BC Hydro
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October 18, 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: Project No. 1598922
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Site C Inquiry – Alternative Portfolios

BC Hydro writes to provide its comments on, and analysis of the BCUC's Alternative Site C Portfolios as requested by the Commission Panel in its letter of October 11, 2017 (**A-22**).

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/ma

Enclosure

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Site C Inquiry

BC Hydro Submission on the BCUC Alternative Portfolios

October 18, 2017

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Introduction

On October 11, 2017 the Commission provided a letter and attached spreadsheet requesting comment on three illustrative Alternative portfolios.

Overall BC Hydro believes that these portfolios make several assumptions regarding alternative resources that are either methodologically incorrect or unsupported. The combined cost impact of most of these incorrect or unsupported assumptions is estimated to be approximately $4 billion under-estimate of the present value costs of the medium load scenario for the October 11 portfolio.

Further, BC Hydro is concerned with the reliance in the October 11 portfolio on resources that are not commercially feasible. Resource planning based on low probability unproven assumptions is not good utility practice and poses an unacceptable risk to ratepayers due to the potential for inadequate supply and high cost resources.

Portfolio analysis is a complex undertaking for which BC Hydro has developed its methods over the past ten years. Attempting to simplify this analysis in the manner provided in the October 11, 2017 letter (A22) and spreadsheet (A-22-1) will result in inaccuracies and the potential for errors. BC Hydro's energy planning tools and processes have been tested in technical advisory committees, Commission proceedings, and other regulatory processes. We recommend the Commission exercise caution in attempting to replace this robust analysis with an alternate methodology that is oversimplified, untested and subject to errors.

In order to provide the Commission with the information needed to understand the impacts of alternative assumptions on Site C's cost effectiveness, we have reflected the Commission's requested assumption sensitivities in our analysis provided in the response to BCUC IR 2.46.0. **We continue to believe this represents the best estimate of the impact of these assumptions on the costs to ratepayers of Site C termination**.

As highlighted in this document, simplified assumptions of what resources compete with Site C, errors in the application of planning criteria and translation of input assumptions into resource costs can have substantial impacts on the costs of portfolios. Correcting the issues with the October 11 portfolio increases the present value cost of this portfolio by approximately $4 billion for the medium load scenario, and as a result cost comparisons based on this portfolio are not representative of the impacts to ratepayers of terminating Site C. While we have indicated how these errors may be addressed, we remain concerned that unidentified or new errors will occur with further application of this methodology.

Table 1 below summarizes BC Hydro's comments regarding the October 11 portfolio as well as approximate present value cost impacts if BC Hydro's concerns are addressed for selected items where BC Hydro has been able to conduct individual analysis. Each issue is discussed in further detail in the following sections.

Table 1 Summary of Concerns with October 11 Portfolio

Issue	Document Reference	Potential Present Value Cost Impact[1]
A) Treats DSM as an alternative when it is included in all portfolios. This effectively assumes we cease DSM if we build Site C, which is not correct.	A-22, page 2 and A-22-1 Sheet: Med LF – portfolio Cells: Row 16	$0.2 billion increase in cost of October 11 portfolio using Commission assumptions on cost of alternative resources. This would be a larger increase if more realistic cost assumptions are used for alternatives.
B) BC Hydro builds and finances all alternative resources. As BC Hydro has stated, we do not believe this is a realistic assumption.	A-22, page 5 (Financing costs, taxes)	$0.8 billion increase in cost of Oct 11 portfolio.
C) Battery costs used in the analysis omitted the following: – Capital costs other than balance of system (i.e. batteries, power conversion system, construction and permitting). – Operating costs of approximately $10M per year for a 100MW installation. – Operating energy losses of approximately 7%	A-22, page 2 and A-22-1 Sheet: Med LF - portfolio costs Cells: D12 and D13	$2.2 billion increase in cost of Oct 11 portfolio.

[1] Impacts have been estimated for the mid load scenario. Impacts may vary in the low load and high load scenarios.

Issue	Document Reference	Potential Present Value Cost Impact[1]
D) Capacity-focused DSM estimates are dated with significant deliverability risk	A-22, page 2 and A-22-1 Sheet: Med LF – portfolio Cells: Row 55	BC Hydro has not estimated an individual cost impact associated with this issue but expects the impact to be material.
E) Wind cost declines are optimistic.	A-22, page 7 (Wind – capital and O&M cost)	BC Hydro has not estimated a cost impact associated with this issue but expects the impact to be material.
F) Assumes Site C has less flexibility than a portfolio of alternative resources because of the size of Site C's reservoir. This is incorrect. The analysis fails to recognize Site C's flexibility is derived from Williston storage given Site C will be downstream with integrated operations.	A-22, page 8 (Shaping, Storage)	BC Hydro has not estimated a cost impact associated with this issue but expects the impact to be material.
G) Issues with assumptions regarding market pricing: • Uses the market forwards for pricing energy surplus rather than market forecast. Market forwards are not appropriate for this purpose. • Assumes any Site C surplus has same export value as alternative portfolio. This fails to recognize the additional value we expect to receive for flexible generation products in external markets.	A-22, pages 5-6 (Energy/Capacity surplus to BC Hydro need)	BC Hydro has not estimated a cost impact associated with this issue.
H) Other methodological issues: • Double-counting of loss savings associated with DSM • Use of Total Utility Cost rather than Total Resource cost to estimate costs to ratepayers • Application of a 14% reserve requirement to DSM energy savings • Failure to recognize Site C sunk and termination cost recovery in the alternative portfolio • Failure to recognize Site C surplus trade value over the period of analysis • Does not account for the overlap between credits for energy and capacity • Contains errors related to calculation of timing of DSM costs • Does not include network upgrade costs for wind resources • Assumes availability of cost-effective geothermal resources.	A-22 and A-22-1	BC Hydro has not estimated an individual cost impact associated with these issues but has included in our consolidated analysis.

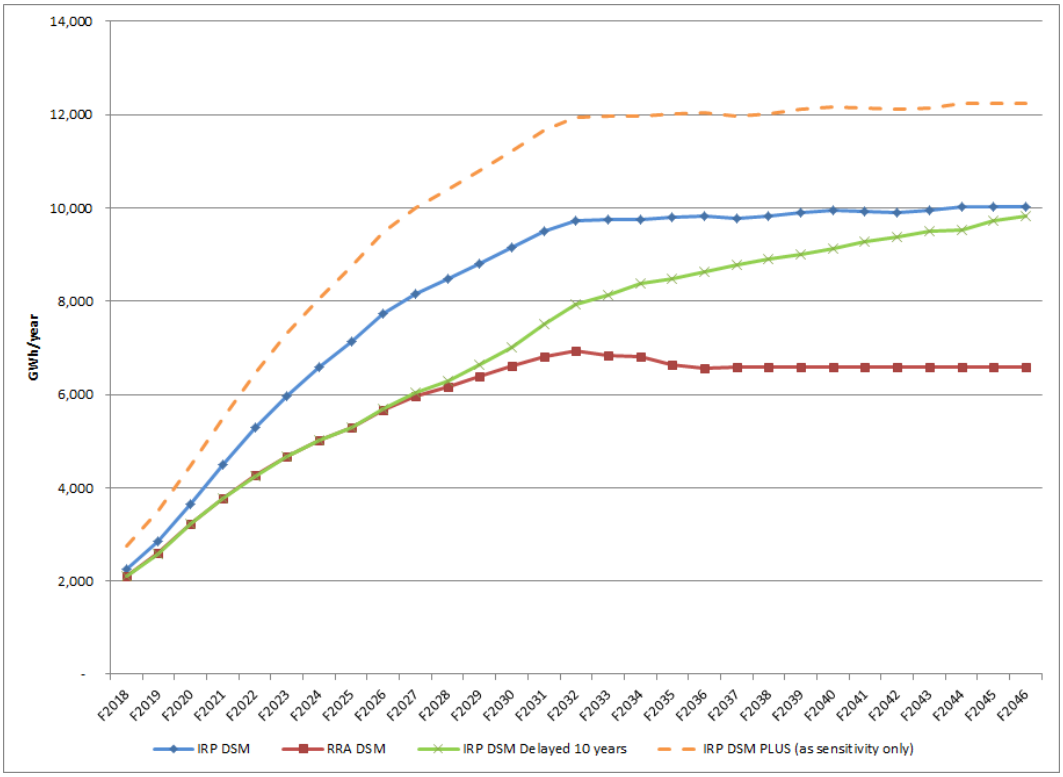
BC Hydro notes that the spreadsheet is complex and appears to have hard-coded data in the "portfolio" and "portfolio costs" sheets rather than working formulas (the "NPV" sheets have working formulas). This makes evaluation of the model more difficult as we cannot verify the calculations without reconstructing the formulas. As such, there remains the possibility of additional issues or errors in the model that BC Hydro has not identified here. In addition, we have focused our evaluation on the "Med LF" scenario. We have assumed, but not validated, that any issues with this scenario would be translated to the "Low LF" and "High LF" scenarios.

