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October 20, 2017

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Sirs/Mesdames:

Re: Site C Inquiry – Comments on the Alternative Portfolios

We are counsel for the Commercial Energy Consumers Association of British Columbia (the "CEC"). The CEC filed comments on the Alternative Portfolios on October 18, 2017. Upon our review of the submission, an error was identified in regard to its submissions on "Battery Costs" at pages 1 through 5. We have corrected the error and attach a replacement blacklined and clean copy of the submission for filing with the Commission.

The CEC understands the Commission may not accept the revision for filing given concerns around tight deadlines in this proceeding, but submits it is important that accurate submissions are before the Commission and did not feel it appropriate to ignore the error.

We apologize for any inconvenience this may have caused.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jj
cc: CEC
cc: Registered Interveners

Commercial Energy Consumers Association of BC (CEC)

Comments on the Alternative Portfolio

INTRODUCTION

In Exhibit A-22, the BC Utilities Commission (BCUC or Commission) invites comments regarding three Illustrative Alternative Portfolios developed by Commission staff to replace Site C energy and capacity. The illustrative Alternative Portfolios are designed to replace only Site C energy and capacity used for domestic consumption, and do not include generation built for the purpose of export.

The Commission notes explicitly that the illustrated Alternative Portfolios are provided for the purposes of soliciting feedback only. No findings have been made by the Panel regarding the assumptions used in the model or the general approach used.

CEC SUMMARY COMMENTS

The CEC agrees that it is highly appropriate for the Panel to avoid making the findings with regard to the appropriateness of the Alternative Portfolios at this time given the lack of information and understanding regarding the fundamentals of energy and capacity planning. However, the CEC submits that the development of the Alternative Portfolio represents an important step in the assessment of Site C and could be further examined with additional evidence and costing information to ensure the validity of the information.

The CEC recommends, that when advising the government, the Panel provide cautionary notes as to the value of the Alternative Portfolios until further analysis can be completed by system planning experts

The Panel invites comments from BC Hydro and other parties on these Alternative Portfolios of generating projects and demand-side management (DSM) initiatives; in particular:

- The underlying assumptions regarding the Alternative Portfolios; and
- The calculations, inputs and assumptions used in the Alternative Portfolio Spreadsheet.

The CEC is concerned with several of the assumptions and calculations that the Commission staff employed in their development and analysis of the Alternative Portfolio.

The CEC finds that the Commission Staff calculation of the net present value of the Alternative Portfolio at $2.889 billion contains significant error and grossly underestimates the cost of the portfolio. In total, the errors and underestimates amount to $7.2 billion relative to the NPV calculation provided in the Alternative Cost of Service Calculation in the Mid Load Forecast.

In addition, the CEC submits that there are substantial risk differences that should be assessed between the Alternative Portfolio and the Site C portfolio.

CEC Assessment of the Alternative Portfolio

Error/Underestimation	Value ($ Billion)
Battery Cost - Error	2.0
Capital Cost Undervalue - Error	2.0
Capacity Difference with Site C – Qualitative Difference	1.0
Surplus Energy and Surplus Capacity Credit – Not Comparable	0.6
Longevity of Site C – Not Evaluated	1 .0
Wind Costs - Underestimated	0.6
Total	$7.2Billion

The CEC provides the following comments with respect to the calculations, inputs, and assumptions contained in the Alternative Portfolio.

ALTERNATIVE PORTFOLIO APPEARS TO CONTAIN $2.0 BILLION ERROR IN BATTERY COSTS

The Alternative Portfolio (Mid Forecast) includes 300 MW from batteries for a period of 10 years commencing in F2025, and an additional 100 MW of capacity for ten years commencing in F2026.

Battery costs are included as a capitalized cost of $542/kW in F2025, and $516/kW in F2026 in the Medium Load Forecast portfolio cost tab, at cells D12 and D13.

Battery costs were estimated using an NREL report 'Exploring the Potential Competitiveness (using the Median line in Figure 18) and a 10-year battery life was assumed.

The CEC provides the following graph from the source cited.

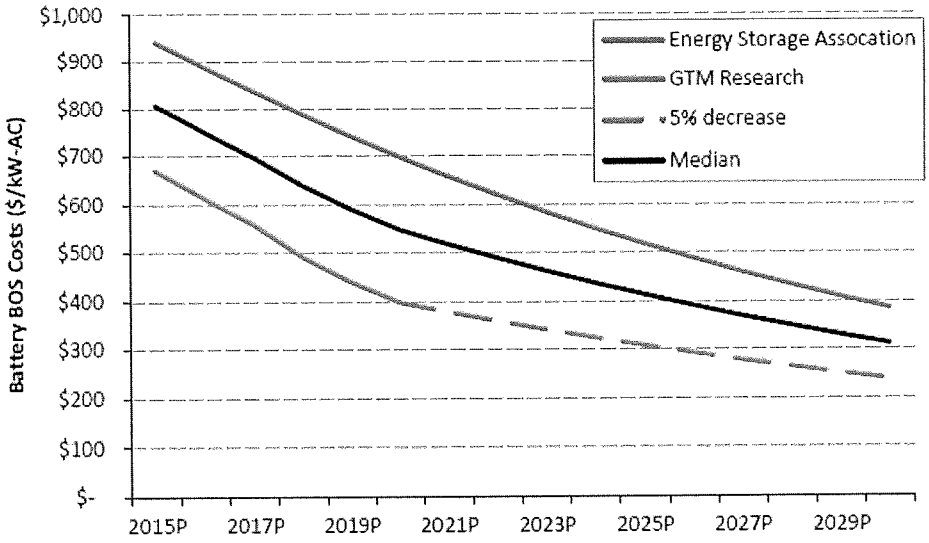


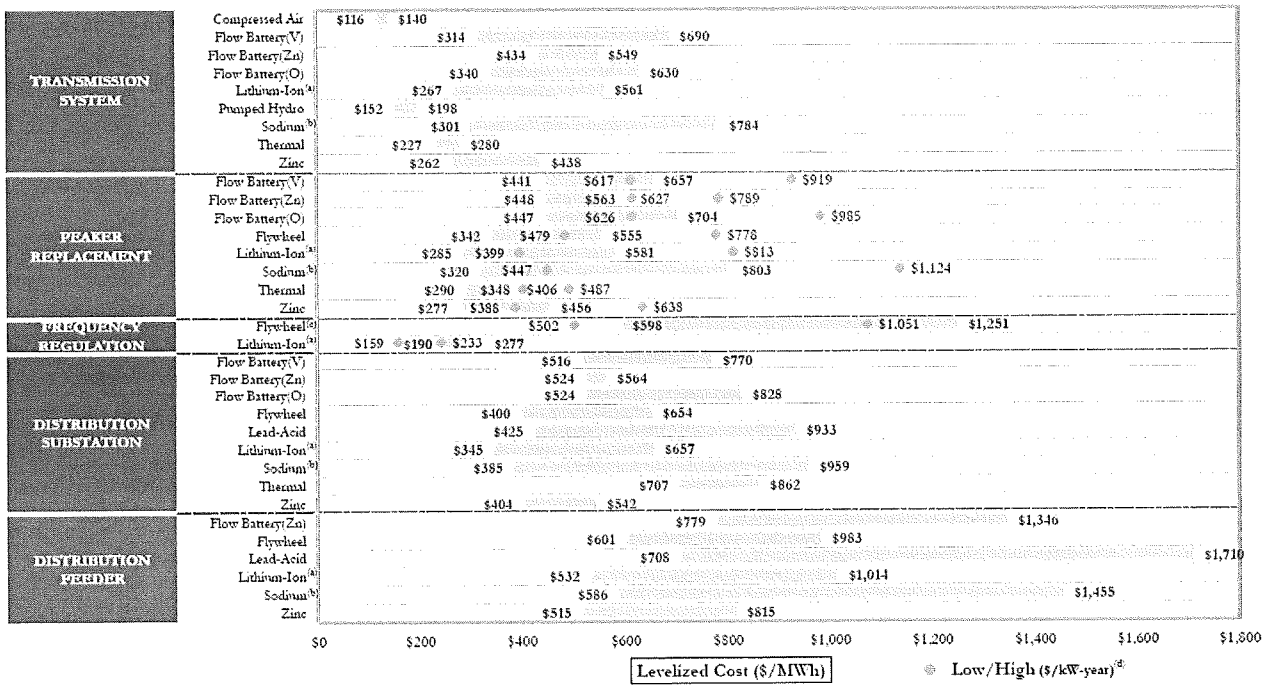
Figure 18. Estimated battery BOS costs, 2015–2030

Sources: GTM Research 2016; Roberts 2015

The CEC points out that the costs cited are for Balance of System (BOS) costs and are recorded in '$/KW-AC'. These do not include the bulk of the costs, including the capital costs of the batteries. -

Lazard's December 2016 'Levelized Cost of Storage Version 2.0' report estimate of Large Scale energy storage systems designed to replace peaking gas turbines and provide capacity and energy, spinning reserves and non-spinning reserves indicate an approximate cost of between $400/kW-year and $813/kW-year. These can be brought online quickly to meet the rapidly increasing demand for power at peak. Results are shown in $/kW-year as well as $/MWh.

Unsubsidized Levelized Cost of Storage Comparison



Source: Lazard and Energistics Partners estimates.

Note: Flow Battery(V) represents Vanadium Flow Batteries; Flow Battery(Zn) represents Zinc-Bromine Flow Batteries; Flow Battery(O) represents Other Flow Batteries. Lazard's LCOS v1.0 study did not separately analyze each of these distinct technologies within Flow Battery.

(a) Lithium-Ion-Power technology used in the Frequency Regulation and Microgrid Use Cases due to low duration/high power requirements. Lithium-Ion-Energy systems are used in all other Use Cases that include Lithium-Ion technology.

(b) Sodium-Low Temperature systems are used in Commercial Appliance and Residential Use Cases. Sodium-High Temperature systems are used in all other Use Cases that utilize Sodium technology.

(c) Flywheel storage in the Frequency Regulation Use Case represents short-duration storage. Flywheel storage in all other Use Cases represents long-duration storage.

(d) Reflects conversion of LCOS figure ($/MWh) by multiplying by total annual energy throughput (MWh) and dividing by capacity (kW).

11

The CEC notes that these cost figures are of a similar $ range to the $516/kW -$ 542/kW recorded in the portfolio costs. These costs are expressed in a $/kW-year, and not the $/KW units recorded in the Commission spreadsheet.

The battery costs in the Alternative Portfolio (mid load) are included as one-time costs of $163 million (F2025) and $52 million (F2026) (Mid Load Forecast).

The CEC has examined the Unsubsidized Levelized Cost of Storage costs as recorded in the Lazard report which have been costed in $/KW-year units rather than in $/KW ..Accordingly, th costs would be included every year over their 10-year life.

