# ALLIED HYDRO COUNCIL OF B.C.

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Mr. D.M. Morton
Commissioner/Panel Chair
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

August 21, 2017

Dear Mr. Morton:

**Re: Site C Inquiry Submission**

The British Columbia Utilities Commission recently invited submissions of data and/or analysis until August 30, 2017 into the BC Hydro Site C hydropower project. The Allied Hydro Council of British Columbia is pleased to submit the attached report, "Site C – Review". We believe it factually addresses the questions that have been asked by the Province of British Columbia with respect to the Site C project.

We will be pleased to answer any questions you may have.

Sincerely,

CHRIS FELLER
President

CF/jl MoveUP

Enclosure: Site C - Review

# SITE C – REVIEW


**Allied Hydro Council of British Columbia**

**August 21, 2017**

# SITE C

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## 1. Introduction

On August 2, 2017 the Government of British Columbia ordered the British Columbia Utilities Commission (BCUC) to conduct a review of the BC Hydro (BCH) Site C hydroelectric project to answer several questions. The stated objective of the review is to "ensure BC Hydro rates remain affordable for ratepayers." Subsequently the BCUC Inquiry webpage encouraged British Columbians to participate through submissions of data and analysis until August 30, 2017.

The Allied Hydro Council of British Columbia (AHC) is pleased to submit this "Site C – Review" to the BCUC. We believe it meets the published terms of reference in a factual and informative way.

The AHC was formed on October 4, 1961 in response to a request by Premier WAC Bennett to provide a secure labour supply for the Two Rivers policy.

The initial Collective Agreement was negotiated for the development of hydroelectric power projects on the Peace and Columbia Rivers, incorporating the Columbia Hydro Constructors (CHC) Agreement. The membership in AHC is comprised of 17 international unions, 14 building and construction trade unions and three non-traditional construction trade unions.

Under the AHC/CHC Agreement the following hydropower projects were or will be constructed:

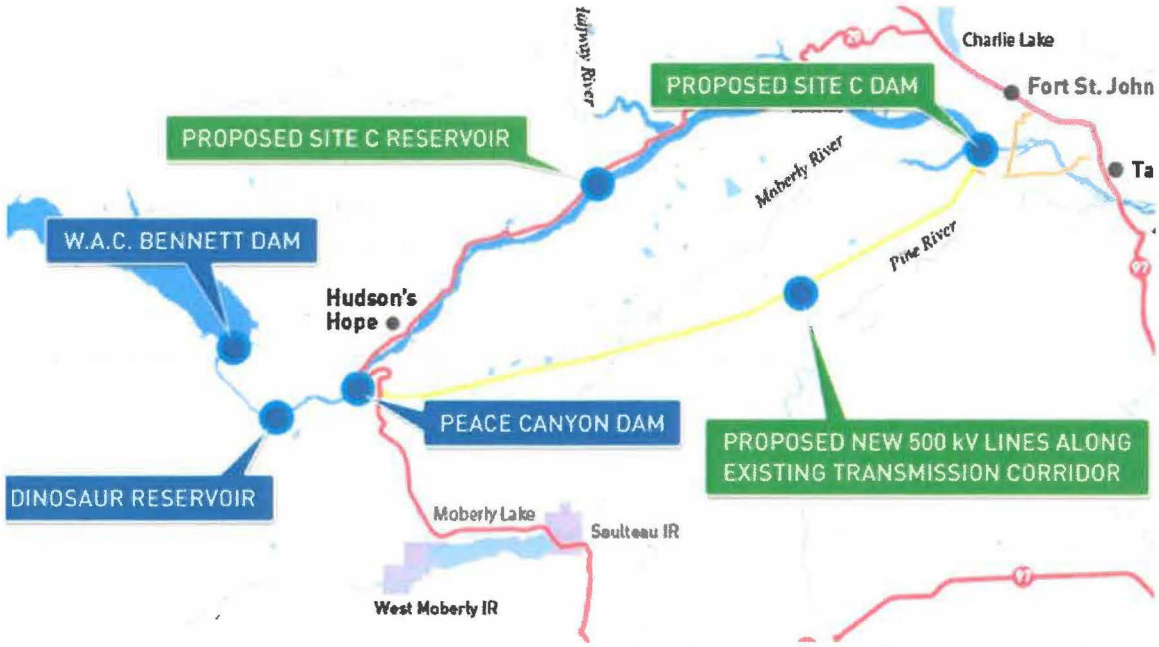
- No. 4 generating unit at Seven Mile;
- No. 5 and No. 6 units at Mica;
- No. 5 and 6 units at Revelstoke;
- Stave Falls power plant;
- Arrow Lakes Generating Station;
- Brilliant Expansion; and
- Waneta Expansion

## 2. The Project

Site C is a long-standing BCH project in northeast British Columbia. Important features of Site C are:

- It is located on the Peace River downstream from the WAC Bennett Dam and Peace Canyon Dam;
- The capacity will be 1,100 megawatts (MW);
- The generation will be 5,100 gigawatt hours (GWH) per year of renewable energy, with 53% availability, enough electricity for about 470,000 BC homes;
- It will have a reservoir 83 kilometres long, which will provide energy storage and dispatch, the ability to produce energy when needed;

- Construction of Site C began in August 2015 and completion is scheduled for 2024;
- The workforce at the site is currently 2,500, which will grow as the Project advances;
- BC Hydro expects the capital cost to be $8.8 billion at completion.




## 3. Province of British Columbia's Questions

The questions asked of BCUC by the Province are as follows:

a) Can Site C be delivered on time by 2024 and within budget;
b) Implications for ratepayers of proceeding with the project;
c) Implications of suspending the project, while maintaining the option to resume construction in 2024;
d) Implications of terminating the project, remediating the site and proceeding with other resource portfolios that provide the same level of benefits at the same or lower cost as Site C; and
e) What are the expected peak capacity and energy demand.

## 4. Review History

In 1980 BCH applied to BCUC for an Energy Project Certificate for Site C. Their application dealt with a number of issues, including: electricity demand forecasts, electrical energy supply, financial impacts, project justification, land use and

environmental impacts, and regional and social impacts. There was a public hearing into the matter.

In 1983 the BCUC published its findings. The conclusion was:

"The Commission does not believe that an Energy Project Certificate for Site C should be issued at this time. The evidence does not demonstrate that the construction must or should start immediately or that Site C is the only or best feasible source of supply to follow Revelstoke in the system plan.

