S. Their chart for future geothermal shows a very healthy growth rate:

[2] BC Hydro Submission to the British Columbia Utilities Commission Inquiry into the Site C Clean Energy Project, September 30, 2017, Appendix F, pages 2 and 3.
[3] British Columbia Utilities Commission Information Request No. 2.61.0 Dated: September 20, 2017 British Columbia Hydro & Power Authority Response issued October 3, 2017, page 3.



[4]

Request No. 2.22.1:

British Columbia Hydro's discourse on the recently filed request by the U.S. Department of Energy is inaccurate:

> Finally, it should be noted that there are existing efforts by the current U.S. federal government to maintain the viability of the existing coal and nuclear fleet. On September 29, 2017 the U.S. Department of Energy proposed a "Notice of Proposed Rulemaking" that, if adopted, would support base loaded "fuel secure" resources in organized markets. An ongoing debate is expected between state and federal governments on the future of coal and nuclear resources. Importantly, the NOPR applies to resources within organized markets, whereas most of the coal resources in the western U.S. that are currently slated to retire between 2020 and 2025 are outside of organized markets.[5]

The U.S. Department of Energy has asked the Federal Energy Regulatory Commission for an order directing the nation's Independent System Operators to provide traditional cost based regulatory treatment for plants with the ability to operate ninety days without off-

[4] Annual Energy Outlook 2017, Energy Information Administration, January 5, 2017, page 78.
[5] British Columbia Utilities Commission Information Request No. 2.22.1 Dated: September 20, 2017 British Columbia Hydro & Power Authority PUBLIC Response issued October 4, 2017, page 5.

site fuel deliveries.[6] This proposed order is not applicable to the west coast of the U.S. and Canada for a number of reasons:

1. The only independent system operator on the west coast is the California ISO.
2. The California ISO has responsibility for most but not all of California.
3. The California ISO's footprint does not include any plants that would be covered under this order.

Interestingly, where this order does apply, its impact will be to lower off-peak energy prices and to provide an incentive to operate older, uncompetitive plants that would otherwise be closed by market forces. If it did apply to the west coast, it would reduce the export revenues, not increase them.

Request No. 2.22.1:

The submission argues that renewable resource markets are unlikely to extend to British Columbia for economic reasons:

> Renewable energy sales opportunities continue to be limited from B.C., and are especially limited in the context of investing capital in new B.C. renewable resources for export, as:
>
> • RPS programs set a minimum percentage of load that each load-serving entity in the applicable region must serve with energy procured from renewable resources that meet certain qualification requirements defined by each particular state.
>
> • The only B.C. resources that qualify for California's RPS, the largest market for renewable resources, are B.C. wind resources (despite considerable efforts to gain eligibility as renewable resources for other types of B.C. resources).
>
> • The cost of building new wind resources in B.C., and delivering those resources to California (or other western U.S. markets to meet applicable state RPS targets), generally exceeds the cost of building local renewable resources in the destination state – especially with a 30 per cent investment tax credit for U.S. renewables."[7]

[6] Grid Reliability and Resilience Pricing Docket No. RM18-1-000, FERC, October 2, 2017.
[7] British Columbia Utilities Commission Information Request No. 2.22.1 Dated: September 20, 2017 British Columbia Hydro & Power Authority PUBLIC Response issued October 4, 2017, page 6.

This is an interesting argument, but one without significant merit. Other locations in Canada don't seem to be constrained in renewable investment by economic factors. Both Quebec and Ontario have extensive renewable portfolios. Many, if not most, non-utility developers are based in Canada ranging from aboriginal groups, municipalities, and local businesses.

Last week, two Canadian firms announced major wind farms within the Northwest Power Pool. The two new projects are equal to the entire wind sector in British Columbia.[8]

Request No. 2.22.1:

British Columbia Hydro's load forecast submissions appear to have little relevance to current market conditions. The Mid-Columbia energy hub is the oldest and largest in the world. The hub supports extensive financial markets including both derivatives and forward supplies at a number of major exchanges including the Inter-Continental Exchange (ICE) and the Chicago Mercantile Exchange (CME). Good forecasts do not actually forecast future prices at odds with published prices – simply because the actual market prices are the best evidence for future periods.