The CEC has conservatively calculated the Present Value of the Peaker Replacement batteries. Using the average cost of only the lower priced batteries, (ie. Excluding the higher priced options) and applying a 10% premium the CEC finds the difference between these costs and those recorded in the Alternative Portfolio to be a roughly $2.0 billion under-estimation of the cost of capacity from batteries.

The CEC submits that additionally the cost numbers selected represent the low end of the figures provided by Lazard.

Further, the CEC's analysis supporting the cost numbers selected by the Commission staff for US dollars exchange and inflation indicate that the staff's numbers could be lower than appropriate reference material.

The Commission staff also apparently have nothing in their cost analysis for the energy losses on the turnaround between storage and discharge, expected to be at least 8%.

Finally, the CEC notes that battery technologies tend to decline in performance with the number of charge/discharge cycles over time, and this decline is also apparently not reflected. Generally, battery technology for grid scale energy storage is far less cost-effective than pumped storage or natural gas peaker plants which are the standard for energy utility reliable storage capacity products.

ALTERNATIVE PORTFOLIO UNDERVALUES CAPITAL COSTS BY $2 BILLION

The CEC notes that Alternative Portfolio appears to treat the capital costs included in the NPV calculation as 'Depreciation' in the Medium LF.

The Total Generation Cost of Service (line 295 NPV tab) includes Total Operating costs (line 290) plus Total capital charges (line 285) with adjustments for credits (portfolio costs tab line 38 and NPV tab line 294) which are discounted in the calculation of the NPV (NPV tab, cell I5). Total capital charges (line 285 NPV tab) are the sum of Depreciation (line 282), Return on Equity (line 283) and Interest on Debt (line 284).

The CEC submits that the treatment of capital costs as a Depreciation figure results in the amortized costs being significantly discounted and representing much lower costs than those that would be actually incurred.

The CEC recognizes that the cost treatment may be intended to reflect the rate experience of the ratepayers, if the costs were to be amortized. The CEC submits that this is not a proper reflection of the costs that would occur, and is not the same treatment as that provided in the Site C analysis.

The CEC has calculated the cost difference from this treatment and submits that it is in the order of $2 billion underestimating the present value costs.

ALTERNATIVE PORTFOLIO CAPACITY IS NOT COMPARABLE TO SITE C - $1 BILLION DIFFERENCE

The qualitative difference between the storage and capacity values of Site C and the Alternative Portfolio are primarily driven by intermittency of wind and the human behaviour variability for DSM.

The Wind resource is a substantial part of the Alternative Portfolio and it will require significant resources from BC Hydro's hydroelectric system to be able to deliver energy appropriately and reliably to the loads.

The consequence is that added cost will be incurred by BC Hydro to enable an Alternative Portfolio. These costs will be comparable to future pumped storage costs, such that roughly 1/2 to 2/3rds of the portfolio will require from $100/kW-year to $200/kW-year support.

It should be remembered that to the extent that adding intermittent resources uses up capacity capability in the system BC Hydro's energy trade revenues can be impacted.

The CEC calculates that the additional resources required will cost on the order of $1 billion or more.

To demonstrate the qualitative differences the CEC has examined the key attributes of firmness, shaping and grid reliability below.

Firmness

The Commission staff's assumptions regarding Firming (assumption 18) are that through the inclusion of capacity demand-side options and batteries, the Alternative Portfolio has a similar level of firmness as Site C.

The assumption that the Alternative Portfolio is as capable of providing firm supply to customers as Site C is not valid.

The EIA definition of 'firm power' is power producing capacity, intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.

Firm capacity is the amount of energy producing capacity available for production or transmission which can be relied upon or guaranteed to be available at a given time.

Firm energy is the actual energy guaranteed to be available to serve load.

Site C's firmness of capacity assures 1100 MW of capacity with very high operational availability at all times. This capacity is matched by transmission facilities available at N-1 reliability, again very high operational availability.

Site C's firmness stems from the Williston Reservoir, which as the storage capability to average water inflows over multiple years, giving Site C very high firm supply capability. The flows from the GM Shrum power station can be managed through Site C to provide the same firmness of supply across multiple years.

The DSM Time of Use energy savings will have a more limited firmness in that its availability will be dependent upon voluntary customer responses, which can change over time.

The DSM Program energy will have relatively certain firmness where they are derived from physical enduring changes and perhaps less certain firmness where they are dependent in part on human behaviours.

The wind energy will have relatively certain firmness over a year and longer timeframes, but will have vastly less firmness over weekly, daily and hourly time frames.

DSM capacity firmness will provide its proportional share of certainty for all products required to deliver to customers but will have lesser firmness to the extent it is dependent upon customer response and human behaviour.

Wind capacity is defined as effective load carrying capability but the actual firmness of this capacity will be more limited over shorter timeframes.

Battery capacity will be relatively firm but susceptible to degrading capability over time based on charging and discharging cycles.

In summary, the Site C energy and capacity will be qualitatively more firm and reliable than the Alternative Portfolio, meaning that somewhat more of the Alternative Portfolio resources will be required to match the same firmness level.

Shaping, storage

The Commission staff's assumptions are that the Site C reservoir does not have sufficient storage volumes to provide seasonal shaping of generation. (assumption 19) The Alternative Portfolio also does not provide seasonal shaping of generation.

The assumption that the Site C reservoir does not have sufficient storage volumes to provide seasonal shaping is wrong because Site C's seasonal shaping profile is provided by the Williston Reservoir.

The Alternative Portfolio does not have seasonal shaping for the wind component, but the DSM components will have the seasonal profile of its savings reduction profile. So, there is a distinct difference in quality of the products meaning that the Alternative Portfolio will need compensating shaping capacity from another source enable reliable delivery of the energy.

Also, the Alternative Portfolio does not have daily shaping for the wind component and will require the BC Hydro system to store the energy and subsequently dispatch it from the system to serve load.

Site C will have dispatchable energy delivery capability enabling it to shape to the loads daily. The Alternative Portfolio for the DSM component will have shaping to the load based on its savings reduction profile.

In summary, the Site C shaping capabilities will be greater than that of the Alternative Portfolio.

Grid Reliability

In the Commission staff's Alternative Portfolio it is assumed that the Alternative Portfolio results in similar levels of grid reliability compared to Site C as a result of (i) the inclusion of wind integration costs and (ii) by siting Alternative Portfolio resources at the end-user location (for DSM) or at the Site C location (for wind). (assumption 20) Regarding the provision of ancillary services to support the grid (regulation and frequency response, spinning and supplemental reserves), it is assumed that BC Hydro already has sufficient generation assets capable of providing ancillary services to meet North American Electric Reliability Corporation and the Western Electricity Coordinating Council reliability requirements. The Alternative Portfolio does not build for export into a potential ancillary services market.

The assumption that grid reliability across the range of ancillary services will be similar is incorrect.

The Site C contribution to reliability includes the necessary spinning reserves and supplemental reserves. The design also includes synchronous condense capability giving it flexibility to provide ancillary services power that will be substantially superior to the Alternative Portfolio.

The Alternative Portfolio DSM component will have the potential to be credited with its profile 's proportional ancillary services including reserves. The Alternative Portfolio wind component does not have the full ancillary service capability. Wind integration costs will only cover a subset of the requirement. The evidence for this is that BC Hydro has had to build substantial capacity addition to enable intermittent resource additions to the system; the cost for which far exceeds wind integration costing.

The location of the wind energy production in the Peace region of the province does not imbue the wind energy source with the attributes of the Site C energy.

In summary, other ancillary services listed below will need to be sourced from the BC Hydro system to support the wind energy component of the Alternative Portfolio

Benefits of Storage & Capacity

Grid operations uses and benefits for electricity storage (storage) include what are often referred to as ancillary services.
Ancillary services are those functions performed by electrical generating, transmission, system-control, and distribution system equipment and people to support the basic services of generating capacity, energy supply, and power delivery.
The US Federal Energy Regulatory Commission (FERC 1995) defined ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of

control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."

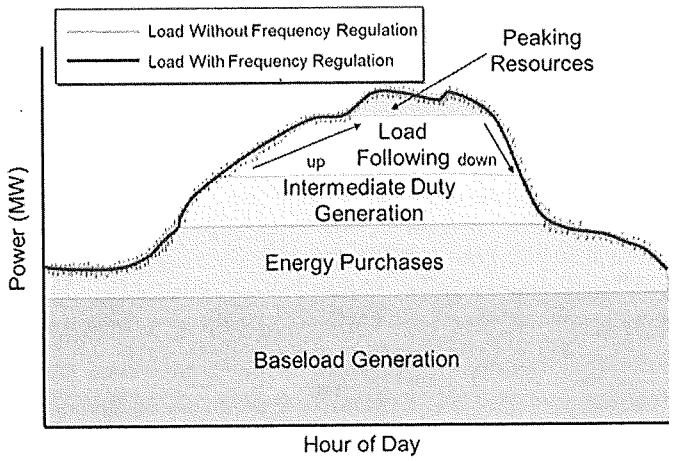
Ancillary Services

Load Following

Load Following is required during the so-called "shoulder hours" during the daily electric demand cycle:

- While electric demand increases in the morning as people get begin their day and get ready for work and school and other normal daily activities, and
- As electric demand diminishes in the evening as work and home activities diminish.

As shown in Figure 1, as electric demand increases, generation output increases to provide load following up and as demand decreases generation output is reduced to provide load following down.



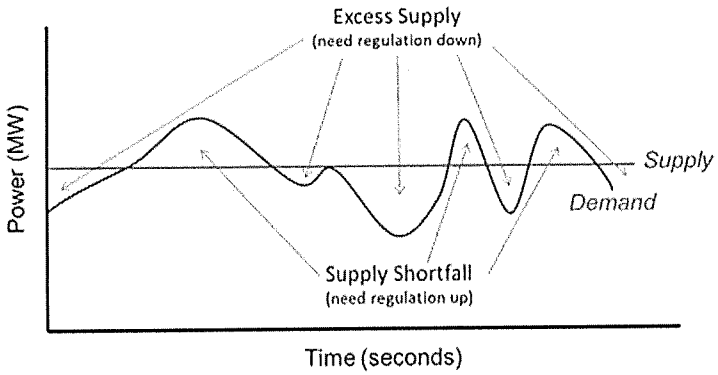
Source: E&I Consulting

Figure 1. "Electric Resources Stack" and hourly system load for one day.

The primary benefit of load following is the reduced need for generation equipment and may reduce generation equipment wear and extend equipment generation life.

Frequency Regulation

Frequency regulation – sometimes referred to as area regulation – is an ancillary service that entails moment-to-moment reconciliation of the difference between electric supply (power) and electric demand. The primary purpose of frequency regulation is to



Source: E&I Consulting

Figure 4. Frequency regulation needs due to momentary differences between demand and a nearly constant supply.

maintain the stability and accuracy of the system-wide alternating current (AC) frequency within a given "control area."