The Commission therefore concludes that an Energy Project Certificate for Site C should not be issued until (1) an acceptable forecast demonstrates that construction must begin immediately in order to avoid supply deficiencies and (2) a comparison of alternative feasible system plans demonstrate, from a social benefit-cost point of view, that Site C is the best project to meet anticipated supply deficiencies."(1)

It should be noted that in the BCH 1980 submission the anticipated capital cost for Site C was $3.2 billion.

In 1990 BCH prepared a "Site C – Status Report". The Report covered a number of areas. It was prepared, BCH, said, "to maintain Site C as a viable option for the future." (2) No action on the project was taken at that time.

In 2010 the then Minister of Energy, Bill Bennett, exempted Site C from a BCUC review, saying, "the BCUC lacked the capacity to review such a project". (3) However, the federal and BC governments in May, 2014, received a report into Site C from a Canadian Environmental Assessment Agency panel.

The report of the panel said, in part, "The benefits are clear. Despite high initial costs, and some uncertainty about when the power would be needed, the Project would provide a large and long-run increment of firm energy and capacity at a price that would benefit future generations....There are other considerations. The scale of the Project means that, if built on BC Hydro's timetable, substantial financial losses would accrue for several years... There are alternative sources of power available at similar or somewhat higher costs...These sources, being ...smaller than Site C, would allow supply to better follow demand, obviating most of the early-year losses of Site C....the policy constraints that the BC government has imposed on BC Hydro have made some other alternatives unavailable."(4)

The Head of the panel later said that a lower cost option would be to take back the power available under the Columbia River Treaty. Notwithstanding, the report evidently justified the government's decision to proceed with Site C.

Site C construction began in August 2015.

## 5. Forecast Peak Capacity and Energy Demand

The most recent forecast of BC electricity demand is the 2013 BC Hydro "Integrated Resource Plan". [5]

While BCH will produce another Integrated Resource Plan in 2018, in 2016 BCH updated their long term forecast. [6] This forecast was used in the 2016 BC Hydro Revenue Requirements Application. [7]

It shows electricity demand in 2017 at 58,000 GWh and capacity of 11,000 MW, this is a reduction from the 2013 forecast due to market changes in the large industrial sector, mining, LNG and the forest sector. The updated forecast notes considerable uncertainty in the market.

In 2024 capacity needs are 12,000 MW and generation 65,000 GWh. In 2036 capacity requirements are 14,000 MW and generation 72,000 GWh.

The growth to 2024 is about equivalent to one Site C and to 2036 about three Site Cs.

BCH's electricity requirements forecast from 2017 to 2036, 20 years, has an average annual growth rate of 1%. In the 48 year period from 1965 to 2013 requirements grew by an average of 3.41% per year. It is beyond the scope of this Review to produce an independent electricity requirements forecast, but it appears that the recent BCH forecast is quite conservative and that new sources of supply are needed. The Assessment Agency Clean Energy Project report said: "The Panel concludes that BC Hydro's forecasting techniques are sound, but uncertainties necessarily proliferate in long-term forecasts."

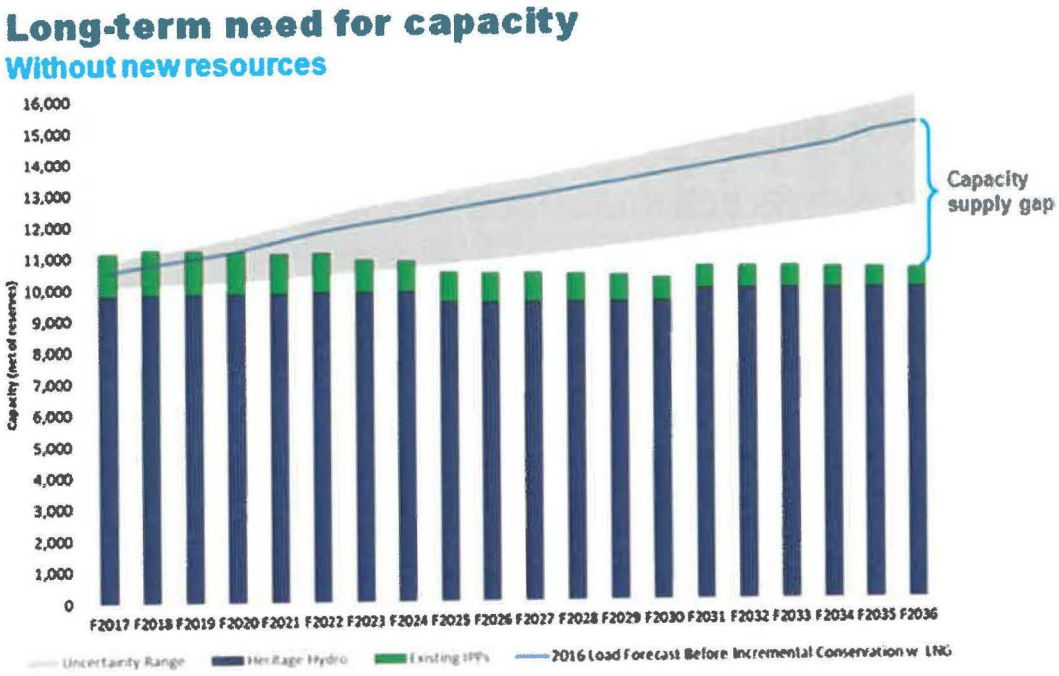
It should be noted that contrary to some public opinion, the BCH forecasts do not include significant amounts of electricity for LNG plants.

In 2012 there were 5 LNG plants proposed for BC that could produce 24 million tonnes per year of LNG. The electricity needed, according to the Clean Energy Association, would have been 21,000 GWH, 17,000 GWh from gas generation and 4,000 GWh from renewables. [8] In 2015 the BC government reported that there were 23 proposed LNG projects. Most of these proposals were for plants employing Direct-Drive technology, which uses natural gas for cooling and compression in the process, rather than the E-Drive technology, that uses electricity for processing LNG. A 7 million tonne per year E-Drive plant would require 800 MW of electrical capacity. [9] LNG Canada, like most, would use Direct-Drive technology and BCH power just for ancillary plant requirements, a relatively small amount.