The BC Hydro submission states:

> Table 1 below shows BC Hydro's Mid C market price forecast for calendar year 2025 and 2034 in CAD and USD. Wheeling costs to and from Mid C are assumed to be constant at current levels of 6.28 CAD/MWh. Losses due to transmission to and from Mid C are 1.9 per cent of power transferred, resulting in in incremental costs for purchase and a loss of revenue for sales.

	Mid C 2016 USD/MWh			Mid C 2016 CAD/MWh			Losses (1.9%) 2016 CAD/MWh			Wheeling 2016 CAD/MWh	B.C. Buy 2017 CAD/MWh			B.C. Sell 2017 CAD/MWh		
Calendar Year	On Peak	Off Peak	Average	On Peak	Off Peak	Average	On Peak	Off Peak	Average	-	On Peak	Off Peak	Average	On Peak	Off Peak	Average
2025	36.46	35.76	36.16	45.70	44.82	45.32	0.87	0.85	0.86	6.28	53.58	52.68	53.20	39.09	38.22	38.72
2034	45.53	45.41	45.47	57.06	56.91	56.99	1.08	1.08	1.08	6.28	65.32	65.17	65.26	50.39	50.24	50.33

> Exchange rate assumption: Rates based on updates provided by the Treasury Board of the Province of B.C. May 30, 2017. 1USD = 1.2533CAD Inflation assumption: CPI from Statistics Canada - updated 2017-01-20. CPI increase in 2016 = 1.4 per cent.[9]

[8] Canadian Wind Development Dipping Toe Into Northwest, Clearing Up, September 29, 2017, page 10.
[9] British Columbia Utilities Commission Information Request No. 2.22.1 Dated: September 20, 2017. British Columbia Hydro & Power Authority PUBLIC Response issued October 4, 2017, page 8.

ICE provides detailed reports on forward prices at the Mid-Columbia Hub. The relevant reports are for forward contracts MDC (on-peak) and OMC (off-peak).[10] On-peak prices for 2025 averaged US$33.35/MWh. Off-peak prices for 2025 averaged US$26.89/MWh.

The forecast in the table above is off by 10% for on-peak and 30% for off-peak. This implies strongly that BC Hydro's entire Mid-Columbia forecast is in error.

Request No. 2.22.1

BC Hydro has postulated a high correlation between Sumas natural gas prices and the Mid-Columbia hub. This is an unsubstantiated assertion and one that is highly inaccurate. The Mid-Columbia hub has supplies from a variety of fuel sources ranging from hydro to coal and natural gas. The highest operating cost resources set prices when the specific resources are being dispatched. Combined cycle natural gas units have a role in the market, but prices are generally set by a variety of forces and by natural gas prices at a variety of locations.

British Columbia Hydro's submission states:

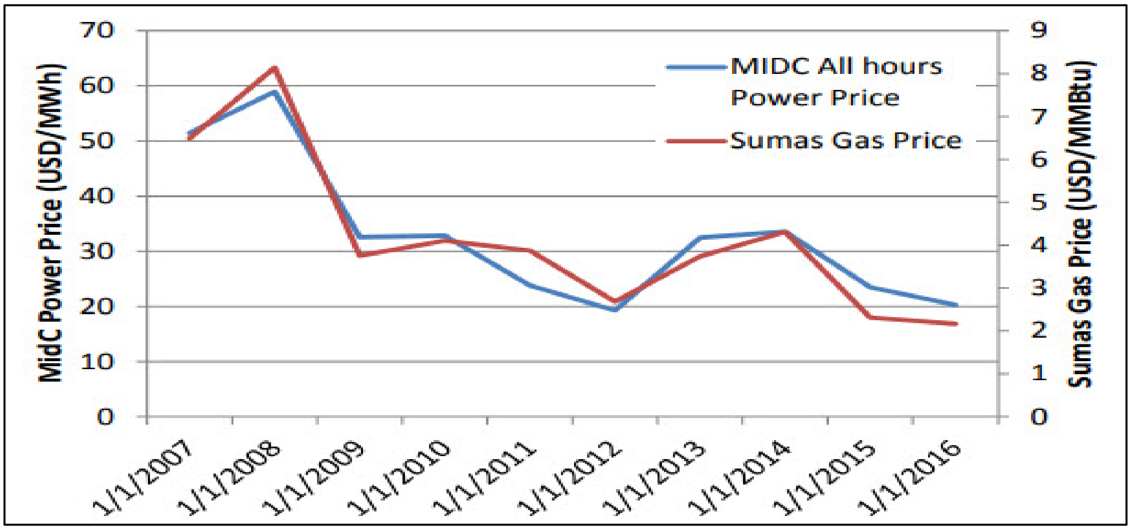
> Sumas gas from 2007 to 2016. It is clear from this chart that price movements in power have closely followed changes in natural gas prices. The second chart below removes the effect of the natural gas price on the power prices by showing the market Heat Rate at Mid C, which is simply the power price divided by the gas price. This generally stable Mid C heat rate illustrates that once the effects of declining gas prices is removed, average Mid C market prices have remained generally unchanged over the past seven years. It would be incorrect to conclude that average Mid C prices have fallen largely as a result of increased renewable resources.[11]

The statement that Mid-Columbia prices have remained unchanged over the past seven years is extraordinary, and contrary to the actual marketplace. Among other issues, the burgeoning renewables sector has created over-generation periods where the prices have actually gone negative for significant periods. The past year at Mid-Columbia had the lowest prices in history. Forward markets are indicating a continuing fall for the next two years.

The basis for British Columbia Hydro's claim appears to be a simple annual chart for the past decade using nominal prices. Introductory forecasting classes usually advise against such an analysis since the annual average tends to disguise actual market dynamics. In

[10] https://www.theice.com/marketdata/reports/142 accessed on October 9, 2017.
[11] British Columbia Utilities Commission Information Request No. 2.22.1 Dated: September 20, 2017 British Columbia Hydro & Power Authority PUBLIC Response issued October 4, 2017 Page 13

addition, over a significant period, inflation tends to affect all prices – thus confusing market dynamics with overall price changes.