A) DSM is not an alternative to Site C

The alternative portfolio provided by the Commission in its letter of October 11, 2017 shows energy and capacity resources sufficient to replace Site C. However, in selecting alternative resources it relies on DSM options that will be undertaken with or without Site C. Comparing the October 11 portfolio to Site C effectively presumes that in a future with Site C additional DSM activities will not be pursued. This is not the case, and cost comparisons from treating DSM as if it would not proceed with Site C are not representative of the impacts to ratepayers of terminating Site C.

BC Hydro expects to pursue additional DSM with or without Site C. This is because, as discussed in section 5.2.4 of Appendix L of the August 30 Filing, at $57/MWh the levelized total resource cost of the IRP DSM plan is well below the cost of incremental alternative clean resources. As such, Site C will only change the timing of when DSM activities occur, not their overall level. Figure 1 (sourced from Figure L-1, Appendix L to the August 30 Filing) demonstrates the change in timing of DSM activities used in the mid load forecast analysis. In this scenario, the Clean Alternative Portfolio uses the "IRP DSM Plan" activity level and the Site C Portfolio uses the "IRP DSM Delayed 10 years" activity level. By 2047 the activity levels are approximately equivalent.

Figure 1 DSM Energy Savings (Including Loss Savings, Mid Estimate)

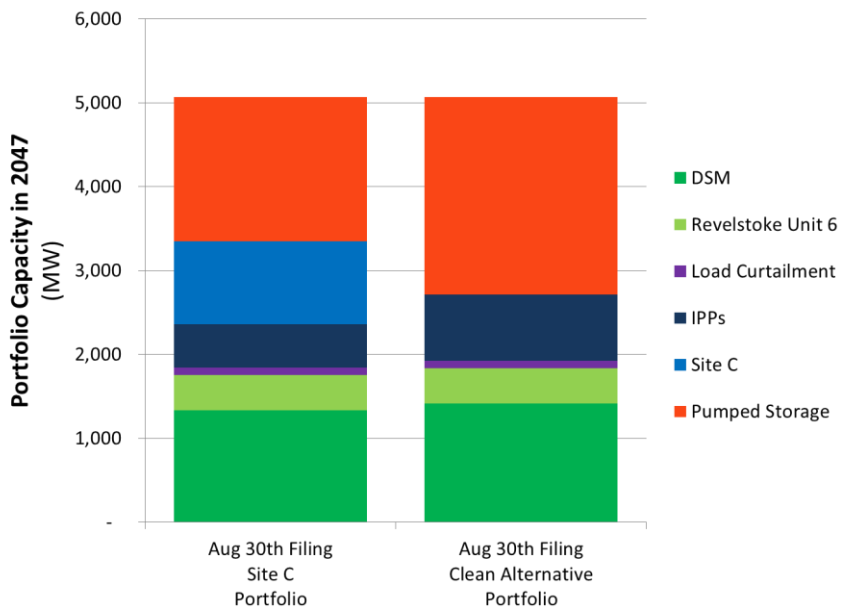


As highlighted by Mr. Reimann in our October 14, 2017 presentation, replacing Site C with incremental DSM may be representative of the short-term differences between portfolios (e.g., over a five-year timeframe), it is not sufficient for the long-term (e.g., years 6 to 70).[2] Figure 2 August 30 Filing Portfolio Compositions: Mid Load Forecast

compares the resources BC Hydro expects to use to meet domestic load growth over the next 30 years from a capacity perspective.

[2] Transcript Volume 14 (Technical Input Proceedings) page 1640.

Figure 2 August 30 Filing Portfolio Compositions: Mid Load Forecast



As shown, by 2047, there are several resources that are the approximately the same in both the Site C portfolio and the Clean Alternative Portfolio, as follows:

- Demand side management
- Revelstoke Unit 6
- Load curtailment

The major differences in resources between the two portfolios are:

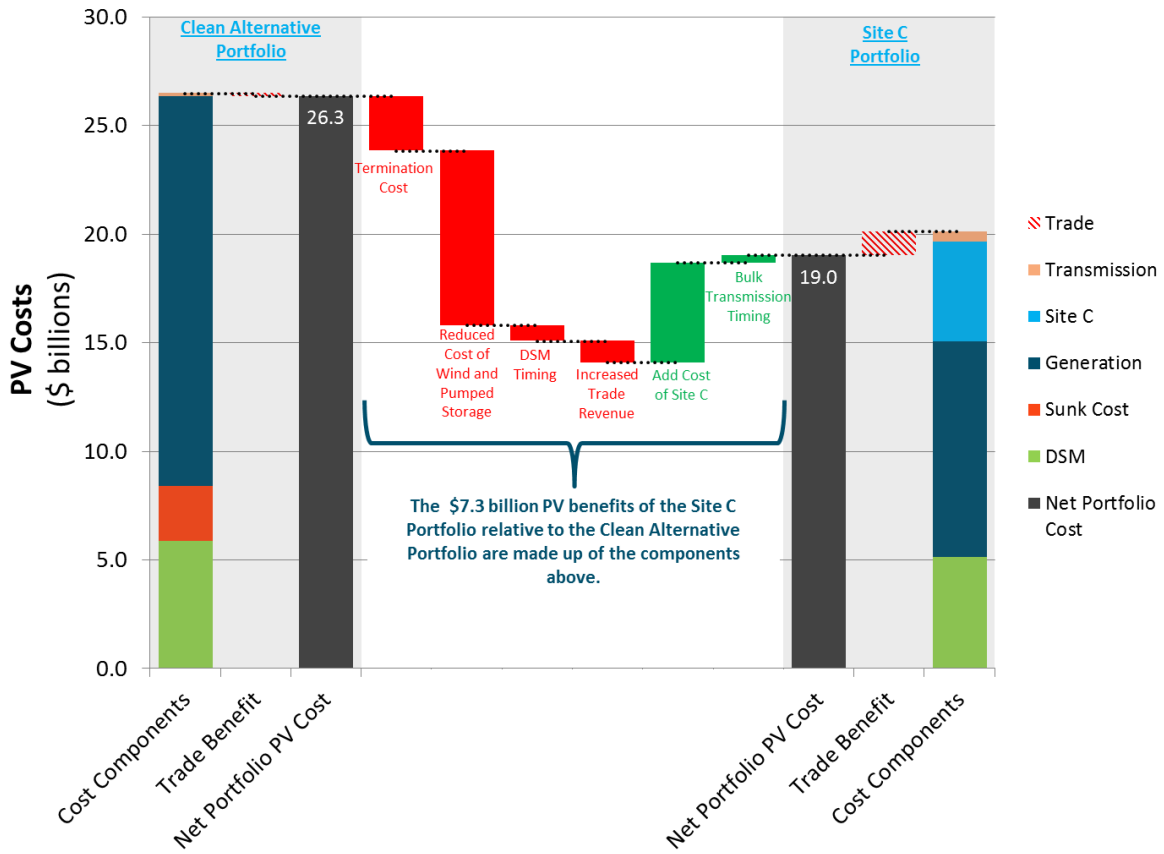
- Site C
- IPP energy resources (wind)
- Pumped storage

As one would expect, it is the major differences above that drive the differences in portfolio PVs.