As shown in Figure 4, when supply momentarily exceeds demand (i.e., excess supply) frequency regulation down is needed to offset the discrepancy. Conversely, when supply is momentarily below demand (i.e., supply shortfall) frequency regulation up is needed to offset the discrepancy. As more variable generation resources are added to the electric supply mix, especially wind and solar energy fueled generation, the electric supply will vary along with demand.

Historically, generation has provided most of the area regulation service. Generation provides up or down regulation exclusively, or it can be used to provide some of each.

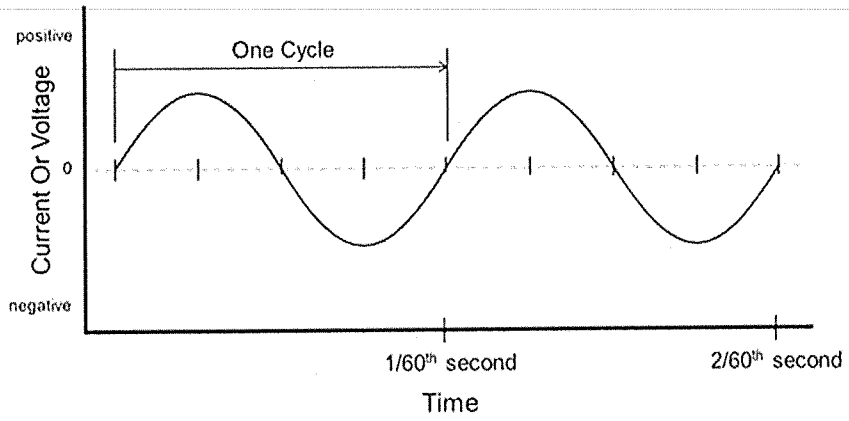
Similar to load following, storage provides area regulation up with increased discharge and/or reduced charging while it provides area regulation down via reduced discharging and/or increased charging. When storage charging is used to provide area regulation, storage related energy losses result in a real-time purchase of make-up energy. So, storage used that way must have high efficiency (i.e., >90%). Storage has important advantages. If the storage used is very efficient (i.e., charging can be used for regulation as well as discharging) then it can provide area regulation equal to two times its power rating. That is because storage can provide both regulation up and regulation down both by charging and by discharging, like load following, but faster.

Fast Frequency Regulation

Storage with a fast ramp rate and that can be configured to have 15 to 30 minutes of storage discharge duration is well-suited to provide area regulation. In fact, there are indications that storage with a high ramp rate is perhaps twice as valuable (i.e., effective) as generation-based area regulation. That is because most types of generation have a slow ramp rate, meaning that their output cannot be changed quickly.

Frequency Response

Storage with a very fast ramp rate can provide the relatively new ancillary service called frequency response. Storage used for frequency response actually monitors the AC frequency and responds to anomalies, over timeframes of milliseconds. The objective is to keep the frequency as close to the



Source: E&I Consulting

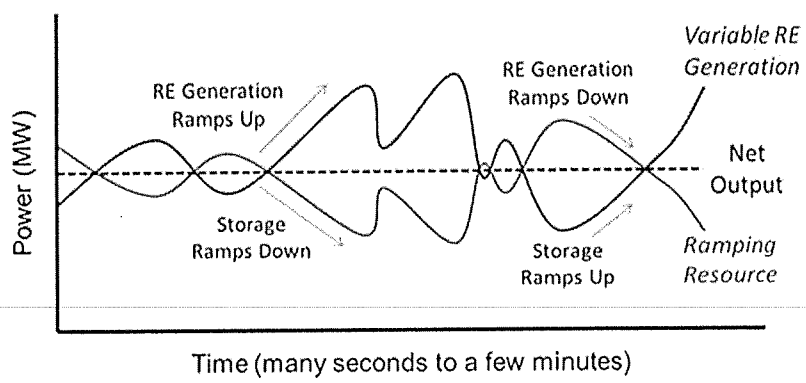
Figure 7. Alternating current (AC) frequency – 60 cycles per second.

target frequency – 60 cycles per second in the United States and Canada – as possible. The concept of frequency and specifically 60 cycles per second AC frequency is shown in Figure 7.
Frequency response is similar to area regulation with an important distinction: Frequency response resources monitor the AC frequency and they respond to frequency excursions whereas area regulation responds indirectly based on control signals that reflect a difference between electric supply (power) electric demand (power). Also, output from frequency response resources changes much faster – in less than a second – than output from area regulation which changes every few seconds or minutes. Currently there are few existing/conventional electric supply resources whose ramp rate is fast enough to respond to sub-second signals so fast storage is especially well-suited to this application.
Storage used for frequency response service should reduce the need for fast-responding generation that would otherwise be needed for area regulation and could reduce generation start-ups, output variability and part load operation which, in turn, reduce fuel use and air emissions.

Ramping

Ramping is a significant change of generation power output over time frames ranging from a few seconds to a few minutes. Of particular interest are: a) wind generation ramping that is caused by rapid wind-speed variations and b) solar generation ramping which occurs as large clouds pass over the generator. Indeed, ramping may increase as variable resources are added to the grid. If ramping does become significant, then system operators will have to respond, or the grid could become unstable.

Similar to load following and area regulation, the ramping ancillary service involves resources that offset output ramping. So, resources used for the ramping service provide output variability that is the reverse of other generations' output variability due to ramping. Perhaps the best example is wind generation whose output ramps up or down quickly as wind speed changes quickly. In that case output from resources providing ramping service must increase or decrease commensurate with wind generation output changes.



Source: E&I Consulting

Figure 8. Variable renewable generation and storage ramping.

The conventional ramping service resource is new and/or existing generation; however, as with area regulation, most generation is not very suitable for ramping because it must be capable of relatively rapid output changes.

For systems needing additional generation capacity, operators might install and operate additional combustion turbines. For grid systems with excess generation capacity, ramping may be accommodated using existing generation whose output can be varied rapidly.
Storage used for ramping service (in lieu of generation) provides ramping up by increasing output and/or by decreasing charging. Conversely, storage provides ramping down by decreasing output and/or increasing charging, as shown in Figure 8.

Reserve Capacity

Reserve capacity is essentially backup generation for the electricity grid, for use if one or two large power sources become unavailable unexpectedly. So, when using storage as electric supply reserve capacity, the need and cost for generation-based reserves is offset and, to a lesser extent, operation cost incurred for generation-based reserve capacity are reduced/avoided.

There are three generic types of reserve capacity:

- Spinning Reserve – Generation capacity that is online but unloaded and that can respond within 10 minutes to compensate for generation or transmission outages. 'Frequency-responsive' spinning reserve responds within 10 seconds to maintain system frequency. Spinning reserves are the first type used when a shortfall occurs. Also known as synchronized reserves.

- Supplemental Reserve – Generation capacity that may be off-line, or that comprises a block of curtailable and/or interruptible loads, and that can be available within 10 minutes. Unlike spinning reserve capacity, supplemental reserve capacity is not synchronized with the grid (frequency). Supplemental reserves are used after all spinning reserves are online.

- Backup Supply – Generation that can pick up load within one hour. Its role is, essentially, a backup for spinning and supplemental reserves. Backup supply may also be used as backup for commercial energy sales.

The amount of reserve capacity needed is driven by electric supply reliability-related standards (typically, 10 to 20% of the normal electric supply capacity).
The benefit from storage used for electric supply reserve capacity is somewhat small because generation-based reserves are inexpensive. Nonetheless, the reserve capacity benefit could be an important element of an attractive storage value proposition because providing reserves using storage has very low incremental cost.

Voltage Support

An important technical challenge for electric grid system operators is to maintain the necessary voltage level and stability. In most cases, meeting that challenge requires management of reactance. To manage reactance at the grid system level, grid system operators rely on an ancillary service called voltage support.
Historically, voltage support has been provided by generation resources that can generate reactive power which offsets reactance in the grid. New technologies (e.g., modular energy storage, modular

generation, power electronics and communications and control systems) make new alternatives for voltage support increasingly viable.
This is an application for which "distributed" storage (storage located close or very close to electricity end-users) may be especially attractive because reactive power cannot be transmitted efficaciously over long distances. Notably, many major power outages are at least partially attributable to problems related to transmitting reactive power to load centers. So, distributed storage – located within the load centers where most reactance occurs – provides especially helpful voltage support.

Black Start

Black start resources are the first to power up to re-energize the grid after a grid-wide outage. Importantly, black start resources must be able to startup without power from the grid and must be able to operate in standby mode, while disconnected from the grid, until they are called upon. In most cases, the black start service is provided by specially-equipped generators. Most storage types are well-suited to serve as black start resources because, unlike generators, they do not need special equipment, and storage does not have to operate while awaiting dispatch.

LONGEVITY OF SITE C NOT VALUED - $1 BILLION

The Alternative Portfolio does not extend to the full 100+ years that Site C is likely to be available to deliver energy. The Site C dam facility which will represent a substantial portion of the Site C costs will have a useful life greater than 100 years. The most likely scenario is for the powerhouse equipment, with a useful life of 70 years, to be refurbished in the same way that wind facilities will be refurbished. A key difference will be that the powerhouse refurbishment will likely be a smaller proportion of costs than the wind refurbishment.

The CEC estimates that this longevity value will create a cost difference between the Alternative Portfolio and the Site C portfolio in the range of 10% of the capital costs of Site C. This value is expected to be in the order of $1 billion, and has been calculated by comparing the Present Value (PV) of the capital investments in each alternative (Site C and Alternative Portfolio) including the differential in the portion of the capital costs needing refurbishment.

WIND COSTS LIKELY UNDERESTIMATED - $600 MILLION

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

Capitalized costs for wind are established at between $263/KW and $297/KW depending on circumstances as shown in the Mid Load Forecast Portfolio cost tab at cells E16 to E29.

Fixed O&M is costed at between $65/KW-y and $66/KW-y (lines E37 – E40) with wind refurbishment and wind (2078 new build) costed at $54/KW-y (lines D45-D48) Additionally, wind integration costs of $2.50/MWh (D52-D56) are added.

The values reflect a Plant Gate cost and the location for wind build has been set to be similar to Site C (Peace Region). (Assumption 5) This was intended to minimize the risk of additional network reinforcements relative to Site C.

BC Hydro's estimate of total Wind Adjusted UEC – Delivery to Lower Mainland is established at $83/MWh before adders and $105/MWh after adders of $22/MWh to reflect the cost to the Lower Mainland, including $5 for wind integration costs[1].

The CEC's estimate of the assumptions embedded in the Alternative Portfolio costs suggest that the total wind costs included in the Alternative Portfolio are in the order of $50/MWh, which is about 47% of Hydro estimate of $105/MWh.