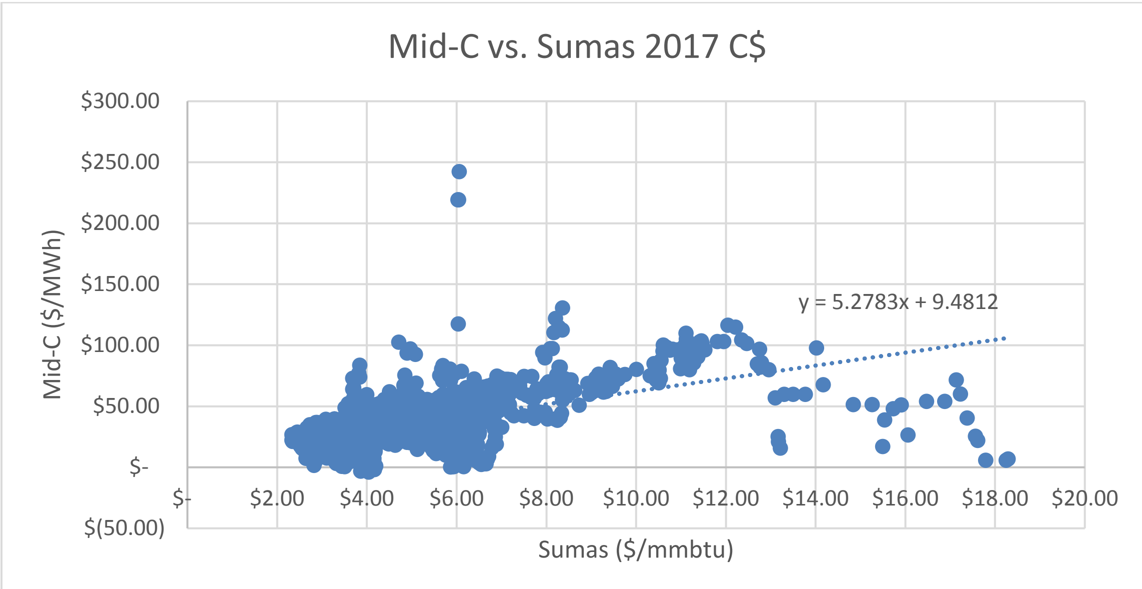


[12]

This figure implies that Mid-C prices are set by variation in the price of natural gas. However, this figure only takes into account the annual average price of each good. This biases the data to seem more correlated than they actually are.

Even worse, the BC Hydro graph only shows that nominal value of Mid-C and Sumas. These prices are set on a daily basis; if there is any correlation between the two, then we should see evidence of that in the daily price index.

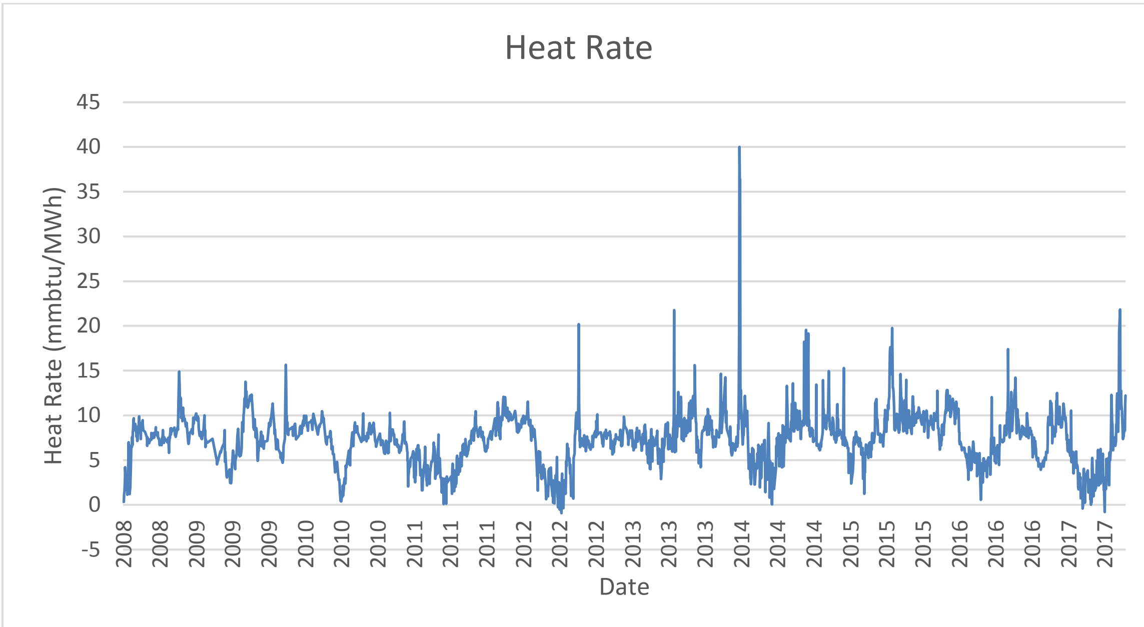
[12] British Columbia Utilities Commission Information Request No. 2.22.1 Dated: September 20, 2017 British Columbia Hydro & Power Authority PUBLIC Response issued October 4, 2017, page 13.



When looking at the daily market data, we immediately see that the price of natural gas is not the primary factor determining the price of Mid-C electricity. In fact, Sumas natural gas prices only explain 26% of the variance in Mid-Columbia prices.