Figure 3 shows the key components that form the basis of the $7.3 billion PV differential between the two portfolios identified in our August 30 Filing. The graph can be broken down into two key groups:

- The bars in the shaded areas under the headings "Clean Alternative Portfolio" and the "Site C Portfolio" demonstrate the incremental portfolio cost components of meeting the shortfall before DSM; the net trade value of each portfolio and the resulting net portfolio PV cost.
- The red and green bars between the two net portfolio PV costs show the breakdown of the key changes between the two portfolios. The red bars indicate reductions to portfolio costs and the green bars indicate increases to portfolio costs.

Figure 3 August 30 Filing Portfolio PV Components and Differences: Mid Load Forecast



As shown, the major difference in net portfolio PV costs results from:

- The cost of Site C net of termination costs; and
- The cost of wind and pumped storage resources.

As a result, wind and pumped storage are the true alternatives to Site C over the long term. The other three effects are DSM timing, trade revenue[3] and transmission

[3] The Site C portfolio has more trade benefits than the Clean Alternative portfolio. This is largely due to the short-term surplus created in F2025-F2031. In addition, we expect additional market value from surplus system capacity, flexibility and shaping that is not captured in our analysis.

resources,[4] all of which are relatively small. With respect to DSM, the Site C portfolio has a reduced DSM cost because by delaying the DSM ramp-up, the costs are also delayed. Therefore, the difference is largely the effect of discounting the incremental DSM cash flows over the DSM planned ramp up period.

In order to assist the Commission in their determinations, we have provided as Attachment 1 BC Hydro's costs of the two portfolios making up the comparison in Figure 3 above. Further, in Attachment 2 we have provided an update to the Commission's model to reflect the treatment of DSM as a timing consideration rather than an alternative and correcting other errors covered below. Isolating the correct treatment of energy-focused DSM results in portfolio costs approximately $215 million higher on a present value basis than in the October 11 portfolio.

This is relatively low because of problems with the assumptions made with respect to wind and battery resources resulting in costs only slightly higher than DSM resources. The impact of changes to the treatment of DSM would increase substantially with more realistic assumptions regarding the costs of alternative resources as outlined in the sections below.

B) IPPs are better suited to building and financing alternative resources

BC Hydro does not expect to finance alternative resources and cost comparisons that rely on the assumption that we finance IPPs are not representative of the impacts to ratepayers of terminating Site C. For over three decades, IPPs have been building run-of-river, wind and biomass resources in B.C. This is also the case worldwide. As we described in section 6.4.3 of our Reply Submission (F1-12) and our response to BCUC IR 2.42.0, this makes sense because each industry has specialized knowledge that makes them better suited for resource exploration and

[4] The Site C portfolio has some differences in portfolio costs related to advanced timing of bulk system transmission resources. This is because the Clean Alternative portfolio includes significant pumped storage in the Lower Mainland which serves to delay incremental transmission requirements.

development. If BC Hydro were to explore and build these types of resources, we will hold substantially greater risk associated with their construction and operations. Further, in many cases IPPs already own the rights to resource sites, and are unlikely to sell these sites without some of their expected return on equity.

As an example, Figure 6 later in this document shows potential future cost declines for wind projects. IPP financing of a wind project that enters service in F2028 is expected to result in costs 40 per cent higher than costs that use BC Hydro financing.

BC Hydro has calculated the impact of this assumption in our consolidated corrections to the A-22-1 spreadsheet provided in Attachment 4. Isolating the effect of financing shows that IPP financing will increase the present value costs of the October 11 portfolio by approximately $0.8 billion.

C) The full capital cost and losses of batteries must be accounted for

The October 11 portfolio analysis appears to make several errors with respect to the treatment of battery resources. The largest of these is in capital costs – the October 11 portfolio bases the estimated capital costs only on Balance of System costs, and does not include other capital costs including the cost of the batteries themselves which are the largest component of this resource's capital cost.

In addition to the above, the alternative portfolio**:**

- Does not reflect the 7 per cent energy losses associated with the battery recharge cycle; and
- Does not include expected operations and maintenance costs for batteries (approximately $10 million per year for a 100MW/1000MWh installation[5]).

[5] https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf.

In addition to the cost and loss assumption errors, we note that assuming 400MW of low-cost batteries by F2025 is very unlikely and is not considered commercially feasible. In the entire US, there was approximately 500MW of utility-scale lithium ion batteries installed at the end of 2016 providing an average of 1 hour of storage – this would be an effective capacity of approximately 50MW for a 10 hour storage product. In Canada there is a total of 23 MW of installed battery capacity.

Battery storage system capital costs are made up of the following four component costs:

- Balance of system (**BOS**)
- Battery cost
- Power conversion system; and
- Engineering, permitting and construction cost.

The Commission states that,

> Battery costs were estimated from a graph (figure 18, median line) in an August 2016 NREL report "Exploring the Potential Competitiveness of Utility-Scale Photovoltaics plus Batteries with Concentrating Solar Power 2015-2030." Costs were converted to Canadian dollars, and historical inflation estimates for F2015 to F2018 were taken from BC Hydro's resource options spreadsheet. A 10-year battery life was assumed.

The cited figure from the August 2016 NREL report[6] is shown as Figure 4 below. It depicts the estimated capital costs of only the BOS for storage systems.

[6] https://www.nrel.gov/docs/fy16osti/66592.pdf.

Figure 4 **August 2016 NREL Report: Estimated Battery Balance of System Costs, 2015-2030**

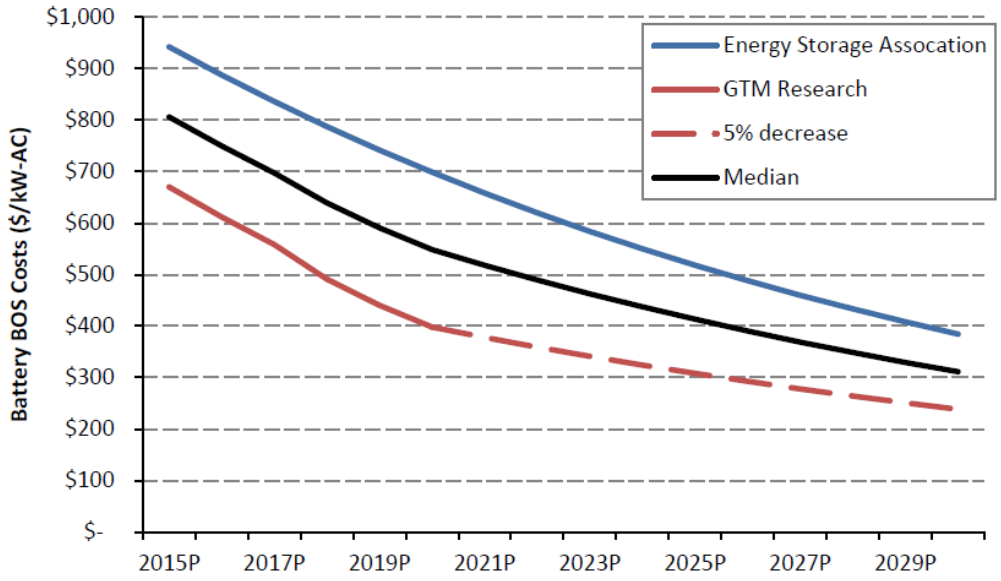


Figure 18. Estimated battery BOS costs, 2015–2030

Sources: GTM Research 2016; Roberts 2015

This figure does not include any of the other three cost components.