The CEC submits that even assuming a reduction of 45% from BC Hydro's estimate of the base UEC (before adders) the Commission staff have apparently excluded many other costs that should otherwise be included in the wind costs. The CEC finds these to amount to about $18/MWh.

The CEC notes that BC Hydro's Unit Energy Cost for Site C of $43/MWh includes an Adjustment for Delivery to Lower Mainland and annual shape adjustment of +$10/MWh[2] which should not be excluded from the Alternative Portfolio analysis.

The CEC submits that low costs for wind energy are speculative and may not reflect the costs at which the Independent Power Producers (or BC Hydro) would be able to produce and sell electricity.

The CEC estimates the value of this cost differential to be in the order of $600 million.

-Wind Integration

The Alternative Portfolio assumes the integration of wind at cost of $2.5/MWh, which is half of that assumed by BC Hydro ($5/MWh) based on concerns raised in the F18-3 submission, (pp. 14- 17).

The CEABC submission (F18-3) states at page 16:

> Power Advisory studied wind integration costs across many jurisdictions and they are generally estimated to be below $6/MWh and can be as low as $0.50 to $2/MWh even at wind capacity penetration levels beyond 40%, with solar integration costs being lower. This review of variable output renewable energy integration costs indicates that BC Hydro's estimates are considerably higher than most estimates.

[1] A-13, Preliminary Report page 88
[2] A-13, Preliminary Report page 79

In the report submitted by the Clean Energy Association of BC and the Canadian Wind Energy Association Power Advisory LLC states:

> Given the factors influencing wind integration costs...a case can be made that integration costs are more likely to align within a region or market.[3]

The following table is provided.

Table 5: Survey of Recent WECC Renewables Integration Costs

Jurisdiction	Integration Cost ($/MWh)	Year $*	Penetration Level (Capacity Basis)	Notes
Wind				
Arizona Public Service (APS)	3.25 / 4.08	2010	6% (468 MW) / 15% (1,185 MW)	As of the 2017 IRP, APS continues to base integration costs on its 2007 Wind Integration Cost Impact Study. Cost said to be updated "to increased penetration levels of wind in the APS systems and current fuel prices", but the specific value is not provided in the IRP.
PacifiCorp	0.57	2016	30% (3,007 MW)	2017 Flexible Reserve Study (FRS) conducted as part of the 2017 PacifiCorp IRP. Down from $3.06/MWh in the 2014 Wind Integration Study.
Pacific Gas and Electric (PG&E)	4.00	2014	Benchmark Average	Interim variable integration cost for wind approved by the California Public Utilities Commission in the 2014 RPS and IRP off-year proceeding.
Public Service Company of Colorado (PSCo) [Xcel Energy]	2.93	2016	28% (2,000 MW)	2016 ERP. Value based on 2011 Wind Integration Study methodology and updated natural gas prices. PSCo did not allow for gas prices below $3.24/MMBtu, while recognizing current and forecasted gas prices below this value. Average wind integration costs from 2011 were $3.68/MWh for 2 GW of wind.

The CEC considers that the above information does not support wind integration costs of $2.50/MWh, particularly when BC Hydro has declared the costs in BC to be in the order of $5.00/MWh. The CEC considers that the PacifiCorp figure is atypical given the costs in other jurisdictions and should not be used to artificially lower the expected integration costs.

The CEC submits that it is not appropriate to disregard the BC Hydro evidence as to the likely costs that will be experienced with integration.

The CEC submits that BC Hydro will have BC specific costs actual costs that can be examined to assess future wind integration costs.

The CEC recommends that the Commission utilize the BC Hydro costs of $5/MWh unless BC Hydro actuals support a different figure.

The CEC calculates the impact of Wind Integration costs to be double that provided for in the Alternative Portfolio, with an NPV of approximately $80 million more than is included in the Alternative Portfolio.

[3] Page 14

ALTERNATIVE PORTFOLIO POWER EXPORT and SURPLUS CREDITS NOT COMPARABLE - $600 MILLION

Although Site C is not being built for the export market, the CEC submits that the export market provides significant mitigation for the risk of load uncertainty and oversupply. As such, sales to the export market represent an important consideration in an assessment of Site C and the Portfolio Alternative.

The CEC considers that there is a significant qualitative difference in the ability of the Alternative Portfolio to monetize the value of the export and trading market versus that of Site C. The CEC estimates the difference to be in the order of $600 million.

Power and capacity surpluses are costed/priced in Alternative Portfolio as described below. The CEC notes that the Alternative Portfolio treats surplus energy and surplus capacity differently depending on whether or not it exceeds that required by BC Hydro, or whether it exceeds that provided by Site C.

Energy surplus to BC Hydro need (assumption 6)

In any year, if the energy of the Alternative Portfolio exceeds that of the gap to fill, and to the extent that it is surplus to BC Hydro's requirements, the energy is assumed to be exported at a plant gate export price of 2018 $25/MWh. This is based on:

- a forward market F2025 price of Mid-C power of US 30/MWh;
- translated to CAD $ at an exchange rate of 1 CAD $ = USD 0.7979 (CAD $37.60)
- less losses (1.9%) and wheeling costs ($6.3/MWh) to the US/Canada border (CAD $30.59);
- less 11% incremental transmission losses to Site C plant gate location (CAD $27.22);
- adjusted down to CAD $25 to reflect (i) risk premiums inherent in forward market prices; (ii) risk of limited available transmission capacity reducing BC Hydro's ability to access the Mid-C market, and (iii) risk of future downward pressure on Mid-C prices from renewables (such as solar, wind) with low or no incremental generation costs.

Capacity surplus to BC Hydro need (assumption 7)

In any year, if the capacity of the Alternative Portfolio exceeds that of the gap to fill, and to the extent that it is surplus to BC Hydro's requirements, the (Alternative Portfolio) surplus capacity is assumed to have no additional value to BC Hydro (i.e., an export price of CAD $0/kW-year).

Energy Exceeding Site C (assumption 8)

In any year, if the energy of the Alternative Portfolio exceeds that of the gap to fill and is used to meet BC Hydro's domestic load requirements, the cost of the Alternative Portfolio will be reduced proportionally. For example, if the Alternative Portfolio generates 5,564 GWh compared to a gap to fill of 5,286 GWh, only 95% of the cost of the Alternative Portfolio for that year will be included in NPV of the Alternative Portfolio

Capacity Exceeding Site C (assumption 9)

> In any year, if the capacity of the Alternative Portfolio exceeds that of the gap to fill and is used to meet BC Hydro's domestic load requirements, the Alternative Portfolio will be credited with the assumed value of this additional capacity of $50/kW-year. This is referred to as capacity credit in the analysis.

The CEC does not contest the assumptions used for excees energy and capacity of the Alternative Portfolio. However, the CEC notes that similar excesses for Site C are given no credit. The CEC views this as an error in comparable treatment. The CEC has calculated the volume of energy and capacity for Site C in excess of need and applied a value of energy $15/MWh higher than that used by the Alternative Portfolio because of Site C's capacity to generate premium prices.

The evidence presented in the Technical Presentations (October 14th) is that Site C is a highly flexible resource that can be relied on to provide clean, flexible capacity and energy to Powerex's external customers.[4] BC Hydro anticipates rapid change in external markets and a potential capacity void. Customer options for clean, flexible capacity are limited.

Because of the dispatchability BC Hydro will largely be able to choose the hours in which they sell surplus. It is anticipated that Powerex will be able to sell energy in the higher priced hours of the year, and to purchase energy in the lower priced hours. Additionally, Powerex will be able to sell explicit capacity and flexibility products, which earn premiums in addition to any energy delivery.

The CEC submits that it would be appropriate for the Commission to ensure that it has the appropriate evidence available to assess the differences in the capacity values of Site C and that of wind and DSM.

The CEC has estimated the difference in the ability of the Alternative Portfolio and the Site C option as being in the order of $600 million.

UNCERTAINTIES AND RISKS

The risk profile for Site C and for the Alternative Portfolio are quite different.

The Alternative Portfolio has substantial risks as described below.

1. There is a technological risk as to whether or not the full extent of the cost reductions will be deliverable. The Alternative Profile has calculated in one of the deepest cost reduction expectations of the range of forecasts. There is at least a significant risk that its cost efficiency may not be what is in the profile.
2. There is a technical risk that DSM capacity programs will be a flat profile capacity reduction and not a dispatchable one, such as might be obtained through utility controlled demand response on customer equipment.

[4] Transcript October 14, 2017 Testimony of Mr. Bechard

3. There is a technical risk that battery technology will not meet the requirements defined for it in the Alternative Portfolio, particularly given that it is emerging technology.

Site C's technical risk are very different revolving around geotechnical issues, now substantially understood and around workforce efficiency as well as contract supply not yet let.

Site C is being reviewed in a context of potential overrun cost and the Alternative Portfolio does not have the same rigour of costing n the estimates, having the costs sourced from generic studies. Consequently, there is a risk in balance between the two options built into the analysis.

The CEC finds that the risks in the Alternative Portfolio have greater variability and potential consequences to produce more costly results than completing Site C.

The CEC recommends that the Panel advise government that exploration of an Alternative Portfolio need considerably more time and expert systems planning analysis than has been available in the Inquiry period.

The CEC recommends that the Panel advise the government that it weigh heavily the risk to the costs of the Alternative Portfolio.

CEC CONCLUSIONS

The Panel has been asked to provide an Alternative Portfolio to Site C and has assembled what is was able to ascertain from various components of submissions and evidence available in this process.

The CEC submits that the quality of this evidence and the Alternative Portfolio analysis done to date are not very strong, particularly given the nature of errors contained therein.

There is clearly difficulty in creating a spreadsheet model of complex attributes which are integrated in BC Hydro's portfolio modelling and accounting for the electrical system planning issues not modelled or evident at the level the Panel is able to conduct this inquiry.

The Panel is not composed of electrical system planning experts and the evidence in the Alternative Portfolio does not meet prudency levels for system planning. Nevertheless, the Alternative Portfolio and others could have significant benefits in planning for cost-effective supply and are likely options for a future where load growth is driven by policy on electrification.

The CEC recommends that the Panel offer the government the advice that system planning work continues on Alternative Portfolio options but that the evidence is not sufficiently solid that the Panel could offer a firm conclusion as to its benefits at this time.

The CEC submits that the ratepayer impact of cancelling Site C is so substantial that it likely overwhelms the potential benefits of an Alternative Portfolio with such significant uncertainty as to its costs.

The CEC submits that it is important to recognize the overarching evidence that resources such as Site C are Heritage System quality assets with low costs for energy and capacity, particularly given the current sunk and termination costs, as well as ratepayer opportunity costs expected by the CEC to total more than $5 billion.