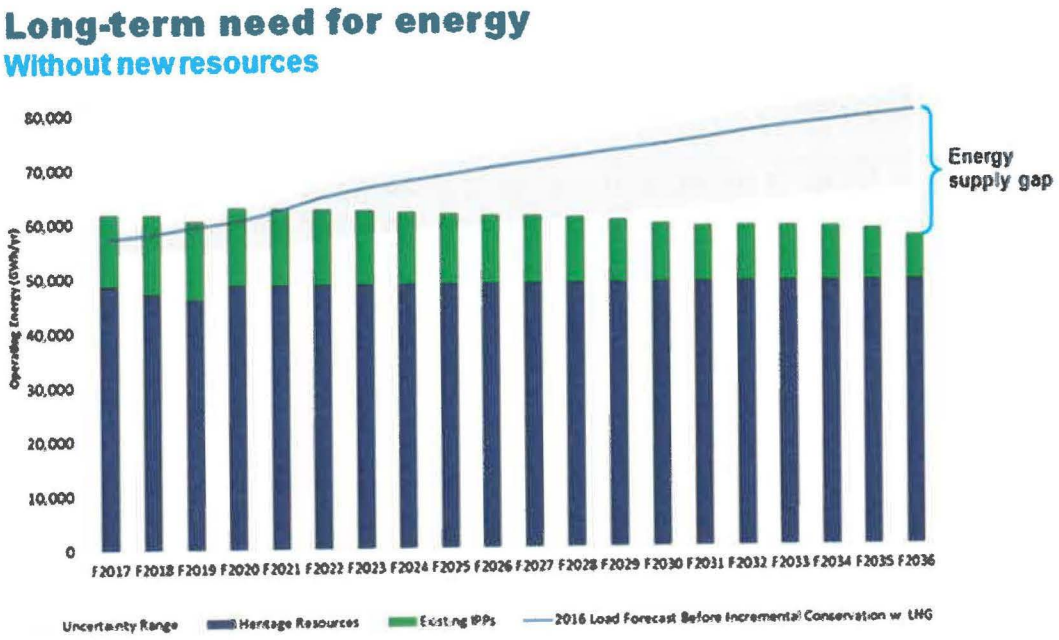
The BCH 2016 forecast only includes the Fortis BC Tilbury Island plant, which is under construction; the LNG Canada Project in Kitimat, only for its ancillary needs, this project is awaiting an investment decision; and the Woodfibre LNG Squamish Project,

electricity for both compression and ancillary needs. BCH's forecast has 2,662 GWh in its forecast, not 21,000 GWh or some multiple number.

It should be noted here that BC was a net importer of power for seven out of the eleven years between 2005 and 2016. BCH stores energy when demand is low, then generates and exports it when demand and prices are high in the USA




Note, these forecasts include incremental conservation and LNG.



Factors that could influence demand include:

- Slowing economic and population growth. But neither are expected in the medium term;
- The cancellation of additional LNG projects. However, as noted above this is not a large component of the BCH forecast;
- Electric cars. While only 2 % of the current automobile market, these vehicles are predicted to see a rapid expansion, up to 14%, which could create a significant increase in BC power demand. [10] [28]

## 6. Site C On Budget, On Time

The record will show that BCH has not had a good record in completing their projects on budget and on time. A recent example is the Northwest Transmission Line (NTL) from Skeena Substation to Bob Quinn Lake. This 344 kilometre line to mines and hydropower resources was completed in 2014, behind schedule. The original cost estimate was $404 million, but due to difficult terrain and other problems, was completed at a cost of $736 million. [11]

Like most other Canadian utilities carrying out major capital projects, BCH uses the traditional design-bid-build (DBB) procurement process.

DBB has a number of advantages: the owner has full control, DBB is a familiar process for utility managers, regulators like it, contractors and suppliers also like it because there is less competition and risks for them.

In DBB the owner bears most of the project risks, which can be a major cost driver for hydro projects, and often there is a disconnect between the designer and the contractor(s).

This disconnect can lead to misunderstandings, scope changes, change orders, contract disputes, claims, delays and cost overruns.

There are other forms of project procurement, including design-build (DB), which have been shown to be more effective, less costly and more conducive to innovation than DBB.

In fact it is the stated policy of BCH's owner, the Province of British Columbia, to require their agencies to consider other procurement forms, such as P3s, in all projects greater than $25 million.

In the "Review of BC Hydro" the BC Ministry of Finance said "the corporate culture in BC Hydro...result(s) in desire to have the gold standard (which) is not necessarily for lowest cost or greatest value...BC Hydro needs to...improve its procurement management...despite the move towards more innovative Design Build models

recently, they...rely on traditional procurement approaches...(where BC Hydro used DB) BC Hydro controlled the project...mitigate(ing) the ability to effectively transfer risks to their vendors."[12]

Site C is now 2 years into construction. While its traditional DBB procurement approach may have been modified somewhat for Site C, there is little indication of a significant change in approach. BCH have awarded or intend to award multiple contracts for: turbines and generation equipment, road improvements, site preparation, civil works, mechanical equipment, and the powerhouse.

In an article "Hydroelectric Projects – Risks and Management" the following cost comparisons are shown for independent power producers (IPPs) and utilities. [13]

Table 1 Cost and Procurement Method for Various IPP and Utility Projects

IPPs

| Project | MW | $Mill | $Mill/MW | Year | Form |
|---|---|---|---|---|---|
| A. | 185 | 279 | 1.5 | 2002 | DB |
| B. | 9 | 36 | 4.0 | 2009 | DBB |
| C. | 120 | 208 | 1.7 | 2007 | DB |
| D. | 196 | 660 | 3.4 | 2010 | DB |
| E. | 150 | 405 | 2.7 | 2010 | DB |
| F. | 49 | 137 | 2.8 | 2006 | DB |
| G. | 335 | 930 | 2.8 | 2014 | DB |

Utilities

| Project | MW | $Mill | $Mill/MW | Year | Form |
|---|---|---|---|---|---|
| W. | 24 | 95 | 3.8 | 2009 | DBB |
| X. | 135 | 1,053 | 7.8 | 2017 | DBB |
| Y. | 1,100 | 7,900 | 7.2 | 2022 | DBB |
| Z. | 200 | 1,340 | 6.7 | 2012 | DBB |

In this table projects A through G are all BC projects built by IPPs. Several are Columbia Power Corporation projects.

Three of the utility hydro projects are BCH projects, W, X and Y. X is John Hart with the cost estimate based on DBB procurement. For John Hart the Province required BCH to follow a non-traditional procurement approach, a design-build-finance-rehabilitate (DBFR), but BC Hydro has amended it to be more of a DBB approach. Y is Site C, based on an earlier cost estimate, where the estimate again is using DBB.

The average capital cost for the IPP projects is $2.5 million/MW of capacity. For the utility projects it is $5.9 million/MW, over 200% higher. While there are a number of other factors involved here, this appears a significant difference.

Given this information, if a decision is taken to proceed with the completion of Site C the procurement strategy should be reviewed to see if, even at this stage, the strategy could be improved. There may be significant potential savings and enhanced prospects for completing the project on budget and on time.