Table 2 summarizes the NREL and Lazard estimates of total installed cost for lithium-ion batteries in 2025, as provided in our response to BCUC IR 2.48.0. These costs include all four components of the installed cost described above for a ten-hour product over a 20-year life and do not include substantial annual operating and maintenance costs or the cost of battery recharge cycle losses.

Table 2 Total Installed Cost of Lithium-Ion Batteries (100 MW/1,000 MWh System)

Cost Component	NREL Unit Cost ($/kW)	Lazard Unit Cost ($/kW)
Batteries	5,000	6,260
Balance Of System[7]	800	Included in Battery Cost above
Power Conversion System	No information (assume equal to Lazard)	260
Other Costs – installation, commissioning, engineering, etc.	No Information (assume equal to Lazard)	910
Total Installed Cost ($US 2016)	**$6,970 (US)**	**$7,430 (US)**
Total Installed Cost[8] ($Can 2016)	**$8,643 (Can)**	**$9,213 (Can)**
Convert to 2018 dollars and include Commission assumed 18.75% cost decline to 2025	**$7,306 (Can)**	**$7,788 (Can)**

As discussed in our response to BCUC IR 2.48.0, pumped storage has a lower capacity cost than batteries and is therefore selected in our models as the preferred non-Site C capacity resource.

BC Hydro has updated the spreadsheet A-22-1 with corrected capital costs based corrected capital cost estimates and added in energy losses as well as operating and maintenance costs. Refer to Attachment 3. This increases the present value cost of the October 11 portfolio by approximately $2.2 billion (from $2.9 billion to $5.1 billion).

[7] Refer to Figure 2, median line for reference.

[8] 1US = 1.24 Can.

D) Capacity-focused DSM estimates are out-of-date and have significant deliverability risk

The October 11 portfolio includes over 400 MW from optional time of use rates and up to 500 MW from demand response programs. Some of this potential has been sourced from BC Hydro's draft 2012 Integrated Resource Plan[9] and was based on assumptions that have since become outdated, or been refined. Overall, the October 11 portfolio assumes there is:

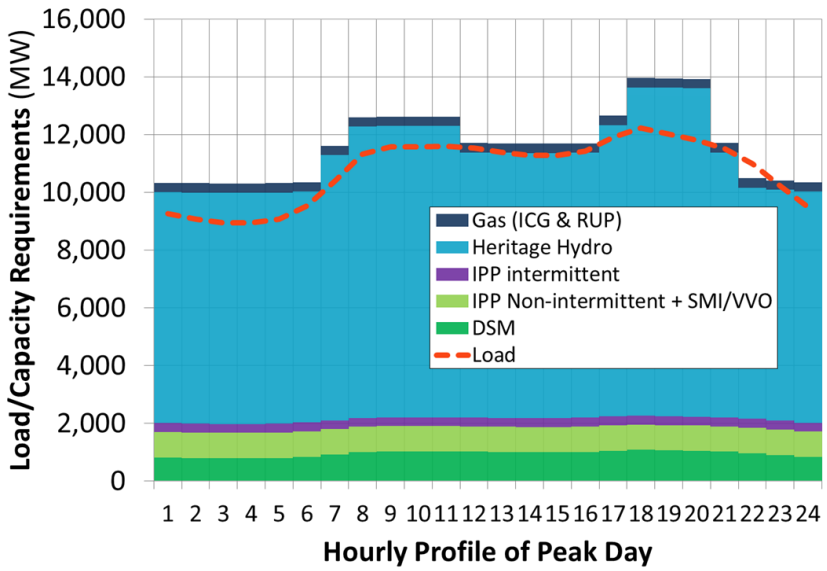
- Roughly twice the amount of capacity-focused DSM that BC Hydro believes is available (930 MW vs. 450 MW); and
- The capacity-focused DSM is at prices 70 per cent lower than BC Hydro believes is likely ($15/kW-year vs. $50/kW-year using Total Utility Cost – the gap is slightly larger when Total Resource Cost is used).

BC Hydro has provided updated estimates of potential capacity-focused DSM savings in our response to BCUC IR 2.73.0. While there remains significant deliverability risk with these updated estimates, we believe they are more realistic than the outdated information from the draft 2012 IRP. We believe higher levels of capacity-focused DSM are not commercially feasible.

One of the key findings since the draft 2012 IRP has been the requirement for a minimum ten-hour capacity product and not the four-hour product contemplated in the draft 2012 IRP. Figure 5 demonstrates how BC Hydro's peak capacity resources compare to BC Hydro's load shape on a day during a winter cold snap.

[9] The Commission sources this information from one of the submissions of Philip Raphals to the Joint Review Panel (provided by West Moberly and Prophet River First Nations in F28-2). BC Hydro provided a rebuttal report in response to submissions of Philip Raphals available at http://www.ceaa.gc.ca/050/documents/p63919/97291E.pdf.

Figure 5 BC Hydro's Hourly Load and Capacity Profile for Peak Day



The periods when the sources of supply are closest to the load extend from the morning (6 a.m.) through to the late evening (11 p.m.) and include the shoulder time between the morning and evening peak loads. This means that if the load were to increase in a uniform manner across all hours, there is the potential to be short during these times. As a result BC Hydro needs a minimum ten-hour product to deal with shortfalls. Refer to the response to BCUC IR 3.19.0 for further discussion.

The key differences between the current analysis and the draft 2012 Integrated Resource Plan include:

- **More recent research shows that the TOU response by General Service (i.e. commercial and light industrial) customers may not reach the levels contemplated in the draft 2012 Integrated Resource Plan:** The 400 MW estimate in the draft 2012 IRP assumed that 30 per cent of general service customers achieved capacity savings through optional time based rates. Response by general service customers accounted for almost half (185 MW) of the 400 MW estimated impact. Research and experience since 2012 indicates that general service customers may be less responsive to such complex pricing

schemes than other customers. Given this more recent knowledge, our refined estimate of savings from time based rates among general service customers reflects 13 per cent participation[10] rather than 30 per cent participation. For example,

- *Analysis of Ontario's Full Scale Roll-out of TOU Rates – Final Study, for Ontario's Independent System Operator, February 2016*, found that: "General service class customers show little evidence of load shifting behavior and are less responsive to the TOU prices than residential customers."[11]
- Likewise, *Evaluation of the Large and Medium General Service Conservation Rate, for BC Hydro, January 2015* found that "Only a small portion of [general service] customers were able to correctly identify their rate structure…." And that that "various inputs to the rate…. were perceived as too difficult for customers to measure and manage themselves".

- **The draft 2012 Integrated Resource Plan's time-based rates estimates included rate designs that provided capacity savings over limited durations which on their own would not be not sufficient to meet BC Hydro's peak capacity requirements:** The 400 MW estimate included approximately 140 MW of capacity savings assumed to be obtained through Critical Peak Pricing, which imposes a very high price for electricity consumed during the critical peak event. Critical Peak Pricing tariffs usually allow for a short duration and limited number of events per year. For example:
  - Southern California Edison allowed for 12 Critical Peak events per year of four hours each.[12]

[10] This participation estimate was based on Brattle Group's Pricing Program Database (PacifiCorp Demand Response potential Study; Vol. 5; Class 1&3 Appendix; February 2017).