Site C also provides the opportunity to mitigate the risk of surplus through the export market. To the extent that the future provides significant load uncertainty on the upside through electrification, it remains possible that if Site C is not completed then more expensive versions of similar resources could be required.

Commercial Energy Consumers Association of BC (CEC)

Comments on the Alternative Portfolio

INTRODUCTION

In Exhibit A-22, the BC Utilities Commission (BCUC or Commission) invites comments regarding three Illustrative Alternative Portfolios developed by Commission staff to replace Site C energy and capacity. The illustrative Alternative Portfolios are designed to replace only Site C energy and capacity used for domestic consumption, and do not include generation built for the purpose of export.

The Commission notes explicitly that the illustrated Alternative Portfolios are provided for the purposes of soliciting feedback only. No findings have been made by the Panel regarding the assumptions used in the model or the general approach used.

CEC SUMMARY COMMENTS

The CEC agrees that it is highly appropriate for the Panel to avoid making the findings with regard to the appropriateness of the Alternative Portfolios at this time given the lack of information and understanding regarding the fundamentals of energy and capacity planning. However, the CEC submits that the development of the Alternative Portfolio represents an important step in the assessment of Site C and could be further examined with additional evidence and costing information to ensure the validity of the information.

The CEC recommends, that when advising the government, the Panel provide cautionary notes as to the value of the Alternative Portfolios until further analysis can be completed by system planning experts

The Panel invites comments from BC Hydro and other parties on these Alternative Portfolios of generating projects and demand-side management (DSM) initiatives; in particular:

- The underlying assumptions regarding the Alternative Portfolios; and
- The calculations, inputs and assumptions used in the Alternative Portfolio Spreadsheet.

The CEC is concerned with several of the assumptions and calculations that the Commission staff employed in their development and analysis of the Alternative Portfolio.

The CEC finds that the Commission Staff calculation of the net present value of the Alternative Portfolio at $2.889 billion contains significant error and grossly underestimates the cost of the portfolio. In total, the errors and underestimates amount to $~~6.7~~7.2 billion relative to the NPV calculation provided in the Alternative Cost of Service Calculation in the Mid Load Forecast.

In addition, the CEC submits that there are substantial risk differences that should be assessed between the Alternative Portfolio and the Site C portfolio.

CEC Assessment of the Alternative Portfolio

Error/Underestimation	Value ($ Billion)
Battery Cost - Error	~~1.5~~2.0
Capital Cost Undervalue - Error	2.0
Capacity Difference with Site C – Qualitative Difference	1.0
Surplus Energy and Surplus Capacity Credit – Not Comparable	0.6
Longevity of Site C – Not Evaluated	1 .0
Wind Costs - Underestimated	0.6
Total	$7.2~~6.7~~ Billion

The CEC provides the following comments with respect to the calculations, inputs, and assumptions contained in the Alternative Portfolio.

ALTERNATIVE PORTFOLIO APPEARS TO CONTAIN $~~1.5~~2.0 BILLION ERROR IN BATTERY COSTS

The Alternative Portfolio (Mid Forecast) includes 300 MW from batteries for a period of 10 years commencing in F2025, and an additional 100 MW of capacity for ten years commencing in F2026.

Battery costs are included as a capitalized cost of $542/kW in F2025, and $516/kW in F2026 in the Medium Load Forecast portfolio cost tab, at cells D12 and D13.

Battery costs were estimated using an NREL report 'Exploring the Potential Competitiveness (using the Median line in Figure 18) and a 10-year battery life was assumed.

The CEC provides the following graph from the source cited.

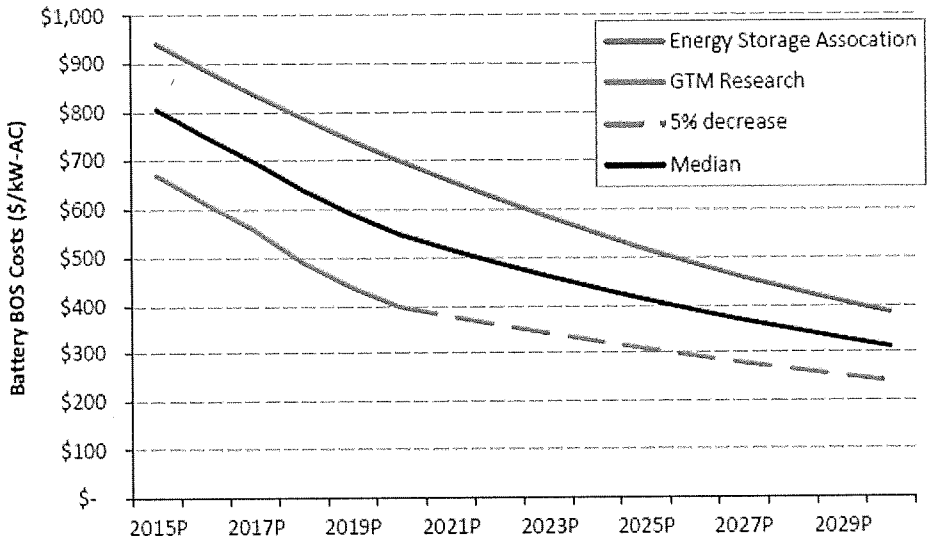


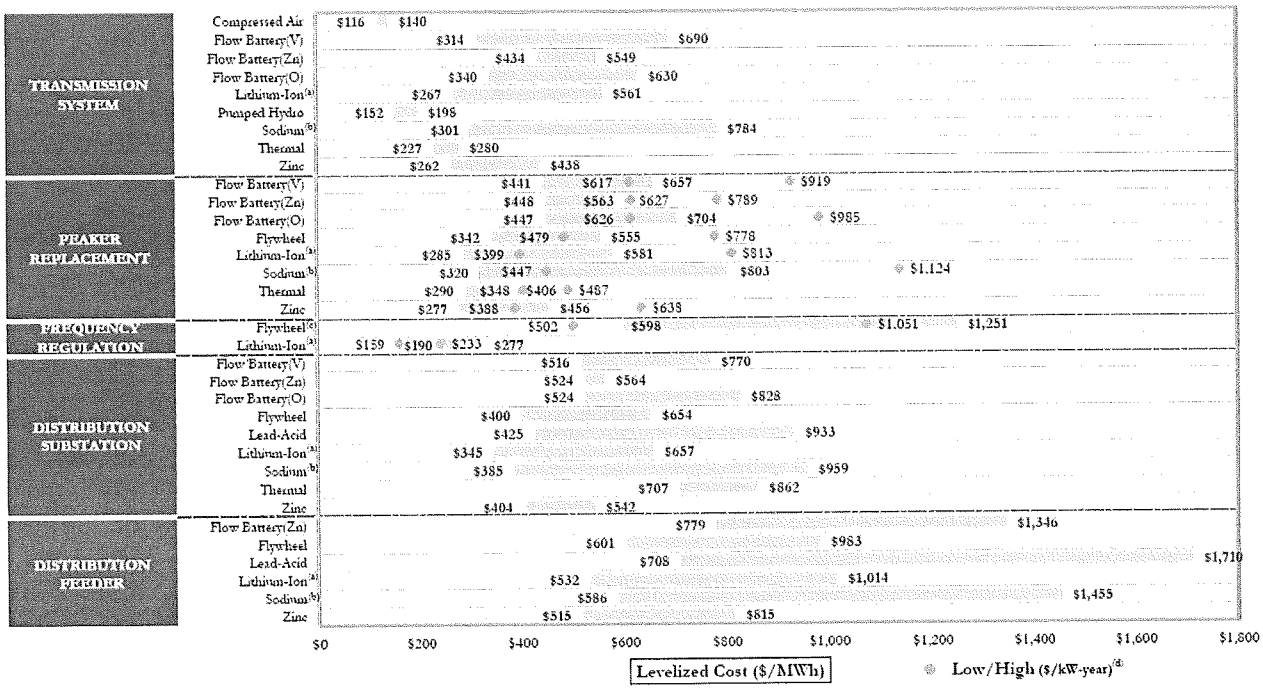
Figure 18. Estimated battery BOS costs, 2015–2030

Sources: GTM Research 2016; Roberts 2015

The CEC points out that the costs cited are for Balance of System (BOS) costs and are recorded in '$/KW-AC'. These do not include the bulk of the costs, including the capital costs of the batteries. ~~which represent Annual Costs.~~

Lazard's December 2016 'Levelized Cost of Storage Version 2.0' report estimate of Large Scale energy storage systems designed to replace peaking gas turbines and provide capacity and energy, spinning reserves and non-spinning reserves indicate an approximate cost of between $400/kW-year and $813/kW-year. These can be brought online quickly to meet the rapidly increasing demand for power at peak. Results are shown in $/kW-year as well as $/MWh.

Unsubsidized Levelized Cost of Storage Comparison



Source: Lazard and Innovation Partners estimates.

Note: Flow Battery(V) represents Vanadium Flow Batteries; Flow Battery(Zn) represents Zinc-Bromine Flow Batteries; Flow Battery(O) represents Other Flow Batteries. Lazard's LCOS v1.0 study did not separately analyze each of these distinct technologies within Flow Battery.

(a) Lithium-Ion-Power technology used in the Frequency Regulation and Microgrid Use Cases due to low duration/high power requirements. Lithium-Ion-Energy systems are used in all other Use Cases that include Lithium-Ion technology.

(b) Sodium-Low Temperature systems are used in Commercial Appliance and Residential Use Cases. Sodium-High Temperature systems are used in all other Use Cases that utilize Sodium technology.

(c) Flywheel storage in the Frequency Regulation Use Case represents short-duration storage. Flywheel storage in all other Use Cases represents long-duration storage.

(d) Reflects conversion of LCOS figure ($/MWh) by multiplying by total annual energy throughput (MWh) and dividing by capacity (kW).

11

The CEC notes that these cost figures are of a similar $ range to the $516/kW -$ 542/kW recorded in the portfolio costs~~, however these~~. These costs are expressed in a $/kW-year, ~~instead of~~and not the $/KW units recorded in the Commission spreadsheet.

The battery costs in the Alternative Portfolio (mid load) are included as one-time costs of $163 million (F2025) and $52 million (F2026) (Mid Load Forecast).

The CEC has examined the ~~submits that battery~~ Unsubsidized Levelized Cost of Storage costs as recorded in the Lazard report which have ~~should have~~ been costed in $/KW-year units rather than in $/KW~~,~~ ..~~and accordingly~~ Accordingly, the costs ~~should~~ would be included every year over their 10-year life.

The CEC has conservatively calculated the Present Value of the Peaker Replacement batteries. Using the average cost of only the lower priced batteries, (ie. Excluding the higher priced options) and applying a 10% premium ~~such an error and submits that this difference~~the CEC finds the difference between these costs and those recorded in the Alternative Portfolio ~~results in~~to be -a roughly $~~1.5~~2.0 billion under-estimation of the cost of capacity from batteries.