Statistic	**Value**
R^2	.261158
Observations	2386
P-value	$6.5x10^{-159}$
Standard Error	16.62

We expect some amount of correlation between the two prices, but, even then, natural gas prices aren't well correlated with the daily price of Mid-C. Also, contrary to BC Hydro's claim is a highly variable heat rate (price of power/price of gas) when looking at daily market data.



The wild variances of implicit heat rates reflect many factors:

1. Alternative fuels
2. Imports and exports to neighboring hubs
3. Demand
4. Transmission constraints
5. Over-generation

Overall, this adds to the evidence that BC Hydro's Mid-Columbia price forecasts are poorly constructed.

Request No. 2.42.0:

Project finance is based on the fundamental premise that the buyer provides credit support to the developer. British Columbia Hydro appears to dispute this industry maxim:

> 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 rate-payers will pay.[13]

[13] British Columbia Utilities Commission Information Request No. 2.42.0 Dated: September 20, 2017 British Columbia Hydro & Power Authority Response issued October 4, 2017, page 3.

Simply stated, the power purchase agreement is the basis for the financing of a power project. The cost of capital is low for projects where the counterparty has the power of taxation and higher for projects sold to investor owned utilities.

Request No. 2.48.0:

British Columbia Hydro's forecast of the cost of utility scale battery projects is speculative – as is everyone's at this early stage in the development of the technology. However, while speculation is necessary when evidence is scarce, the market is providing actual data. The data does not support British Columbia Hydro's estimates:

> The estimated cost of capacity (unit capacity cost) for battery storage systems in 2040 is $651/kW-year ($2018), not including a cost of energy lost during charging/discharging inefficiencies. A portfolio analysis has been done that included the above battery storage systems (using a minimum project size of 100 MW) as well as pumped storage (using a minimum project size of 1,000 MW), however the model selects pumped storage as a lower cost option than batteries. Please refer to BC Hydro's response to BCUC IR 2.46.0 for further sensitivity analysis.[14]

Duke Energy's North Carolina subsidiary has recently filed for regulatory treatment for a 13 megawatt investment.[15] While Duke has a higher cost of capital, its project appears to provide for a much lower first year cost. Using industry standard assumptions from the most recent Lazard studies, Duke seems likely to be charging rate payers only US$289.62/MWh:

Cost of Capital	$	174.3
Depreciation	$	15.38
O&M	$	1.54
Total Cost	$	289.62

Request No. 2.63.0:

British Columbia Hydro appears to have submitted an erroneous value for the operating costs of onshore wind projects in British Columbia:

[14] British Columbia Utilities Commission Information Request No. 2.48.0 Dated: September 20, 2017 British Columbia Hydro & Power Authority Response issued October 4, 2017, page 2.
[15] http://www.utilitydive.com/news/duke-to-build-its-first-utility-scale-regulated-battery-storage-projects/505374/

> For a 100MW onshore wind project in B.C., the current capital cost at gate is estimated to be $2,360/kW for an ideal site, and $2,830/kW for a complex site (in the 2015 Wind Resource Options Update, 36 per cent of projects are considered complex). The operating cost is $73/kW-yr (or between **$17/MWh and $32/MWh** depending on the capacity factor) for onshore wind projects in B.C.[16] (Emphasis supplied.)

Although British Columbia Hydro's estimates of wind costs in previous submissions have compared poorly with actual data from elsewhere in Canada and the United States, these estimates appear to differ wildly on the other side of actual wind costs. Lazard estimates that the LCOE of onshore wind is C$39.50/MWh to C$77/MWh, which is still significantly lower than the LCOE for Site-C.[17]

[16] British Columbia Utilities Commission Information Request No. 2.63.0 Dated: September 20, 2017 British Columbia Hydro & Power Authority Response issued October 4, 2017, page 116.
[17] Lazard LCOE Analysis 10.0, December 2016. page 8.