[11] The study's definition of "General Service" is equivalent BC Hydro's small general service customers and the smaller of our medium general service customers.

[12] Cal. PUC Sheet No. 60078-E, Rate Schedule TOU-D effective September 30, 2016.

- San Diego Gas & Electric Company allowed for 18 Critical Peak events per year, at seven hours each.[13]
- Xcel energy in Colorado allowed for 15 critical peak events per year, at four hours each.[14]

As a result of these restrictions, the timing and availability of capacity savings from critical peak pricing is limited, and other supply and demand side resources are more likely to be pursued. Given this limitation, BC Hydro has not included critical peak pricing in our refined estimate of savings from time based rates that was presented in our response to BCUC IR 2.73.0.

- **The October 11 portfolio assumes more demand response savings than are available:** BC Hydro is uncertain of the source of the 500 MW demand response estimate. The 2012 draft Integrated Resource Plan shows approximately 250 MW of potential by F2032 so it is unclear what the basis is for the October 11 portfolio's estimate of up to 500 MW of demand response programs. Since the draft 2012 Integrated Resource Plan we have better information on demand response technologies as a result of our pilot activities in this area showing 210 MW of potential savings, which has been reflected in the estimates provided in the response to BCUC IR 2.73.0..

Table 3 provides BC Hydro's refined estimates of optional time based rates savings, load curtailment and demand response, as provided in our response to BCUC IR 2.73.0. As shown:

- Available volumes are roughly half of the 930 MW that have been included in the October 11 portfolio.
- Pricing is over three times the effective cost of capacity DSM used by the October 11 portfolio (calculated to be $15/kW-year from spreadsheet A-22-1).

[13] California Public Utility Sheet No. 21479-E, effective January 1, 2010.
[14] COLO. PUC No. 8 Electric, Rate Schedule PG-CPP effective January 2017.

Table 3 Estimated Capacity Savings from BC Hydro's Capacity Focused DSM Programs

	Estimated Capacity Savings (MW)		Levelized Costs ($/kW-year)	
	in F2023	in F2027	TUC	TRC
Direct Load Control Programs (Res, SGS, MGS)	170	210	55	70
LGS Load Curtailment	100	120	75	60
Time of Use Rates (all classes, incl. EV)	80	120	10	10
Total	**350**	**450**	**50**	**55**

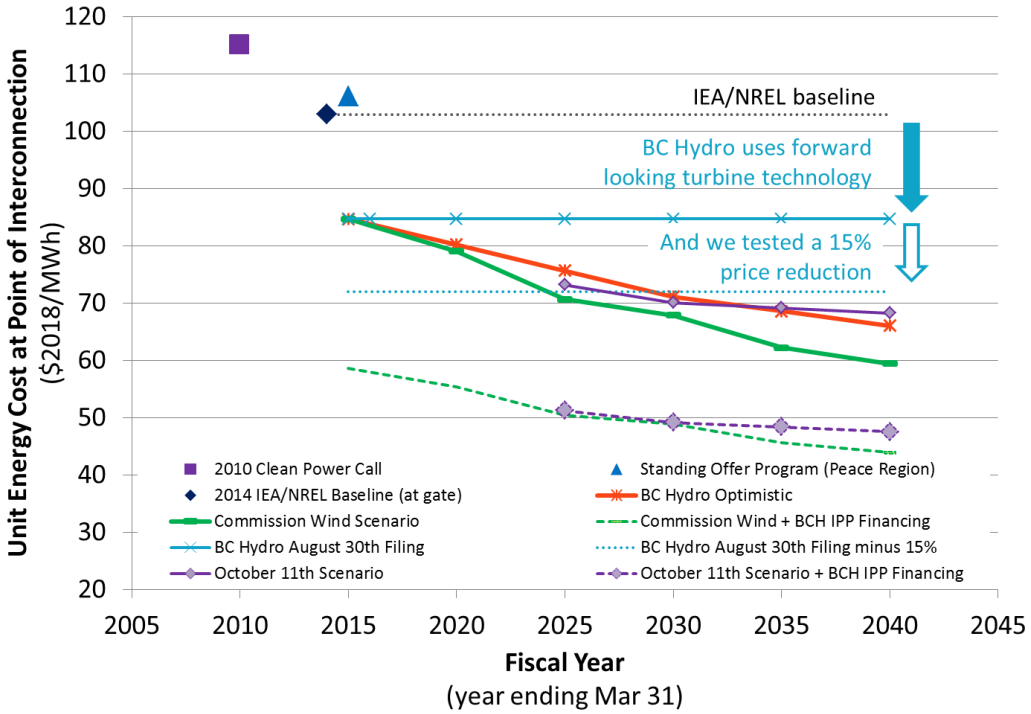
These assumptions were included in the capacity focused DSM values modelled in BC Hydro's Optimistic Portfolio Sensitivities described in our response to BCUC IR 2.46.0. These potential savings may grow beyond F2027 (as much as 133 additional MW) as electric vehicle penetration increases.

We note that these volumes and prices come with substantial deliverability and cost risk as they make assumptions regarding uncertain future customer response. Portfolios which rely on these resources will have higher availability risk overall. BC Hydro does not believe these resources are sufficiently certain to include in our resource stack, and thus did not include these resources in our August 30 Filing analysis. We have tested the inclusion of these resources in our Optimistic Portfolio Sensitivities.

E) Wind cost declines are below median estimates

As described in the response to BCUC IR 2.44.0, BC Hydro examined an optimistic wind cost decline in our BC Hydro Optimistic Portfolio sensitivities. Figure 6 demonstrates a comparison of wind costs from recent acquisition processes relative to our current wind cost scenarios presented in BC Hydro's August 30 Filing and the sensitivity analyses described in the response to BCUC IR 2.44.0.

Figure 6 Wind Cost Decline Assumptions



BC Hydro's August 30 Filing included sensitivity analysis with a 15 per cent reduction in our forward-looking price for wind. BC Hydro's Optimistic Portfolio sensitivity assumes that future B.C. onshore wind unit energy costs drop by 16 per cent, 22 per cent and 27 per cent by 2030, 2040 and 2050, respectively. Figure 6 demonstrates that the October 11 scenario is very similar to BC Hydro's Optimistic Portfolio Sensitivity provided in the response to BCUC IR 2.46.0. The decline represents a 36 per cent reduction in unit energy cost since the 2010 Clean Power Call by fiscal 2025.

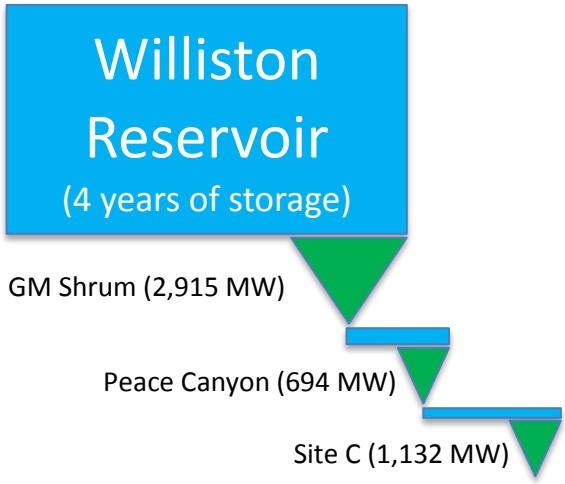
F) The Williston Reservoir is the key source of Site C's seasonal shaping capability

The October 11 portfolio description states that "The Site C reservoir does not have sufficient storage volumes to provide seasonal shaping of generation. The Alternative Portfolio also does not provide seasonal shaping of generation." This

assessment of Site C is incorrect. Site C has seasonal shaping and firming capabilities, primarily due to its location downstream of Williston Reservoir (rather than due to the Site C reservoir itself).