The CEC submits that additionally the cost numbers selected represent the low end of the figures provided by Lazard.

Further, the CEC's analysis supporting the cost numbers selected by the Commission staff for US dollars exchange and inflation indicate that the staff's numbers could be lower than appropriate reference material.

The Commission staff also apparently have nothing in their cost analysis for the energy losses on the turnaround between storage and discharge, expected to be at least 8%.

Finally, the CEC notes that battery technologies tend to decline in performance with the number of charge/discharge cycles over time, and this decline is also apparently not reflected. Generally, battery technology for grid scale energy storage is far less cost-effective than pumped storage or natural gas peaker plants which are the standard for energy utility reliable storage capacity products.

ALTERNATIVE PORTFOLIO UNDERVALUES CAPITAL COSTS BY $2 BILLION

The CEC notes that Alternative Portfolio appears to treat the capital costs included in the NPV calculation as 'Depreciation' in the Medium LF.

The Total Generation Cost of Service (line 295 NPV tab) includes Total Operating costs (line 290) plus Total capital charges (line 285) with adjustments for credits (portfolio costs tab line 38 and NPV tab line 294) which are discounted in the calculation of the NPV (NPV tab, cell I5). Total capital charges (line 285 NPV tab) are the sum of Depreciation (line 282), Return on Equity (line 283) and Interest on Debt (line 284).

The CEC submits that the treatment of capital costs as a Depreciation figure results in the amortized costs being significantly discounted and representing much lower costs than those that would be actually incurred.

The CEC recognizes that the cost treatment may be intended to reflect the rate experience of the ratepayers, if the costs were to be amortized. The CEC submits that this is not a proper reflection of the costs that would occur, and is not the same treatment as that provided in the Site C analysis.

The CEC has calculated the cost difference from this treatment and submits that it is in the order of $2 billion underestimating the present value costs.

ALTERNATIVE PORTFOLIO CAPACITY IS NOT COMPARABLE TO SITE C - $1 BILLION DIFFERENCE

The qualitative difference between the storage and capacity values of Site C and the Alternative Portfolio are primarily driven by intermittency of wind and the human behaviour variability for DSM. The Wind resource is a substantial part of the Alternative Portfolio and it will require significant resources from BC Hydro's hydroelectric system to be able to deliver energy appropriately and reliably to the loads.

The consequence is that added cost will be incurred by BC Hydro to enable an Alternative Portfolio. These costs will be comparable to future pumped storage costs, such that roughly 1/2 to 2/3rds of the portfolio will require from $100/kW-year to $200/kW-year support.

It should be remembered that to the extent that adding intermittent resources uses up capacity capability in the system BC Hydro's energy trade revenues can be impacted.

The CEC calculates that the additional resources required will cost on the order of $1 billion or more.

To demonstrate the qualitative differences the CEC has examined the key attributes of firmness, shaping and grid reliability below.

Firmness

The Commission staff's assumptions regarding Firming (assumption 18) are that through the inclusion of capacity demand-side options and batteries, the Alternative Portfolio has a similar level of firmness as Site C.

The assumption that the Alternative Portfolio is as capable of providing firm supply to customers as Site C is not valid.

The EIA definition of 'firm power' is power producing capacity, intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.

Firm capacity is the amount of energy producing capacity available for production or transmission which can be relied upon or guaranteed to be available at a given time.

Firm energy is the actual energy guaranteed to be available to serve load.

Site C's firmness of capacity assures 1100 MW of capacity with very high operational availability at all times. This capacity is matched by transmission facilities available at N-1 reliability, again very high operational availability.

Site C's firmness stems from the Williston Reservoir, which as the storage capability to average water inflows over multiple years, giving Site C very high firm supply capability. The flows from the GM Shrum power station can be managed through Site C to provide the same firmness of supply across multiple years.

The DSM Time of Use energy savings will have a more limited firmness in that its availability will be dependent upon voluntary customer responses, which can change over time.

The DSM Program energy will have relatively certain firmness where they are derived from physical enduring changes and perhaps less certain firmness where they are dependent in part on human behaviours.

The wind energy will have relatively certain firmness over a year and longer timeframes, but will have vastly less firmness over weekly, daily and hourly time frames.

DSM capacity firmness will provide its proportional share of certainty for all products required to deliver to customers but will have lesser firmness to the extent it is dependent upon customer response and human behaviour.

Wind capacity is defined as effective load carrying capability but the actual firmness of this capacity will be more limited over shorter timeframes.

Battery capacity will be relatively firm but susceptible to degrading capability over time based on charging and discharging cycles.

In summary, the Site C energy and capacity will be qualitatively more firm and reliable than the Alternative Portfolio, meaning that somewhat more of the Alternative Portfolio resources will be required to match the same firmness level.

Shaping, storage

The Commission staff's assumptions are that the Site C reservoir does not have sufficient storage volumes to provide seasonal shaping of generation. (assumption 19) The Alternative Portfolio also does not provide seasonal shaping of generation.

The assumption that the Site C reservoir does not have sufficient storage volumes to provide seasonal shaping is wrong because Site C's seasonal shaping profile is provided by the Williston Reservoir.

The Alternative Portfolio does not have seasonal shaping for the wind component, but the DSM components will have the seasonal profile of its savings reduction profile. So, there is a distinct difference in quality of the products meaning that the Alternative Portfolio will need compensating shaping capacity from another source enable reliable delivery of the energy.

Also, the Alternative Portfolio does not have daily shaping for the wind component and will require the BC Hydro system to store the energy and subsequently dispatch it from the system to serve load.

Site C will have dispatchable energy delivery capability enabling it to shape to the loads daily. The Alternative Portfolio for the DSM component will have shaping to the load based on its savings reduction profile.

In summary, the Site C shaping capabilities will be greater than that of the Alternative Portfolio.

Grid Reliability

In the Commission staff's Alternative Portfolio it is assumed that the Alternative Portfolio results in similar levels of grid reliability compared to Site C as a result of (i) the inclusion of wind integration costs and (ii) by siting Alternative Portfolio resources at the end-user location (for DSM) or at the Site C location (for wind). (assumption 20) Regarding the provision of ancillary services to support the grid (regulation and frequency response, spinning and supplemental reserves), it is assumed that BC Hydro already has sufficient generation assets capable of providing ancillary services to meet North American Electric Reliability Corporation and the Western Electricity Coordinating Council reliability requirements. The Alternative Portfolio does not build for export into a potential ancillary services market.

The assumption that grid reliability across the range of ancillary services will be similar is incorrect.

The Site C contribution to reliability includes the necessary spinning reserves and supplemental reserves. The design also includes synchronous condense capability giving it flexibility to provide ancillary services power that will be substantially superior to the Alternative Portfolio.

The Alternative Portfolio DSM component will have the potential to be credited with its profile 's proportional ancillary services including reserves. The Alternative Portfolio wind component does not have the full ancillary service capability. Wind integration costs will only cover a subset of the requirement. The evidence for this is that BC Hydro has had to build substantial capacity addition to enable intermittent resource additions to the system; the cost for which far exceeds wind integration costing.

The location of the wind energy production in the Peace region of the province does not imbue the wind energy source with the attributes of the Site C energy.

In summary, other ancillary services listed below will need to be sourced from the BC Hydro system to support the wind energy component of the Alternative Portfolio

Benefits of Storage & Capacity

Grid operations uses and benefits for electricity storage (storage) include what are often referred to as ancillary services.
Ancillary services are those functions performed by electrical generating, transmission, system-control, and distribution system equipment and people to support the basic services of generating capacity, energy supply, and power delivery.

The US Federal Energy Regulatory Commission (FERC 1995) defined ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."

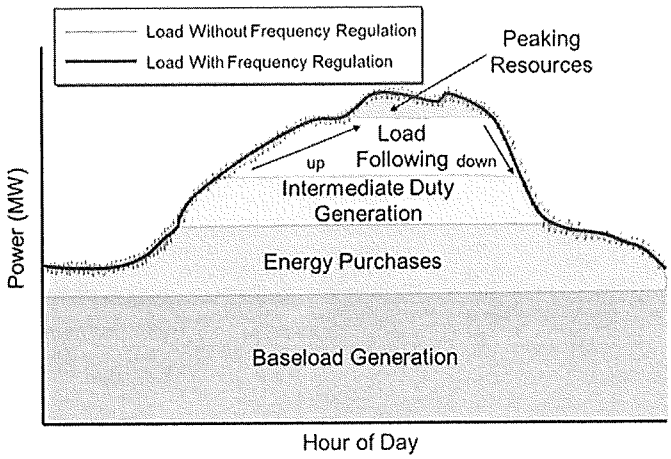
Ancillary Services

Load Following

Load Following is required during the so-called "shoulder hours" during the daily electric demand cycle:

- While electric demand increases in the morning as people get begin their day and get ready for work and school and other normal daily activities, and
- As electric demand diminishes in the evening as work and home activities diminish.

As shown in Figure 1, as electric demand increases, generation output increases to provide load following up and as demand decreases generation output is reduced to provide load following down.



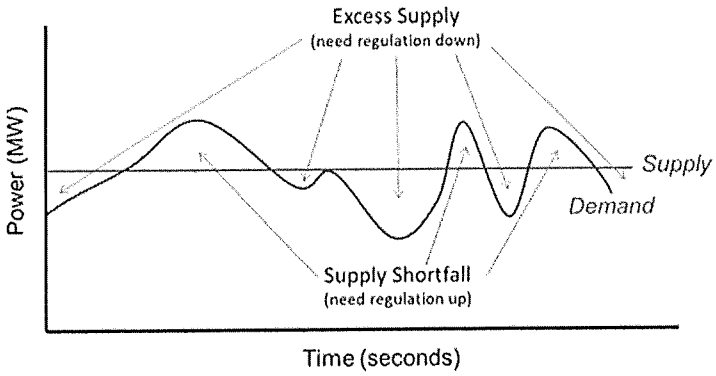
Source: E&I Consulting

Figure 1. "Electric Resources Stack" and hourly system load for one day.

The primary benefit of load following is the reduced need for generation equipment and may reduce generation equipment wear and extend equipment generation life.

Frequency Regulation

Frequency regulation – sometimes referred to as area regulation – is an ancillary service that entails moment-to-moment reconciliation of the difference between electric supply (power) and electric demand. The



Source: E&I Consulting

Figure 4. Frequency regulation needs due to momentary differences between demand and a nearly constant supply.