However, another very important point must be made here. While the capital cost of Site C is greater than most IPP hydropower projects, over the years Site C capital costs have not risen sharply.

In 1980 the capital cost estimate was $3.2 billion; in 2011 $7.9 billion; in 2017 $8.8 billion. The cost escalation here is an average of 3% per year, about the same rate as the BC Consumer Price Index (CPI). If the Site C capital cost continued to escalate at this same 3%, which is highly conjectural, the in-service cost starting from the $8.8 billion base would be $10.8 billion. However, as will be set out below, the $8.8 billion cost is not a valid base for assessment.

## 7. Proceeding With The Project

Economic Viability

The economic viability of Site C is basically a function of the cost of generating electricity, the requirement in the market for that electricity, and the price at which this electricity can be sold with a reasonable return on investment.

In economic analysis there are both short run and long run marginal costs concepts. In the short run, the only costs that matter are variable costs, mostly operating costs, nothing can be done about fixed costs. Thus a profit maximizing plant owner will produce an extra unit of output if its marginal cost is less than or equal to the market price for that product.

In the long term all costs are variable, costs are incurred only if there is a plant to produce output. The investor will build and operate a new plant if it is expected that going forward the plant capital cost (including the interest on capital), the maintenance cost and the operating cost on a present value basis, will be less than or be equal to the present value of future product sales.

The long run marginal cost of hydropower is fundamentally the capital cost of the new plant, because on-going operating and maintenance costs are low. When the BC government conducted the 2011 "Review of BC Hydro" the capital cost for Site C was $7.9 billion. For a 70-year project life at a 6% discount rate (the cost of capital), with sustaining capital, water rentals, operating costs, grants-in-lieu and taxes (for a sub-total of $11.67) added in, the all-in long run unit energy cost was shown to be $95.00 per megawatt hour (MWh). Using the more conventional BC government 8% discount rate, the all-in cost was $136.00/MWh.

Whether Site C unit costs of $95.00/MWh or $136.00/MWh made it an economically

viable project at that time is not clear from this analysis alone. The important question is, what were the alternatives? This question is dealt with later.

The BC power market like most in the rest of Canada and the USA is not a competitive market; there are not many sellers. These markets are dominated by 'natural monopoly' utilities. This is why the utilities are regulated as to price, allowable costs and product need.

It should be noted that the BCUC, like other regulators, do not price electricity at the value of long run marginal cost. They set power rates at a level which is intended to cover long run average costs, the costs of old facilities with the costs of new facilities rolled in. So if a new plant is large and costly that will raise average cost and power rates.

The current capital cost of Site C is estimated to be $8.8 billion. The other operating and tax costs, as shown above, should be roughly unchanged at $11.67. Thus arriving at a dependable assessment of 2017 Site C unit energy cost should be straightforward. The cost can be looked at using both a 6% discount rate and an 8% discount rate. In doing so, an investor now looking to invest or not invest in Site C, at a more conservative project life of 50 years, not 70 years, would find that at a 6% discount rate the all-in Site C unit cost is $109.50 + $11.67 = $121.17/MWh and at 8% discount it is $141.05 + $11.67 = $152.71/MWh.

However, a very important point must be made here. That is, since the question is economic viability, another economics concept is required to be considered here. That is the concept of "sunk cost".

A sunk cost is a cost that has already been incurred and cannot be recovered. Only prospective (future) costs are relevant to an investment decision. Sunk costs should not affect a rational investors decision.

Prior to August, 2015, before construction start, BCH, the investor, was looking at a Site C capital cost of $8.8 billion, little of which at that time was a sunk cost. This prospective cost would have resulted in all-in unit power costs of either $121.17/MWh or $152.71/MWh, as set out above. Both are above BC Hydro average costs and compare to the current residential rate of $85.80 /MWH for the first 1,350 kWh of service and $128.70/MWh for service above 1,350 kWh. The commercial rate is $113.90/MWh and the industrial rate much lower. So the Site C unit cost, if fully allowed by BCUC, would have tended to put upward pressure on power rates.

BC Hydro says as of June, 2017 it has spent $1.75 billion on Site C. It has also been reported "A further $4 billion has been committed, in the form of signed contracts, and community and First Nations agreements..... There would also be remediation costs if an order were given to abandon the operation.... In short, the financial consequences of a stop order are enormous....If it were abandoned entirely, the better part of $6 billion would have to be written off." (14)

Therefore, with the BC government facing a decision on the future of Site C, the questions are: delay it and incur more costs; cancel it and write off major costs; or proceed with it and spend more?

At this point a rational decision maker will carefully consider how much of the cost is a sunk cost. If it is not the full $6 billion referenced above, but more conservatively, assume it is one-half that amount, $3 billion, then the future capital cost Site C would be $8.8 billion - $3.0 billion = $5.8 billion. While this economic argument may not persuade all, it is still a valid argument. The question of the accounting treatment of the assumed $3 billion sunk cost is dealt with below.

At a capital cost of $5.8 billion the all-in unit cost, capital, operating and taxes, over a 50 –year life would be $83.83/MWh or $104.63/MWh, for a 6% and an 8% discount rate respectively.

Would proceeding with Site C at these unit costs be a rational investment decision? As shown above the BCH forecast shows that there will be a market for at least this amount of power in 2024 and into the 2030s.The investment decision, in part, would depend on the alternative power sources available, these are considered below.

Should Site C proceed or be terminated on the basis that $3 billion are sunk costs, there would be regulatory and financial issues to be addressed. Would BCH in the case of termination write-off $3 billion on their books, with the cost borne by the owners, that is the BC taxpayers? Or would the $3 billion be allowed by BCUC to be included for rate setting purposes and be borne by ratepayers? In the case of proceeding, would the full $8.8 billion be allowed by BCUC for ratepayers?

Export Markets

There has been a concern, despite the BCH forecasts, that Site C may generate some amount of surplus power. If there was surplus Site C power that could be a benefit, not necessarily a negative factor. This is because there are possible near-by, new markets for green BC energy.

First, with the government of Alberta taking a policy position that coal-fired power must be phased out soon, there has been some discussion about the feasibility of building a new transmission line from the Site C project to Alberta. To this point the idea has not advanced as the future of Site C is not yet determined.

In addition to Alberta, a possible opportunity would be for some power exports to Alaska. It is a huge region with minimal power generation and transmission infrastructure and the state is not connected to the North American Power Grid. Alaska supplies much of its power, 135 MW of capacity, from diesel generation, about 50%, which is expensive and polluting. The cost of diesel power in Alaska averages $350/MWh.