Figure 7 shows that Williston Reservoir provides over four years of storage capability and can be used for seasonal shaping of generation at Site C. Outflows from Williston go through Peace Canyon and will go through Site C, with only minor delays (refer to the response to BCUC IR 2.22.6 for the Site C monthly generation profile). As a result, the seasonal shaping benefits of the Williston Reservoir will also apply to Site C.

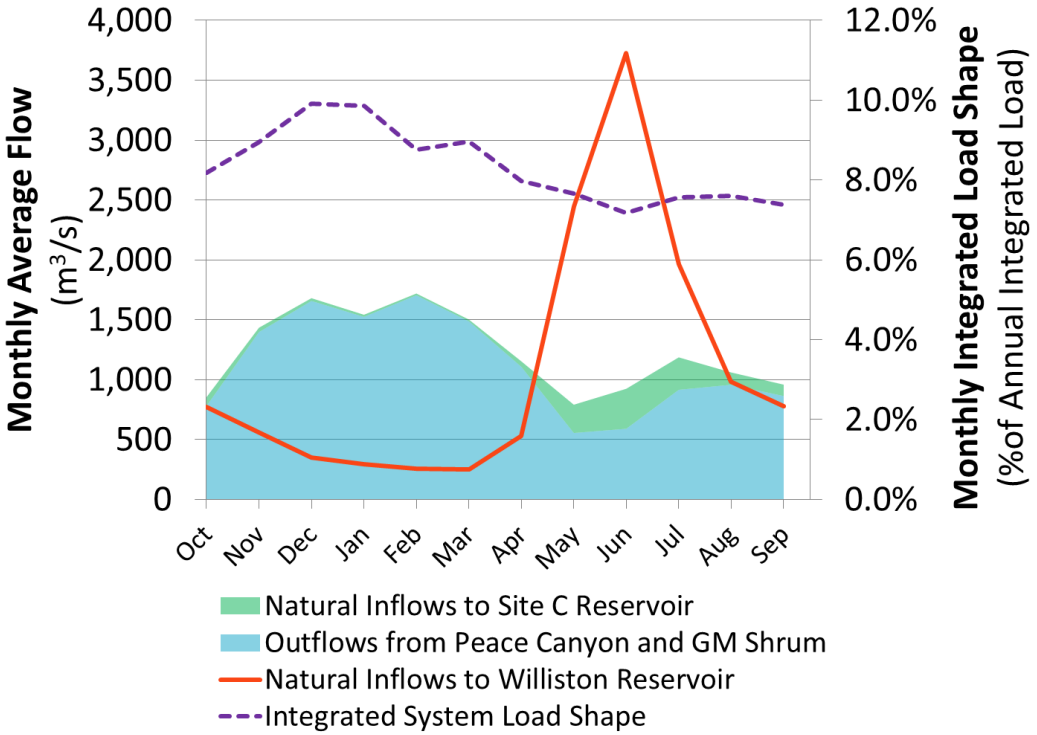
Figure 7 Peace River System



When GM Shrum is operating, BC Hydro also operates Site C and Peace Canyon in a similar manner to ensure coordination between the projects. BC Hydro shapes the operation of these projects to high value periods according to system needs and surplus value.

Figure 8 demonstrates that the inflows into Williston are shaped into high value periods in the winter to match BC Hydro's monthly load profile – i.e. Site C inflows are already seasonally shaped.

Figure 8 Monthly Inflows to the Site C Reservoir



Site C generation enhances the value of the storage in Williston Reservoir and adds to overall system seasonal firming and shaping capability. In addition, the Site C reservoir provides both daily and multi-day firming and shaping benefits that can be used to integrate intermittent wind and solar resources. The seasonal shaping and firming benefits of downstream reservoirs are seen today at our existing facilities at Peace Canyon and Revelstoke.

G) Issues with market price assumptions

1. The forward price is not a long-term price forecast

The October 11 portfolio assumes a fiscal 2025 forward market price for Mid-C power of $30/MWh (USD) to apply to surplus spot market energy sales in their portfolio analysis. The forward market curve is a record of real short term electricity transactions that are completed to lock in prices. This is not, however, a market price forecast for the following key reasons:

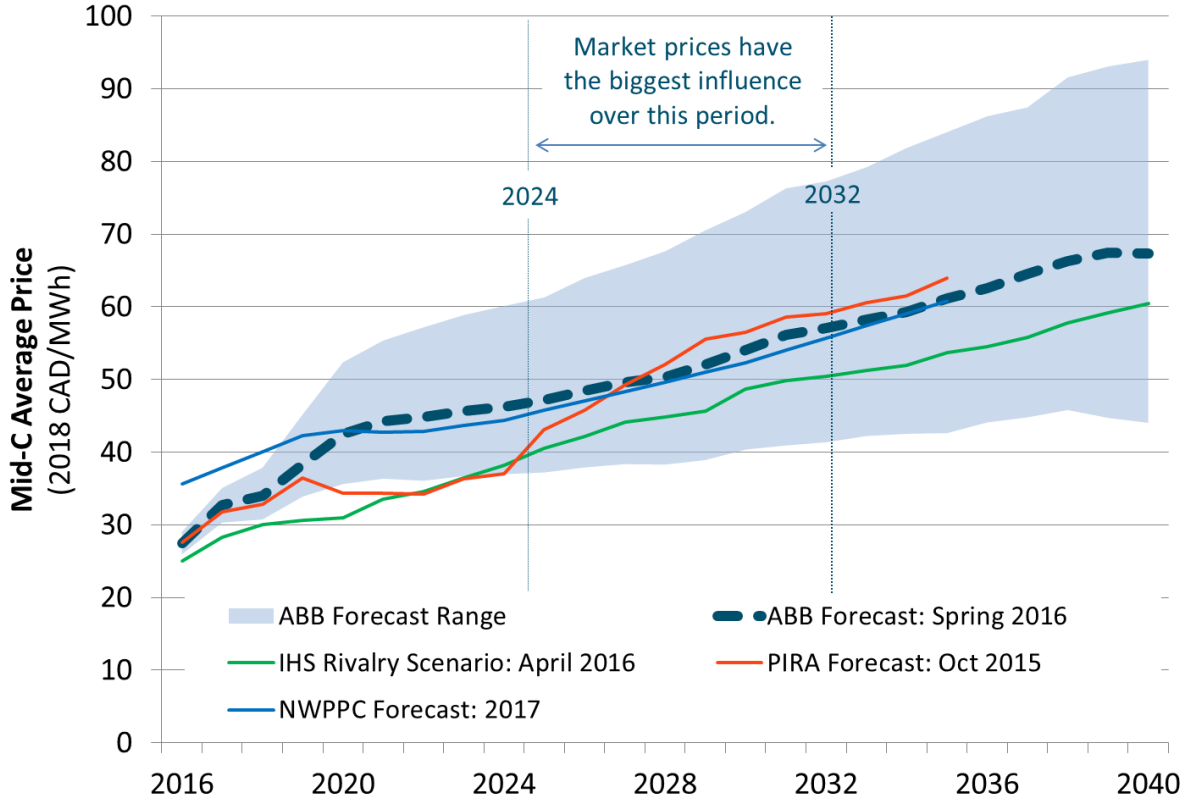
- As discussed by Mr. Bechard on October 14, 2017 the number of transactions for electricity in later years (e.g., in fiscal 2025) declines significantly because customers today aren't as willing to commit to prices so far out in time. As a result, forward prices for a year such as fiscal 2025 are not representative of the highly liquid Mid-C spot electricity market prices that are expected to be seen in fiscal 2025; and
- Forward prices are established based on what participants are willing to pay today for price certainty, rather than their true expectations of future market fundamentals and prices.