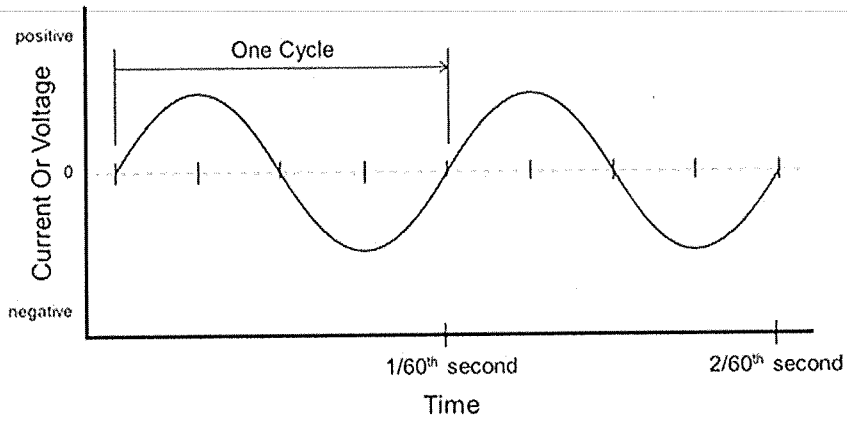
primary purpose of frequency regulation is to maintain the stability and accuracy of the system-wide alternating current (AC) frequency within a given "control area."
As shown in Figure 4, when supply momentarily exceeds demand (i.e., excess supply) frequency regulation down is needed to offset the discrepancy. Conversely, when supply is momentarily below demand (i.e., supply shortfall) frequency regulation up is needed to offset the discrepancy. As more variable generation resources are added to the electric supply mix, especially wind and solar energy fueled generation, the electric supply will vary along with
demand.
Historically, generation has provided most of the area regulation service. Generation provides up or down regulation exclusively, or it can be used to provide some of each.
Similar to load following, storage provides area regulation up with increased discharge and/or reduced charging while it provides area regulation down via reduced discharging and/or increased charging. When storage charging is used to provide area regulation, storage related energy losses result in a real-time purchase of make-up energy. So, storage used that way must have high efficiency (i.e., >90%). Storage has important advantages. If the storage used is very efficient (i.e., charging can be used for regulation as well as discharging) then it can provide area regulation equal to two times its power rating. That is because storage can provide both regulation up and regulation down both by charging and by discharging, like load following, but faster.

Fast Frequency Regulation

Storage with a fast ramp rate and that can be configured to have 15 to 30 minutes of storage discharge duration is well-suited to provide area regulation. In fact, there are indications that storage with a high ramp rate is perhaps twice as valuable (i.e., effective) as generation-based area regulation. That is because most types of generation have a slow ramp rate, meaning that their output cannot be changed quickly.

Frequency Response

Storage with a very fast ramp rate can provide the relatively new ancillary service called frequency response. Storage used for frequency response actually monitors the AC frequency and responds to anomalies, over timeframes of milliseconds. The objective is to keep the frequency as close to the



Source: E&I Consulting

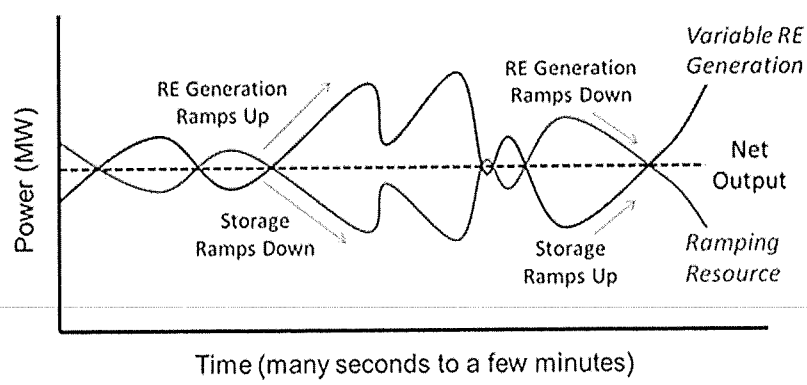
Figure 7. Alternating current (AC) frequency – 60 cycles per second.

target frequency – 60 cycles per second in the United States and Canada – as possible. The concept of frequency and specifically 60 cycles per second AC frequency is shown in Figure 7.
Frequency response is similar to area regulation with an important distinction: Frequency response resources monitor the AC frequency and they respond to frequency excursions whereas area regulation responds indirectly based on control signals that reflect a difference between electric supply (power) electric demand (power). Also, output from frequency response resources changes much faster – in less than a second – than output from area regulation which changes every few seconds or minutes. Currently there are few existing/conventional electric supply resources whose ramp rate is fast enough to respond to sub-second signals so fast storage is especially well-suited to this application.
Storage used for frequency response service should reduce the need for fast-responding generation that would otherwise be needed for area regulation and could reduce generation start-ups, output variability and part load operation which, in turn, reduce fuel use and air emissions.

Ramping

Ramping is a significant change of generation power output over time frames ranging from a few seconds to a few minutes. Of particular interest are: a) wind generation ramping that is caused by rapid wind-speed variations and b) solar generation ramping which occurs as large clouds pass over the generator. Indeed, ramping may increase as variable resources are added to the grid. If ramping does become significant, then system operators will have to respond, or the grid could become unstable.

Similar to load following and area regulation, the ramping ancillary service involves resources that offset output ramping. So, resources used for the ramping service provide output variability that is the reverse of other generations' output variability due to ramping. Perhaps the best example is wind generation whose output ramps up or down quickly as wind speed changes quickly. In that case output from resources providing ramping service must increase or decrease commensurate with wind generation output changes.



Source: E&I Consulting

Figure 8. Variable renewable generation and storage ramping.

The conventional ramping service resource is new and/or existing generation; however, as with area regulation, most generation is not very suitable for ramping because it must be capable of relatively rapid output changes.

For systems needing additional generation capacity, operators might install and operate additional combustion turbines. For grid systems with excess generation capacity, ramping may be accommodated using existing generation whose output can be varied rapidly.
Storage used for ramping service (in lieu of generation) provides ramping up by increasing output and/or by decreasing charging. Conversely, storage provides ramping down by decreasing output and/or increasing charging, as shown in Figure 8.

Reserve Capacity

Reserve capacity is essentially backup generation for the electricity grid, for use if one or two large power sources become unavailable unexpectedly. So, when using storage as electric supply reserve capacity, the need and cost for generation-based reserves is offset and, to a lesser extent, operation cost incurred for generation-based reserve capacity are reduced/avoided.

There are three generic types of reserve capacity:

- Spinning Reserve – Generation capacity that is online but unloaded and that can respond within 10 minutes to compensate for generation or transmission outages. 'Frequency-responsive' spinning reserve responds within 10 seconds to maintain system frequency. Spinning reserves are the first type used when a shortfall occurs. Also known as synchronized reserves.

- Supplemental Reserve – Generation capacity that may be off-line, or that comprises a block of curtailable and/or interruptible loads, and that can be available within 10 minutes. Unlike spinning reserve capacity, supplemental reserve capacity is not synchronized with the grid (frequency). Supplemental reserves are used after all spinning reserves are online.

- Backup Supply – Generation that can pick up load within one hour. Its role is, essentially, a backup for spinning and supplemental reserves. Backup supply may also be used as backup for commercial energy sales.

The amount of reserve capacity needed is driven by electric supply reliability-related standards (typically, 10 to 20% of the normal electric supply capacity).
The benefit from storage used for electric supply reserve capacity is somewhat small because generation-based reserves are inexpensive. Nonetheless, the reserve capacity benefit could be an important element of an attractive storage value proposition because providing reserves using storage has very low incremental cost.

Voltage Support

An important technical challenge for electric grid system operators is to maintain the necessary voltage level and stability. In most cases, meeting that challenge requires management of reactance. To manage reactance at the grid system level, grid system operators rely on an ancillary service called voltage support.
Historically, voltage support has been provided by generation resources that can generate reactive power which offsets reactance in the grid. New technologies (e.g., modular energy storage, modular

generation, power electronics and communications and control systems) make new alternatives for voltage support increasingly viable.
This is an application for which "distributed" storage (storage located close or very close to electricity end-users) may be especially attractive because reactive power cannot be transmitted efficaciously over long distances. Notably, many major power outages are at least partially attributable to problems related to transmitting reactive power to load centers. So, distributed storage – located within the load centers where most reactance occurs – provides especially helpful voltage support.

Black Start

Black start resources are the first to power up to re-energize the grid after a grid-wide outage. Importantly, black start resources must be able to startup without power from the grid and must be able to operate in standby mode, while disconnected from the grid, until they are called upon. In most cases, the black start service is provided by specially-equipped generators. Most storage types are well-suited to serve as black start resources because, unlike generators, they do not need special equipment, and storage does not have to operate while awaiting dispatch.

LONGEVITY OF SITE C NOT VALUED - $1 BILLION

The Alternative Portfolio does not extend to the full 100+ years that Site C is likely to be available to deliver energy. The Site C dam facility which will represent a substantial portion of the Site C costs will have a useful life greater than 100 years. The most likely scenario is for the powerhouse equipment, with a useful life of 70 years, to be refurbished in the same way that wind facilities will be refurbished. A key difference will be that the powerhouse refurbishment will likely be a smaller proportion of costs than the wind refurbishment.

The CEC estimates that this longevity value will create a cost difference between the Alternative Portfolio and the Site C portfolio in the range of 10% of the capital costs of Site C. This value is expected to be in the order of $1 billion, and has been calculated by comparing the Present Value (PV) of the capital investments in each alternative (Site C and Alternative Portfolio) including the differential in the portion of the capital costs needing refurbishment.

WIND COSTS LIKELY UNDERESTIMATED - $600 MILLION

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

Capitalized costs for wind are established at between $263/KW and $297/KW depending on circumstances as shown in the Mid Load Forecast Portfolio cost tab at cells E16 to E29.

Fixed O&M is costed at between $65/KW-y and $66/KW-y (lines E37 – E40) with wind refurbishment and wind (2078 new build) costed at $54/KW-y (lines D45-D48) Additionally, wind integration costs of $2.50/MWh (D52-D56) are added.

The values reflect a Plant Gate cost and the location for wind build has been set to be similar to Site C (Peace Region). (Assumption 5) This was intended to minimize the risk of additional network reinforcements relative to Site C.

BC Hydro's estimate of total Wind Adjusted UEC – Delivery to Lower Mainland is established at $83/MWh before adders and $105/MWh after adders of $22/MWh to reflect the cost to the Lower Mainland, including $5 for wind integration costs[1].

The CEC's estimate of the assumptions embedded in the Alternative Portfolio costs suggest that the total wind costs included in the Alternative Portfolio are in the order of $50/MWh, which is about 47% of Hydro estimate of $105/MWh.

The CEC submits that even assuming a reduction of 45% from BC Hydro's estimate of the base UEC (before adders) the Commission staff have apparently excluded many other costs that should otherwise be included in the wind costs. The CEC finds these to amount to about $18/MWh.