In 2006 the Alaska Energy Authority commissioned a feasibility study into the AK-BC Intertie, a power line to connect Alaska to BC. Another report was completed by Alaska in 2014, indicating a possibility of Alaska subsidizing the development of a transmission line. The feasibility studies showed clear benefits but the AK – BC Intertie was not built, due in part to worsening state finances with falling North Slope oil prices.

BCH recently completed the 287 kV Northwest Transmission Line (NTL) from the Skeena Substation to Bob Quinn Substation, 344 km, to serve northwest communities and mines, including Forest Kerr mine. The cost of the NTL was over $700 million. The NTL runs very close to the Alaska border and the AK-BC Intertie could connect the NTL to the Alaska transmission system.

In 2014 an "AK- BC Intertie Business Case Assessment" was completed for a major Canadian energy company. Without releasing confidential information, the Assessment showed that the capital cost of the AK - BC Intertie would be in the $200 million range. The potential BC electricity supply to Alaska could be up to 500 GWh/year by 2050. However, there could be significant environmental and First Nations issues for the AK-BC Intertie. (15)

The AK-BC Intertie has not advanced but could be an opportunity for excess Site C power.

Risks

The risks of proceeding with Site C include:

- Demand forecast errors – too low, too high – but likely the risk now is more on the low forecast side with possible, but not certain, further LNG plant cancellations being at least partially offset by electric vehicles over the long term;
- Site C budget again rises – there is a history of this for BCH and other Canadian utilities, for example the Newfoundland, Nalcor Muskrat Falls 824 MW hydropower project with a budget now of $12.7 billion up from the original $7 billion. (16) But a more effective procurement process could be off-setting;
- Further court challenges; (17) and
- Potential impacts of climate change on hydropower stream flows. BCH has published a study on this risk, looking at all BC regions. For the NE the study concludes that:
  "Climate change scenarios for the Williston reservoir project an increase in inflow ranging from 11percent and 15 percent by the 2050's...There is evidence for an earlier freshet onset and a shift in the peak flow from June to May. Summer flows are projected to decline, with the greatest decline in July." (18) Hence these changes may shift the profile of power output at Site C but could as well increase the amount of generation, the availability factor.

## 8. Suspending the Project

BC Hydro has said that as of June, 2017 it has spent $1.75 billion on Site C. It has also been reported, as noted earlier, that "a further $4 billion has been committed, in the form of signed contracts, and community and First Nations agreements ...There would also be remediation costs if an order were given to abandon the operation...In short, the financial consequences of a stop order are enormous... If it were abandoned entirely, the better part of $6 billion would have to be written off."

This cost analysis, has not been substantiated, and applies more for a cancellation than a delay. The delay costs for one year have been estimated based on possibly preventing the diversion of the Peace River in September 2019 to 2020, [19] resulting in lost energy revenues of about $500 million, that is 5,100 GWh X $100/MWh. Added to this for a one year delay are costs from on-going projects, maintenance, civil works contracts, workers fixed accommodation costs and interest on costs, for another $630 million. [20] Thus a one-year suspension cost of roughly $1 billion. This does not include lost wages for laid-off workers. And, this is for one year, not a potential seven-year suspension to 2024.

In addition to these suspension costs is another important issue. If Site C is suspended and does not then come into service until 2031, 2024 plus 7 years, other sources of power will be needed in BC. During the suspension there will be great uncertainty for industry as to supply and cost of power as well as for energy project investors, concerned with whether or not their energy will be required. New energy projects in BC will generally take at least 5 to 7 years to design, permit and build, so the gap may need to be filled in another way. There are currently not a large number of projects in the BC development cue. The result could be that to fill the suspension energy gap BC would have to import power, at an unknown cost and without the security of a domestic supply.

## 9. Terminating the Project

The termination of the Site C project would have a number of significant consequences.

<u>Lost Development Benefits</u>

- Security of domestic energy supply if imports are required;
- Direct/indirect construction employment jobs, 2,500 currently and rising going forward;
- Low greenhouse gas (GHG) power source if replaced by combustion technology;
- Relatively low cost, long-term power supply; and
- Reservoir power storage capacity to provide dispatchable energy and support for wind, solar, run-of-river hydropower and other renewables.

Termination Economic Impact

- Lost capital investment, possibly $3 to $6 billion;
- Increase in BCH power rates if sunk costs allowed by BCUC, without any ratepayer benefit, or reduction in the book value of BCH, and loss to tax payers of asset value;
- Lost sales revenue of about $500 million per year;
- Need for new sources of supply: DSB imports, other imports, new IPP projects, gas-fired power plants, or many new bioenergy plants; and
- Significant new sources of supply are now not available in the short to medium term and could have fewer benefits than Site C, be more costly.

## 10. Other Resource Options

a) Conservation

BC Hydro has for some years had various programs to encourage electricity conservation. There has been the Power Smart program focusing on providing savings tips, new technologies, subsides for retrofits, etc. BC Hydro says it has spent $1.4 billion on conservation since 2002.

BC Hydro has the demand side management (DSM) program which for residential customers (about 40% of total consumption) has focused on the 2-step rate schedule, $85.80/MWh for the first 1,350 kWh and $128.70/MWh for additional electricity over an average 2-month billing period. As of 2017 BCH residential monthly power rates compared as follows: [21]

Table 2 Residential Power Rates (cents/kWh)

| | |
|---|---|
| • Vancouver | 10.29 |
| • Toronto | 14.31 |
| • Montreal | 7.19 |
| • New York | 28.90 |

The average BC home consumes 10,800 kWh/year of electricity. The average for Canada is about 12,000 kWh/year, similar to the US, about twice that of France and most of Europe. Power price, climate and home structures play major roles here.
In the BCH 2013 Integrated Resource Plan the demand forecast showed growth from 2013 at 59,000 MWh growing to 85,000 MWH without conservation in 2033. With conservation the figure was 70,000 MWh. The BCH goal, the Plan says, is to meet "at least 66% of the expected increase in demand through conservation and efficiency by 2020." BCH says that in 2016 cumulative conservation energy savings were 5,091 GWh.

BCH has raised power rates several times recently and the 10 Year Plan has rates rising by 4% in 2017, 3.5% in 2018 and 3% in 2019.

In short, through government direction and their own initiative, BC Hydro has had some success in conservation. However, even with more conservation there will be additional electricity needs, likely in the 10,000 to 14,000 GWh by the 2030s, keeping in mind the forecast uncertainty.

b) Return of the Columbia River Downstream Benefits from the USA.