As discussed in BC Hydro's response to BCUC IR 2.22.1, BC Hydro subscribes to the ABB reference case which simulates the operation of over 40 locations in the WECC to determine the market clearing price on an hourly time step. For each region, the ABB model considers:

- Individual power plant characteristics including heat rates, start-up costs, ramp rates, and other technical characteristics of plants;
- Transmission line interconnections, ratings, losses, and wheeling rates;
- Forecasts of resource additions (including renewable resources and pricing declines) and fuel costs over time;
- Forecasts of loads for each utility or load serving entity in the region; and
- The cost and availability of fuels that supply the plants.

ABB's reference case is used by over 100 customers worldwide. Figure 9 below demonstrates that the ABB reference case forecast for the Mid-C market is in the range of three other Mid-C market price forecasts and is well above the $37.60/MWh ($2025 CAD) that is adjusted to $25/MWh ($2018 CAD, adjusted for wheeling and losses) and used in the October 11 portfolio.

Figure 9 Mid-C Average Price Forecast Comparison



In addition, these comparator forecasts shown in Figure 9 are all higher than the "Low Market Price" scenario (shown as the bottom of the "ABB Forecast Range") which was tested in the BC Hydro Optimistic Portfolio Sensitivities and the Commission Portfolio Sensitivities provided in BC Hydro's response to BCUC IR 2.46.0.

2. BC Hydro expects to market capacity products at a premium

While BC Hydro is pursuing Site C to serve domestic load, it is expected that any short-term surplus energy and capacity will have additional value over and above what is currently captured by our long-term market forecast. As discussed by Mr.

Bechard in our October 14, 2017 presentation to the Commission, the clean, flexible capacity offered by Site C is expected to be increasingly needed in western markets as renewable resources (wind and solar) replace base load resources, such as coal and nuclear generation. These benefits are in addition to the value provided on Site C capacity in BC Hydro's portfolio modelling.

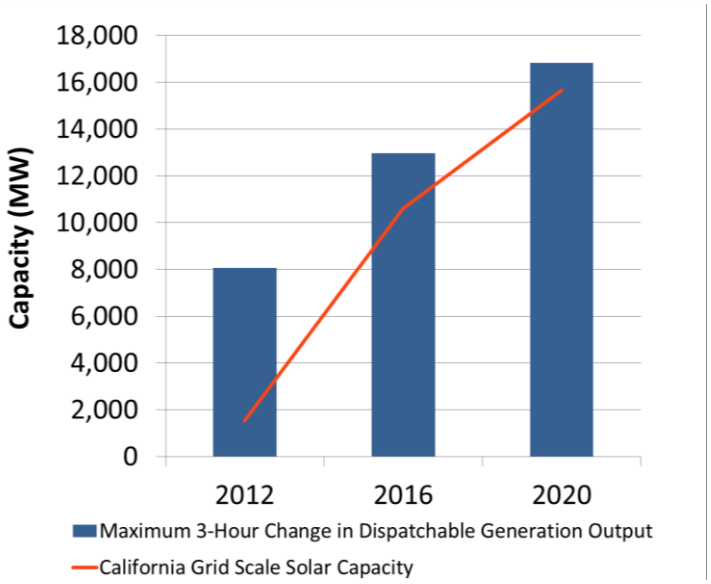
In terms of surplus markets, BC Hydro and Powerex are seeing significant retirements from western base load coal, nuclear and natural gas resources in the next ten to 15 years. For example:

- Pacific Northwest: over 2,500 MW of coal generation shut down by 2025;
- Alberta: over two-thirds (>6,000 MW) of coal generation shut down by 2030; and
- California: 7,500 MW of nuclear and natural gas generation shut down by 2025.

With significant regional renewable energy targets, much of this generation will be replaced with renewable resources which provide limited reliable capacity and require flexible backup capacity to respond to changes in generation. With the increased penetration of such variable resources, Alberta and California are looking to develop new markets for capacity and flexibility, respectively.[15] Figure 10 demonstrates the growing requirement for flexible, dispatchable capacity in California in response to increased solar generation penetration.

[15] Refer to the response to BCUC IR 2.22.1.

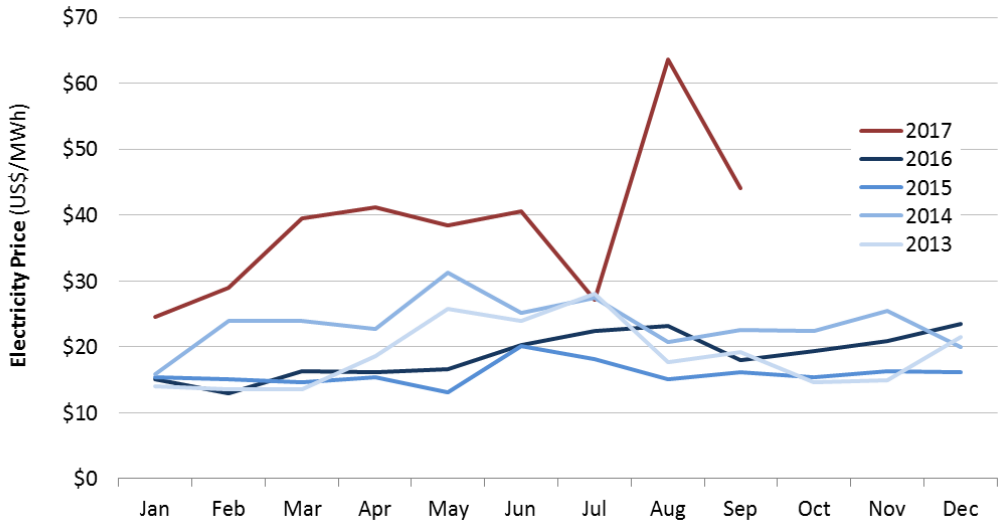
Figure 10 Solar Generation Penetration and Dispatchable Generation Requirements in California



This flexibility is particularly important for solar because the time when the sun goes down in California coincides with an increase in peak load, amplifying the need for dispatchable resources that can increase generation quickly as more solar resources are added to the system. For wind, the dispatch requirement is more to respond to intermittency within the hour – Site C can also provide this flexibility.

Powerex can provide up to 2,500 MW of the identified need using its existing transmission rights to California and its sources of flexible generation, including Site C. Figure 11 below demonstrates the monthly averages of price differences between the highest priced four hours and lowest priced four hours for each day from the California Independent System Operator (CAISO). It shows that 2017 is starting to see some significant growth in pricing differentials which aligns to the trends forecasted in Figure 10.

Figure 11 CAISO Intra-day Price Volatility (Average Difference between Highest Prices Four Hours and Lowest Priced Four Hours by Day)



As discussed above, the storage behind Williston Reservoir will allow Site C generation to preferentially use and store water at appropriate times of the day to take advantage of these differentials during the day and during the year. Based on this higher premium for flexible resources, portfolios including Site C would expect to obtain higher prices on market exports than portfolios excluding Site C.

H) Other Methodological Issues

BC Hydro notes that there are several other methodological issues with the assumptions in A-22 and the calculations in the A-22-1 spreadsheet.