The CEC notes that BC Hydro's Unit Energy Cost for Site C of $43/MWh includes an Adjustment for Delivery to Lower Mainland and annual shape adjustment of +$10/MWh[2] which should not be excluded from the Alternative Portfolio analysis.

The CEC submits that low costs for wind energy are speculative and may not reflect the costs at which the Independent Power Producers (or BC Hydro) would be able to produce and sell electricity.

The CEC estimates the value of this cost differential to be in the order of $600 million.

-Wind Integration

The Alternative Portfolio assumes the integration of wind at cost of $2.5/MWh, which is half of that assumed by BC Hydro ($5/MWh) based on concerns raised in the F18-3 submission, (pp. 14- 17).

The CEABC submission (F18-3) states at page 16:

> Power Advisory studied wind integration costs across many jurisdictions and they are generally estimated to be below $6/MWh and can be as low as $0.50 to $2/MWh even at wind capacity penetration levels beyond 40%, with solar integration costs being lower. This review of variable output renewable energy integration costs indicates that BC Hydro's estimates are considerably higher than most estimates.

[1] A-13, Preliminary Report page 88
[2] A-13, Preliminary Report page 79

In the report submitted by the Clean Energy Association of BC and the Canadian Wind Energy Association Power Advisory LLC states:

> Given the factors influencing wind integration costs...a case can be made that integration costs are more likely to align within a region or market.[3]

The following table is provided.

Table 5: Survey of Recent WECC Renewables Integration Costs

Jurisdiction	Integration Cost ($/MWh)	Year $*	Penetration Level (Capacity Basis)	Notes
Wind				
Arizona Public Service (APS)	3.25 / 4.08	2010	6% (468 MW) / 15% (1,185 MW)	As of the 2017 IRP, APS continues to base integration costs on its 2007 Wind Integration Cost Impact Study. Cost said to be updated "to increased penetration levels of wind in the APS systems and current fuel prices", but the specific value is not provided in the IRP.
PacifiCorp	0.57	2016	30% (3,007 MW)	2017 Flexible Reserve Study (FRS) conducted as part of the 2017 PacifiCorp IRP. Down from $3.06/MWh in the 2014 Wind Integration Study.
Pacific Gas and Electric (PG&E)	4.00	2014	Benchmark Average	Interim variable integration cost for wind approved by the California Public Utilities Commission in the 2014 RPS and IRP off-year proceeding.
Public Service Company of Colorado (PSCo) [Xcel Energy]	2.93	2016	28% (2,000 MW)	2016 ERP. Value based on 2011 Wind Integration Study methodology and updated natural gas prices. PSCo did not allow for gas prices below $3.24/MMBtu, while recognizing current and forecasted gas prices below this value. Average wind integration costs from 2011 were $3.68/MWh for 2 GW of wind.

The CEC considers that the above information does not support wind integration costs of $2.50/MWh, particularly when BC Hydro has declared the costs in BC to be in the order of $5.00/MWh. The CEC considers that the PacifiCorp figure is atypical given the costs in other jurisdictions and should not be used to artificially lower the expected integration costs.

The CEC submits that it is not appropriate to disregard the BC Hydro evidence as to the likely costs that will be experienced with integration.

The CEC submits that BC Hydro will have BC specific costs actual costs that can be examined to assess future wind integration costs.

The CEC recommends that the Commission utilize the BC Hydro costs of $5/MWh unless BC Hydro actuals support a different figure.

The CEC calculates the impact of Wind Integration costs to be double that provided for in the Alternative Portfolio, with an NPV of approximately $80 million more than is included in the Alternative Portfolio.

[3] Page 14

ALTERNATIVE PORTFOLIO POWER EXPORT and SURPLUS CREDITS NOT COMPARABLE - $600 MILLION

Although Site C is not being built for the export market, the CEC submits that the export market provides significant mitigation for the risk of load uncertainty and oversupply. As such, sales to the export market represent an important consideration in an assessment of Site C and the Portfolio Alternative.

The CEC considers that there is a significant qualitative difference in the ability of the Alternative Portfolio to monetize the value of the export and trading market versus that of Site C. The CEC estimates the difference to be in the order of $600 million.

Power and capacity surpluses are costed/priced in Alternative Portfolio as described below. The CEC notes that the Alternative Portfolio treats surplus energy and surplus capacity differently depending on whether or not it exceeds that required by BC Hydro, or whether it exceeds that provided by Site C.

Energy surplus to BC Hydro need (assumption 6)

In any year, if the energy of the Alternative Portfolio exceeds that of the gap to fill, and to the extent that it is surplus to BC Hydro's requirements, the energy is assumed to be exported at a plant gate export price of 2018 $25/MWh. This is based on:

- a forward market F2025 price of Mid-C power of US 30/MWh;
- translated to CAD $ at an exchange rate of 1 CAD $ = USD 0.7979 (CAD $37.60)
- less losses (1.9%) and wheeling costs ($6.3/MWh) to the US/Canada border (CAD $30.59);
- less 11% incremental transmission losses to Site C plant gate location (CAD $27.22);
- adjusted down to CAD $25 to reflect (i) risk premiums inherent in forward market prices; (ii) risk of limited available transmission capacity reducing BC Hydro's ability to access the Mid-C market, and (iii) risk of future downward pressure on Mid-C prices from renewables (such as solar, wind) with low or no incremental generation costs.

Capacity surplus to BC Hydro need (assumption 7)

In any year, if the capacity of the Alternative Portfolio exceeds that of the gap to fill, and to the extent that it is surplus to BC Hydro's requirements, the (Alternative Portfolio) surplus capacity is assumed to have no additional value to BC Hydro (i.e., an export price of CAD $0/kW-year).

Energy Exceeding Site C (assumption 8)

In any year, if the energy of the Alternative Portfolio exceeds that of the gap to fill and is used to meet BC Hydro's domestic load requirements, the cost of the Alternative Portfolio will be reduced proportionally. For example, if the Alternative Portfolio generates 5,564 GWh compared to a gap to fill of 5,286 GWh, only 95% of the cost of the Alternative Portfolio for that year will be included in NPV of the Alternative Portfolio

Capacity Exceeding Site C (assumption 9)

> In any year, if the capacity of the Alternative Portfolio exceeds that of the gap to fill and is used to meet BC Hydro's domestic load requirements, the Alternative Portfolio will be credited with the assumed value of this additional capacity of $50/kW-year. This is referred to as capacity credit in the analysis.

The CEC does not contest the assumptions used for excees energy and capacity of the Alternative Portfolio. However, the CEC notes that similar excesses for Site C are given no credit. The CEC views this as an error in comparable treatment. The CEC has calculated the volume of energy and capacity for Site C in excess of need and applied a value of energy $15/MWh higher than that used by the Alternative Portfolio because of Site C's capacity to generate premium prices.

The evidence presented in the Technical Presentations (October 14th) is that Site C is a highly flexible resource that can be relied on to provide clean, flexible capacity and energy to Powerex's external customers.[4] BC Hydro anticipates rapid change in external markets and a potential capacity void. Customer options for clean, flexible capacity are limited.

Because of the dispatchability BC Hydro will largely be able to choose the hours in which they sell surplus. It is anticipated that Powerex will be able to sell energy in the higher priced hours of the year, and to purchase energy in the lower priced hours. Additionally, Powerex will be able to sell explicit capacity and flexibility products, which earn premiums in addition to any energy delivery.

The CEC submits that it would be appropriate for the Commission to ensure that it has the appropriate evidence available to assess the differences in the capacity values of Site C and that of wind and DSM.

The CEC has estimated the difference in the ability of the Alternative Portfolio and the Site C option as being in the order of $600 million.

UNCERTAINTIES AND RISKS

The risk profile for Site C and for the Alternative Portfolio are quite different.

The Alternative Portfolio has substantial risks as described below.

1. There is a technological risk as to whether or not the full extent of the cost reductions will be deliverable. The Alternative Profile has calculated in one of the deepest cost reduction expectations of the range of forecasts. There is at least a significant risk that its cost efficiency may not be what is in the profile.
2. There is a technical risk that DSM capacity programs will be a flat profile capacity reduction and not a dispatchable one, such as might be obtained through utility controlled demand response on customer equipment.

[4] Transcript October 14, 2017 Testimony of Mr. Bechard

3. There is a technical risk that battery technology will not meet the requirements defined for it in the Alternative Portfolio, particularly given that it is emerging technology.

Site C's technical risk are very different revolving around geotechnical issues, now substantially understood and around workforce efficiency as well as contract supply not yet let.

Site C is being reviewed in a context of potential overrun cost and the Alternative Portfolio does not have the same rigour of costing n the estimates, having the costs sourced from generic studies. Consequently, there is a risk in balance between the two options built into the analysis.

The CEC finds that the risks in the Alternative Portfolio have greater variability and potential consequences to produce more costly results than completing Site C.

The CEC recommends that the Panel advise government that exploration of an Alternative Portfolio need considerably more time and expert systems planning analysis than has been available in the Inquiry period.

The CEC recommends that the Panel advise the government that it weigh heavily the risk to the costs of the Alternative Portfolio.

CEC CONCLUSIONS

The Panel has been asked to provide an Alternative Portfolio to Site C and has assembled what is was able to ascertain from various components of submissions and evidence available in this process.

The CEC submits that the quality of this evidence and the Alternative Portfolio analysis done to date are not very strong, particularly given the nature of errors contained therein.

There is clearly difficulty in creating a spreadsheet model of complex attributes which are integrated in BC Hydro's portfolio modelling and accounting for the electrical system planning issues not modelled or evident at the level the Panel is able to conduct this inquiry.

The Panel is not composed of electrical system planning experts and the evidence in the Alternative Portfolio does not meet prudency levels for system planning. Nevertheless, the Alternative Portfolio and others could have significant benefits in planning for cost-effective supply and are likely options for a future where load growth is driven by policy on electrification.

The CEC recommends that the Panel offer the government the advice that system planning work continues on Alternative Portfolio options but that the evidence is not sufficiently solid that the Panel could offer a firm conclusion as to its benefits at this time.

The CEC submits that the ratepayer impact of cancelling Site C is so substantial that it likely overwhelms the potential benefits of an Alternative Portfolio with such significant uncertainty as to its costs.

The CEC submits that it is important to recognize the overarching evidence that resources such as Site C are Heritage System quality assets with low costs for energy and capacity, particularly given the current sunk and termination costs, as well as ratepayer opportunity costs expected by the CEC to total more than $5 billion.

Site C also provides the opportunity to mitigate the risk of surplus through the export market. To the extent that the future provides significant load uncertainty on the upside through electrification, it remains possible that if Site C is not completed then more expensive versions of similar resources could be required.