The 1964 Columbia River Treaty (CRT) principal features are:

- Three storage facilities were to be developed and operated on the Columbia and Kootenay rivers.
- Most of the obligations and benefits under the CRT were transferred by Canada to BC.
- The principal purpose of the CRT was to provide flood control and power generation improvements for the US, with financial and power supply benefits returning to BC/Canada.
- BC Hydro built facilities at Mica, Keenleyside and Duncan, a total of 15.5 million acre-feet of storage, most of it at Keenleyside and Mica.
- The CRT allowed the US to build Libby dam in Montana in 1973 without any compensation to Canada although BC power plants did benefit from regulated flows at Libby. There are flood control benefits as well. The US obligation to coordinate flows with Canada at Libby continues whether or not there is a CRT.
- Water levels in Kootenay Lake are regulated by the International Joint Commission (IJC) under the Kootenay Lake Order. The Order is administered by FortisBC.
- The CRT requires operation of Libby to be consistent with the Order.
- BC receives 50% of the additional power generation made possible in the US, the "Downstream Benefits" or DSBs.
- The DSBs are 1,250 MW of capacity, 4,000 GWh/year, valued at roughly $150 million/year priced at $38/MWh, roughly equal to the average market price at Mid C in Washington State; also valued at $515 million/year priced at $129/MWh, what BC Hydro has said in the past is the cost of firm replacement clean energy.
- The first value equates to $1.688 billion and the second $5.798 billion, in present value terms over 30 years at 8% discount.
- Under the CRT BC and the US develop Assured Operating Plans (AOP) every five years focusing on flood control and power generation. The AOP is used to calculate the DSBs.
- There are also annual Detailed Operating Plans (DOPs).
- BC Hydro, Army Corps of Engineers and Bonneville Power Administration develop and implement the AOPs and DOPs.
- The priority of water use under the CRT is: 1) consumptive uses; 2) flood control; 3) firm energy; 4) reservoir refill; and 5) secondary energy.
- Water Use Plans in BC and Variable Flow operations (VARQ) in the US have superseded CRT operating plans in a number of instances, sometimes with compensation to the other side.
- The CRT can be terminated by either Canada or the US unilaterally at any time after September 16, 2024, if notice is given by September 16, 2014.

- However Canada cannot give notice of termination without consent from BC.

The US Bonneville Power Administration and US Army Corps of Engineers made their final recommendations on the CRT to the US federal government in December, 2013 .The recommendation is to "modernize" the CRT.

The US Entity says the Canadian DSBs are significantly larger than the value of coordinated power operations (the US implies the power benefit from the CRT is equal to just 10% of the DSBs).

BC, it is understood, does not accept the US position and on March 13, 2013 announced "the decision to continue the Columbia River Treaty and seek improvements within its existing framework."

British Columbia says the only benefit to Canada of continued coordination under the Treaty beyond 2024 is the return of the Canadian Entitlement, which is one-half the incremental downstream power potential resulting from the Treaty operations.

According to the Province, beyond the DSBs, it receives no benefits from coordination of flows for power generation or flood control. The DSBs, BC says, in fact are less than 50% of the benefits the US receives from CRT coordination for flood and power purposes. [22]

Thus the DSBs are roughly equivalent to Site C in terms of capacity and energy. The DSBs could be taken back to BC from the USA, so they may appear to be "free". But that would require the construction of a new, high voltage power line (230 kV to 500 kV). Such a transmission line could cost about $2million/km, based on BC Hydro's Northwest Transmission Line (NTL) cost, so in the range of $500 million to $750 million.

Currently BCH sells the DSBs in the Washington/Oregon market at relatively low prices, low because of heavily subsidized green wind energy supplies in those states. The price has been in the US$35/MWh to US$50/MWh for some time. If BC Hydro was to take back the DSBs this price would be the "opportunity cost" of the supply, the lost revenues – it is not really free.

In addition to the transmission line investment and opportunity cost considerations are others. BCH has consistently said that it would not want to rely on more than 500 MW of DSBs because they essentially are imports and security of supply is an issue (perhaps more so given current US trade policies). The long-term future of the DSBs is not certain. As noted, the US could terminate the CRT at some point, although no notice has yet been given.

It is worth, however, considering what the cost of supply would be should BC repatriate 500 MW of DSBs and the associated energy, about 1,600 GWh/year. The opportunity cost, as indicated would be about $60 million/year. The capital cost for the $500 million

transmission line plus the opportunity cost would be $107 million/year, which would indicate a unit cost of roughly $105/MWh, assuming a 30- year arrangement.

c) Independent Power Producers (IPPs)

In 2016 BCH reported that it had electricity purchase agreements (EPAs) with 119 independent power producers (IPPs,) many of which are non-storage, run-of-river hydropower generators. [23]

The makeup and some features of these EPAs is as follows:

- Wind – 7 EPAs, 702 MW, 2,060 GWH, 33% availability;
- Gas-powered – 2 EPAs, 380 MW, 3,140 GWH, 94% availability, new projects contrary to BC Environmental policy;
- Hydropower - 80 EPAs, 3,270 MW, 12,000 GWH, 42% availability, some dispatchable;
- Bio-energy – 24 EPAs, 850 MW, 3,450 GWH, 46% availability, dispatchable.

In 2016 it was also reported by BC Hydro that the lowest EPA contract price was $76.20/MWh, the average price was $100.00/MWh, and the highest price was $133.80/MWh for firm power during the peak winter season. IPPs in 2016 supplied 20,454 GWh of electricity to BC Hydro about one-third of its total supply. BC Hydro will pay $58 billion to IPPs over the life of the EPAs.

It may be useful here to consider the contract arrangements for one of the most recent IPPs to begin operations with an EPA.

From public information it is known that the Waneta Expansion Project is 51% owned by Fortis BC and 49% by Columbia Power/Columbia Basin Trust. It has 335 MW of capacity and annual energy of 630 GWh. The capital cost was $930 million. Fortis takes the full capacity and related energy and BCH buys the surplus energy. The prices are $13,000 per MW month and $80.00/MWh for energy.

The total revenue then accruing to the Waneta Expansion is $102.7 million/year. At a 6% discount rate, over 50 years, the unit capital cost would be $93.66/MWh. With taxes and operating costs at $12.00/MWh the cost would be $105.66/MWh, about equal to the total revenue on a unit basis. At an 8% discount the unit cost would be $132.70/MWh, so somewhat greater than the revenue stream.