1. **The energy-focused DSM volumes double-count loss savings.**

   - As stated in A-22 on pages 6 to 8, the October 11 spreadsheet applies 11 per cent loss savings on top of the volumes provided by BC Hydro in the response to BCUC IR 2.64.0.
   - The volumes provided in BCUC IR 2.64.0 already included loss savings. As stated in BCUC IR 2.64.0:

> *"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."* (emphasis added)

- Thus the October 11 portfolio has applied the 11 per cent gross-up factor twice. This over-estimates DSM savings by approximately 380GWh/year by year 20 of the analysis period.

2. DSM costs use the Total Utility Cost rather than the Total Resource Cost

- A-22 states on page 7, "…societal costs/benefits of energy efficiency DSM have not been included" and "The cost of energy efficiency DSM has therefore been included at the utility cost to BC Hydro…". BC Hydro notes that the costs included in the Total Resource Cost are real direct costs to its ratepayers from either rate impacts or customer costs of implementing DSM. Refer to the response to BCUC IR 2.64.0 for further discussion on why Total Resource Cost is the appropriate metric to use for comparing resource options.
- The impact of utilizing Total Utility Cost rather than a Total Resource Cost is an under-estimation of the present value cost to ratepayers of the DSM portfolio of $220 million over the period to 2047. This under-estimation will increase for longer analysis periods.
- As reference in the response to BCUC IR 2.64.0, 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]

3. **The portfolio applies a 14 per cent reserve requirement to DSM**

   - BC Hydro uses a 14 per cent reserve requirement on capacity from generating resources (e.g., Site C or wind). However, we do not require the 14 per cent extra from demand side resources (such as energy focused DSM) – rather, we treat DSM and its uncertainty as an offset to load.
   - Note that we expect greater deliverability risk associated with capacity focused DSM than energy focused DSM. As such, we expect to apply a planning reserve requirement from capacity focused DSM.
   - As a result, the October 11 portfolio has more DSM capacity resources than would be required under BC Hydro's planning criteria to replace a generation resource such as Site C.

4. **Any comparisons to Site C must include recovery of sunk and termination costs and trade revenues**

   - The October 11 portfolio does not include the recovery of Site C sunk costs, nor the costs associated with termination of the Project and remediation of the site. These are costs that occur in any Site C termination scenario, and should either be added to the alternate portfolio or subtracted from the cost of the Site C portfolio.

5. **Surplus energy value must be applied to Site C to allow for a comparison with the October 11 portfolio.**

   - As stated in A-22 on page 5, the October 11 spreadsheet calculates surplus energy revenue for energy that exceeds the gap to fill and is surplus to BC Hydro requirements. BC Hydro notes that a Site C portfolio would also have surplus energy revenues during the period F2024 through to F2031, when Site C energy is surplus to BC Hydro requirements. Any comparison of the October 11 portfolio to Site C should include a credit for

the value of any surplus energy as has been done for the October 11 portfolio.

6. **Overlap between energy and capacity credits**

   - As stated in A-22 on page 6, the October 11 spreadsheet applies a 50 $/kW-year credit to any capacity of the Alternative portfolio that exceeds the capacity required to fill the load resource gap and is used to meet BC Hydro's domestic load requirements. The October 11 spreadsheet also proportionately reduces the cost of the October 11 portfolio if the energy of the October 11 portfolio exceeds the gap and is used to meet BC Hydro's domestic load requirements. These two adjustments are calculated independently and credited additively. This applies a capacity credit to the full-size portfolio, failing to recognize that the proportional reduction done for energy would also reduce the capacity credit by the same proportion.

7. **Error in timing of DSM costs**

   - BC Hydro notes that the October 11 spreadsheet has erroneously applied DSM costs one year later than the associated savings. This understates the cost of the October 11 portfolio.

8. **Wind resources will require network upgrade costs**

   - Network upgrade costs are the costs of upgrades required between the point of interconnection of a new resource and the bulk transmission system. These costs must be added to the overall cost of alternative resources. BC Hydro has estimated the network upgrade costs for resources with low capacity factor (e.g., wind, run-of-river) to be $6/MWh

and for resources with high capacity factor (e.g., biomass, geothermal) to be at $3/MWh.[16]

- In comparison, Site C interconnects directly to the bulk system and the associated network upgrade costs are already included in its cost estimate. Similarly for pumped storage, BC Hydro has already included network upgrade cost into its cost estimate at point of interconnection because the 1000 MW facilities modeled are expected to interconnect directly to the bulk system.

9. Assumes availability of cost-effective geothermal resources

- BC Hydro continues to believe that relying on assumptions regarding inexpensive geothermal resources is inconsistent with good utility practice given the lack of commercially proven resources in B.C. Refer to the response to BCUC IR 2.61.0 and Appendix L to our August 30 Filing.
- BC Hydro notes that the two Borealis geothermal projects that Ms. Thompson (CanGEA) stated have 81 MW confirmed at a P90 level[17] have not yet drilled a well.

[16] These estimates are based on weighted average of network upgrade cost from the Clean Power Call results (2010). Network upgrade costs were provided in the interconnection studies conducted for each project in the Clean Power Call.

[17] Transcript Volume 14 (Technical Input Proceedings) pages 1497-1498

Consolidated Analysis of Identified Issues

BC Hydro has modified the October 11 spreadsheet (A-22-1) to address the consolidated effect of the following issues:

- Inclusion of DSM in the analysis as a timing consideration rather than a true alternative to Site C.
- Application of IPP finance costs to alternative resources rather than BC Hydro finance costs.
- Correction of battery costs to include the omitted capital components, energy losses, and operating costs, with an option to utilize pumped storage capacity costs instead.
- Correction of most of the methodological issues identified in section H.

This spreadsheet is provided as Attachment 4, and demonstrates that the consolidated impact of these corrections is estimated to be $3.9 billion. This analysis has been done on a preliminary basis only to demonstrate the magnitude of the impacts of these changes. This analysis is not intended to replace BC Hydro's existing portfolio analysis provided in the August 30 Filing and in the response to BCUC IR 2.46.0.

This analysis includes a switch of the capital cost for non-DSM capacity resources to be based on pumped storage rather than battery costs. Batteries are substantially more expensive than pumped storage even with potential future cost declines, and had this change had not been made the October 11 portfolio present value costs would have increased by $9.9 billion rather than $3.9 billion.

Conclusion

The October 11 portfolio is not a portfolio of commercially feasible generating projects and demand-side management initiatives that provides similar firming, shaping, storage, grid reliability, and greenhouse gas benefits at a similar or lower cost than a portfolio including Site C provides. As shown in this response, the October 11 portfolio is:

- More expensive than a portfolio with Site C.
- Includes resources that are not commercially feasible.
- Does not provide the same firming, shaping, and storage capability as Site C.

In response to section 3(b)(iv) of the terms of reference, BC Hydro has developed portfolios of commercially feasible generating projects and demand-side management initiatives at optimistic prices and provided portfolio unit energy costs in our responses to BCUC IRs 2.46.0 (with assumptions shown in BCUC IR 2.44.0). That analysis showed that these portfolios are all more expensive than Site C, even with significant Site C cost overruns and low load growth.

Site C Inquiry
BC Hydro Submission on
the BCUC Alternative Portfolios

Attachment 1

BC Hydro Portfolio Cashflows

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

Site C Inquiry

BC Hydro Submission on

the BCUC Alternative Portfolios

Attachment 2

October 11 Portfolio with
Corrected Treatment of DSM Energy Savings

Site C Inquiry

BC Hydro Submission on

the BCUC Alternative Portfolios

Attachment 3

October 11 Portfolio with Correct Battery Costs, Losses, and Operating Costs

Site C Inquiry

BC Hydro Submission on

the BCUC Alternative Portfolios

Attachment 4

October 11 Portfolio with Consolidated Corrections