Thus IPP hydropower supply is a significant factor, it is renewable, and it has a current unit cost of roughly $100/MWh to $120/MWh. And, there are many potential new hydropower projects in BC. [24] However, in many cases the projects are some distance from BCH transmission lines and this power as run-of-river has no storage capacity, which are disadvantages.

More detail on other resource options is given below.

i) Wind

Wind power is a rapidly growing renewable power sources around the world. In 2016 the world total was 432,883 MW of capacity. China had 145,362 MW and Canada 11,205 MW. [25]

Capital costs for new wind projects in BC vary depending upon several factors. Cape Scott Wind 99 MW, had a capital cost of $3.3 million/MW; Melkie Wind, 185 MW, $2.2 million/MW. [26]

From general industry information it appears that the cost of turbines, construction, overheads and contingencies for a green-field site in BC would be in the range of $3 million per MW of capacity. For a brown-field site the all-in capital costs could be lower. For a small 15MW plant the capital cost would be expected to be in the C $45 million range. 15 MW is used here because that is the maximum size of IPP BCH's Standing Offer program allows, the only operating program currently in place.

The availability to generate wind power is a function of the strength and frequency of the winds. The average availability tends to be in the 25% to 35% range. Thus a 15 MW plant will generate power only for about 90 to 130 days per year. That means about 40,00 MWh/year, which would translate into a unit capital cost of about $100/MWh, over a 30 - year project life, before operating, tax, and maintenance costs.

For larger plants the unit cost may be somewhat lower. The Canadian Wind Association has said that in Quebec in 2016 Hydro-Quebec recorded a new low average price for wind power in Canada of $63/MWh (the basis of this number is not available and thus should only be taken as indicative).[27]

In short, wind power is a good source of green energy, and its costs are falling. The unit cost now is in the $100/MWh range. However, with a low availability wind is not highly dependable. Wind needs a base power supply, gas-fired plants or hydropower reservoirs as back up. Possibly in the future energy storage in batteries will provide a source of backup for wind. [28] At this time wind can only be considered as a source, not a major source of BC power supplies. In addition, wind power has been criticized for its impact on bird populations.

ii) Natural gas combined cycle turbine plants

Combined cycle gas turbine (CCGT) power plants are much more efficient than the older single cycle plants, over 50% efficiency versus 30%. ENMAX, a major Canadian utility, recently built an 800 MW CCGT plant in Alberta. The capital cost was $1.3 billion, or $1.63 million/MW of capacity. The plant is about ¾ the size of Site C in terms of capacity and will have a greater than 90% availability factor versus Site C at about 53%.

With plentiful supplies of natural gas, CCGT plants could be a major new source of BC power supply. They do, however, produce greenhouse gases (GHGs), and are thus contrary to the BC government's current environmental policy.

The economic feasibility of CCGT plants depends very much on the future price of natural gas. In the article "Canadian Hydropower in the Pacific Northwest" the cost of CCGT power from a new plant is shown. [29]

Table 3 CCGT Unit Costs

| | |
|---|---|
| Capital total $870 million | $18.85/MWh |
| O&M | $5.00/MWh |
| Fuel @ $6.00/MMBtu (MCF) | $40.25/MWh |
| GHG tax * | $6.60/MWh |
| Total | $70.70/MWh |

* Greenhouse Gas tax

The current market natural gas price at the Henry Hub in the USA is US$3.07/ MMBtu, or C$4.15/ MMBtu. The National Energy Board is forecasting a price in 2040 of US$4.55/MMBtu, or C$6.15/MMBtu. The World Bank is forecasting the price in 2030 of US$5.00/MMBtu, or C$7.45/MMBtu.

It would therefore appear that should BCH consider a CCGT alternative to Site C, and environmental policy allow, the cost comparison would be a unit cost of about C$$70 to C$75/MWh.

iii) Bioenergy

Bioenergy is derived from organic, biological sources. The energy is stored in a chemical form containing carbon, oxygen and hydrogen elements. Wood, for example, is 49% carbon, 6% hydrogen and 44% oxygen. Those elements combine into organic polymers, cellulose, hemicellulose and lignin in wood. Wood, wood waste, municipal waste, agricultural waste, sugar cane, and many other organic sources can supply bioenergy.

Bioenergy can be recovered in a liquid fuel form as ethanol or diesel fuel as well as in the form of synthetic natural gas (syngas), which is methane. These fuels can be used to generate electricity or used as motor fuels. Conversion of organic chemicals into liquids or gas is not necessary, however, and bioenergy can simply be burned to produce heat and stream to drive turbines for electricity generation.

Biofuels are usually considered as renewable sources of energy because they produce no net greenhouse gases (GHGs) when consumed and have a useful energy by-product, electricity or vehicle fuels. However some environmental groups disagree and say that GHGs are still GHGs.

The BC forest industry has been using bioenergy to fill power needs at their sawmills, pulp and paper operations for many years. There is roughly 800 MW of electricity generating capacity in the forest sector now. The first non-integrated bioenergy plant selling power to BCH as an IPP was the Williams Lake facility in 1988 with 68 MW of capacity using sawmill waste.

Through its various Calls BCH now have in addition to Williams Lake a number of other EPAs. Some of these are the 2 MW Hartland Landfill project, the 6 MW Vancouver Landfill project, the 78 MW Celgar Green Energy project, the 60 MW PGP Bio Energy project, the 1 MW Cedar Road project, the 20 MW Armstrong Wood Waste Co-Gen project, the 51 MW Skookumchuck Power Project, the 112 MW Howe Sound Green Energy project, the 76 MW Kamloops Green Energy project, the 38 MW Powell River Generation project and the 8 MW LP Golden Biomass project.

Through its 2010 Bioenergy Call BCH received 19 proposals and selected 4 of them. They are: the 12 MW Chetwynd Forest Industries Biomass Project, the 40 MW Fort St. James Green Energy project, the 12 MW Fraser Lake Sawmill Biomass project, and the 40 MW Merritt Green Energy project.

The Northern Bioenergy Partnership consisting of government agencies, business groups, banks and First Nations was formed to promote the expansion of bioenergy developments in the northern part of the province. The University of Northern BC and Nexterra joint ventured to build a plant to supply heat to UNBC campus. It produces syngas from wood waste.

While perhaps no longer relevant, the BC government's 2007 Energy Plan had several goals related to bioenergy. They were:

- Electricity self-sufficiency by 2016;
- 93% of total electricity generation from renewable energy sources;
- Clean Energy BC Hydro Calls;
- Zero net GHG emissions from thermal power plants by 2016;
- Encourage ethanol substitution for gasoline;
- Encourage IPPs to develop most new power sources; and
- Biofuel production to meet 50% of renewable energy requirements by 2020.

The Province set out a "BC Bioenergy Strategy". A $25 million fund was established to support bioenergy projects. Besides capturing useful energy from organic wastes, a major impetus for the Province's bioenergy support has been a necessity to deal with the huge supply of mountain pine beetle damaged timber.

The Special Committee on Timber Supply several years back reported that 53% of the total pine value on the timber harvesting land base had been killed. Eighteen million acres had been affected.

The First Nations claim 14% of the annual allowable cut (AAC) licences on their lands in BC, much of this in mountain pine beetle zones. They are looking to establish joint

ventures with companies to do bioenergy projects. The focus to this point has been on thermal power projects.

A 2005 study "Feedstock Availability and Power Costs Associated with Using BC's Beetle-Infested Pine" analyzed the cost of producing power from the wood. [30]

Table 4 Bioenergy Costs/$ MWh

| | |
|---|---|
| Delivered cost of biomass | $32.42 |
| Capital/ROI | $28.58 |
| O&M cost | $9.53 |
| Total cost | $70.53 |

Since 2005 there has been general price inflation in Canada, including inflation of construction costs. In Vancouver the index for general, non-home, construction rose by about 2% per year from 2007 through 2016. If that rate can be assumed to apply for all the costs of the wood waste power plant the unit cost in 2017 would be about $90.00/MWh.

Using a pyrolysis/gasification process municipal sold waste (MSW) can be converted to syngas to be burned to generate electricity. Such processes have been used in Japan and Europe for years where disposal of wastes is expensive as is fuel.

These conversion processes are quite different from the BC landfill methane capture projects that now exist. The latter simply collect methane naturally produced from decaying buried organic material and then burn it in small generation plants.

Surrey BC in 2017 begins operating a biofuels project to process MSW into syngas to fuel the City's fleet of compressed natural gas (CNG) waste collection trucks.

The City collects MSW from 100,000 homes. Based on the BC Ministry of Environment data, Metro Vancouver in 2012 accounted for about 600 kg of MSW per capita. Surrey has a population of about 400,000. That would imply that Surrey would generate about 240,000 tonnes of MSW per year. Surrey has reported that 65% of the MSW is organic waste so about 160,000 tonnes of biogenetic dry matter would be available for conversion into syngas.

Surrey had estimated the capital cost of the facility to be $60 million. The federal government has agreed to provide $16.9 million in funding through the Public Private Partnerships fund.

The Surrey plant could also use the syngas not for fleet fuel but as fuel for a power plant. The power output would be relatively small and the cost quite high, greater than $100/MWh, but this still could be a possibility for some environmentally sensitive urban centers.

iv) Solar Power

Most solar power technology applications in Canada are in home or office non-electric system applications, for space and water heating. The cost of a residential system is in the $ 30,000 to $ 40,000 range. The payback is generally long, but there are government subsidies.

On an industrial scale, there are major solar power plants in the USA, China and India, in the 600 MW to 900 MW range. There are also several solar generating stations in Ontario. A 97 MW plant is located in Sarnia, a 23 MW at Sault Ste. Marie and a 100 MW plant in Kingston. It has been forecast that Ontario could soon have over 2,000 MW of solar capacity. There are no plants in BC, although the feasibility has been investigated.

Costs of energy from some of the large southern latitude photovoltaic plants are reported to be less than $ 100/MWh. Such plants are probably not an option for BC in even the medium term.

## 11. Comparative Costs

From the analysis above the following table shows approximate unit costs of potential new energy supplies for BCH. The environmental, the availability and the storage features of these sources have been dealt with in Section 10.

Table 5 Unit Cost Comparisons

| Source | Cost $/MWh |
|---|---|
| Site C $8.8 billion @ 8% | 152.71 |
| Site C $8.8 billion @ 6% | 121.17 |
| Site C $5.8 billion @ 8% | 104.63 |
| Site C $5.8 billion @ 6% | 83.83 |
| Wind | 100.00 |
| CCGT | 75.00 |
| IPP Hydropower | 110.00 |
| DSBs | 105.00 |
| Bioenergy wood waste | 90.00 |
| Bioenergy MSW | > 100.00 |
| Solar power | > 100.00 |

## 12. Conclusions

The conclusions reached from this Site C - Review to answer the Province of British Columbia's Questions are as follows:

- With a growing province and with the expectation that more of the economy will depend on green electricity rather than fossil fuels, in particular in the transport sector, a new requirement of 10,000 to 14,000 GWH by the 2030's seems reasonable. That is two to three Site Cs;

- There are a number of energy supply alternatives to Site C, the lowest cost would be a CCGT plant, but that is probably not acceptable for environmental reasons. DSBs could be a relatively low-cost source but may not be dependable;
- If Site C was not available to fill part of this energy gap it could be filled by IPP hydropower or wind projects. There are now 80 hydropower IPP EPAs and 7 wind EPAs. At the current average scale of plant, the gap would require another 70 to 100 hydropower plants or 35 to 50 wind power plants. They would not be less costly than Site C power, would not have storage capacity, and would have less availability, 42% and 33% versus 53%;
- The expected unit cost of Site C power is difficult to predict due to rising capital cost estimates over time, the question of sunk costs and the appropriate discount rate. The best estimate that can be provided in this Review is that it is likely in the $110/MWh to $120/MWh range;
- Delaying Site C would be costly, up to $1 billion for a one-year delay. Terminating the project could result in a loss of $3 billion or more, with no benefit. Many jobs would be lost in either case. And in both cases make-up power would be needed, which would be difficult to bring on-line, in most cases would have fewer benefits and would be at least as costly as Site C power, in the $90 to $120/MWh range;
- The delay/termination sunk costs would have to be borne by either ratepayers or by taxpayers;
- While the Province has concerns over ratepayers interests, there is a broader interest that is at least as important, that is the public interest, the welfare and wellbeing of the general public;
- Based on the evidence presented in this Site C – Review, suspension or cancellation of Site C would not serve the public interest or ratepayers interest; and
- If a decision is taken to proceed with Site C there should be consideration given to amending the BCH procurement strategy and adjustments made to project management to better ensure an on budget, on time result. Also an investigation should be carried out into the possibility of profitable new export power markets in Alberta and Alaska.

## 13. Recommendations

It is the recommendation of the Allied Hydro Council of British Columbia to the Province of British Columbia to take the positive decision, in the public interest and ratepayers interest, to proceed with Site C, with the above noted adjustments to the procurement approach and overall project management.

Sivertson & Associates Consulting Ltd.
August 19, 2017

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